Application of Supercritical Carbon Dioxide in Engineered Geothermal Systems

Alvin I. Remoroza
MSc Chemical Engineering, MSc Sustainable Energy

Priority Research Centre for Energy
Faculty of Engineering and Built Environment
School of Engineering
University of Newcastle
Nov 2012
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Alvin I. Remoroza, MSc ChE, MSc S.E.

Thesis Dissertation in partial fulfilment of a
Doctor of Philosophy degree in Chemical Engineering

Supervisors:
Prof. Behdad Moghtaderi
Dr. Elham Doroodchi

Faculty of Engineering and Built Environment
School of Engineering
The University of Newcastle
Callaghan, Nov 2012
I hereby certify to the best of my knowledge and belief that the work done in this thesis is original and contains no material previously published or written by another person, except where due reference has been made in the text.

Alvin I. Remoroza
I hereby certify that the work embodied in this thesis contains published papers/scholarly work of which I am a joint author. I have included as part of the thesis a written statement, endorsed by my supervisor, attesting to my contribution to the joint publications/scholarly work.

Alvin I. Remoroza
I, the undersigned, certify and endorse that several publications listed in the thesis were based from Alvin's thesis from which he contributed and therefore recognised as a co-author.

Prof. Behdad Moghtaderi
Acknowledgments

This thesis is made possible by people who believed in me and shared sacrifices with me in this endeavour called PhD. I am forever grateful and indebted.

I would like to thank my supervisor, Prof. Behdad Moghtaderi, whose research guidance and grants made my studies possible. Similarly, I would like to extend my gratitude to my co-supervisor, Dr. Elham Dorooodchi, for healthy discussions, constructive criticism, and thesis writing assistance.

Thanks to the staff and students of The University of Newcastle, particularly to Neil Gardner, Jane Hamson, Richard Bale and Yanyan Sun of Earth Sciences, and David Phelan and Jennifer Zobec of EMX Unit. I would also like to acknowledge Gillian Hensman, Bernadette Rossiter, and other administrative staff who helped us procure equipment and place travel arrangements for our conference attendances.

I would like to express my appreciation of friendship to my Newcastle and Sydney families: Holdsworth family (Auntie Clovia, Uncle John, James, and Mark), Dorado family (Joyeth, Nikki, and Matthew), Maano family (Jay, Rizza, and Grace), Razal family (Ottoy, Jonyx, and Yuma), Reydick, Sansan, Edwin R, Delfin, Lawrence, Franz, Dimples, Pau, and other friends. They made my stay in Australia still feel like home.

I would also like to recognise the support of Energy Development Corporation in my endeavour and for allowing me to take study leave.

I dedicate this thesis to my family. To Cherrie: Without her sacrifices, this PhD would not have been possible. To Atom: His videos/pictures and the memories of us together as a family brought a smile to my face and made every moment of my life worth it. To Daddy Vino, Mommy Fely, Allen, and Blessel for looking after Cherrie and Atom during my absence. To Nanay Bella, Libella and family, Ate Ching and Kuya Willy, Ate Genia and family, Kuya Rey and family, Ate Grace and family, Kuya Roderick and family, and to the Remoroza and Inaanuran clans, who shaped me into the person I am today through shared experiences and sacrifices and unconditional love to one another.

Thank you, The Alpha and The Omega, for we owe everything from your compassion on us.
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Abstract

The present thesis is concerned with geothermal energy and specifically focuses on engineered geothermal systems (EGS), which are among a portfolio of technology options for power generation from geothermal resources. In this cyclic approach (also known as hot-dry-rocks or enhanced geothermal systems), high pressure water (i.e. "geofluid") is first pumped down a borehole (known as injection well) into a bed of hot fractured rock and forced to travel through the bed, capturing the heat content of the rocks. The hot water is then extracted from a second borehole (known as production well) and sent into a binary power plant, where its thermal energy is converted to electricity. The cooled water exiting the power plant is then injected back into the ground to resume the cycle.

The aim of this thesis is to advance the understanding of CO₂ based EGS power generation process and verify the merits of using CO₂ rather than water for heat extraction from fractured hot dry rocks. The work has been largely driven by the suitable thermodynamic and transport properties of supercritical CO₂ (scCO₂), which makes it a desirable candidate for harnessing geothermal energy from hot dry rocks, particularly in regions where water resources are scarce. However, only a limited number of studies were carried out in the past to assess the viability of the CO₂ based EGS concept. Most of these studies were theoretical examinations of the heat extraction and exergy analysis under a limited range of operational parameters. In addition, research work on the fluid-rock interactions relevant to CO₂ based EGS is also limited and needs further investigation. The present thesis addresses the above knowledge gaps through a combined experimental and theoretical study, resulting to an accurate description of the entire CO₂ based EGS power generation process encompassing the reservoir, wellbore and power plant cycle as well as the fluid-rock geochemical interaction. The specific objectives of the project underlying this thesis were: (1) model development and simulation of the entire CO₂ and H₂O based EGS and the associated power plant cycles, (2) optimisation studies and sensitivity analysis of operating and design parameters affecting CO₂ and H₂O based EGS performance, (3) performance comparison of CO₂ based EGS and H₂O based EGS under the same operating and
reservoir conditions, (4) examination of the effect of reservoir parameters on both CO₂ and H₂O based EGS concepts through detailed 3D reservoir simulations, (5) design and fabrication of a fluid-rock interaction apparatus capable of simulating EGS conditions, and (6) experimental investigation of the fluid-rock interactions at reservoir conditions and its likely impact on the performance characteristics of CO₂ and H₂O based EGS.

One dimensional (1D), 2D, and 3D models of integrated reservoir-wellbore-power plant cycle were developed to provide an overall description of fluid flow in fractured reservoir (channel flow) and in radial fluid flow in homogeneous porous media. It was also created to investigate "3D effects" as well as transient changes during the power generation process. The thermosiphon power generation process was used in CO₂ based EGS model simulations while the Organic Rankine Cycle binary plant with isopentane as the working fluid was employed in the H₂O based EGS simulations.

Mass and energy balance equations associated with the integrated 1D and 2D reservoir-wellbore-power plant cycle model simulations were solved using the Engineering Equation Solver (EES). In the integrated 3D reservoir-wellbore-power plant cycle modelling, the transient geofluid mass and heat flow rates in the reservoir were simulated using TOUGH2/ECO2N software packages while the wellbore flow and power plant cycle calculations were carried out using EES. The use of TOUGH2/ECO2N was validated and calibrated by replicating the results of prior studies done by Pruess (2008) where TOUGH2/EOSM simulator was used.

A fluid-rock interaction apparatus with titanium made wetted components was designed and fabricated to conduct batch and flow-through experimental studies of rock samples with CO₂ and H₂O at pressures up to 50 MPa and temperatures up to 400°C. Surface granite from Moonbi near New England Highway, NSW and drill core samples from Mossgiel 1 and Nambucurra 1 boreholes at Murray-Darling Basin, NSW were collected and used as representatives of hot-dry-rock (HDR) EGS reservoir rock formations. The granite samples were pulverised and analysed for particle size distribution as well as element (fused-bead XRF) and mineral (Rietveld quantitative XRD) compositions prior to any experiments. Fluid-rock interaction experiments were conducted for up to 15 days at different simulated reservoir pressures (20 and 35 MPa) and temperatures.
(200 and 250°C). Fluid effluents were analysed using ICP-OES, and the reacted pulverised granite samples were subjected to further XRF, XRD, and SEM (scanning electron microscopy) analysis.

The following are the key findings of the integrated 1D/2D reservoir-wellbore-power simulations:

- The mass flow rate of CO$_2$ has an inverse relation with the injection temperature in a CO$_2$ based EGS while there is a direct relationship between the mass flow rate of water and injection temperature in CO$_2$ based EGS. These contrasting behaviours can be assigned to the fact that an increase in the injection temperature lowers the CO$_2$ density and hence increases its dynamic viscosity whereas in the case of water, an increase in the injection temperature lowers H$_2$O kinematic viscosity and thereby decreases the dynamic viscosity.

- Reservoir pressure loss is generally higher for H$_2$O than for CO$_2$ because of the higher H$_2$O kinematic viscosity.

- CO$_2$ overall mass flow rate is higher than that of H$_2$O due to lower average CO$_2$ kinematic viscosity at reservoir conditions.

- Wellbore frictional loss of CO$_2$ is greater than that of H$_2$O due to the lower average CO$_2$ density along the length of the wellbore.

- Heat extraction rates of H$_2$O based EGS is generally higher than those of CO$_2$ based EGS due to higher specific heat capacity of water.

- The thermal siphoning is not practical for H$_2$O based EGS because the production pressure is usually lower than the injection pressure.

- Power generation output of H$_2$O based EGS are higher than that of CO$_2$ based EGS and increases almost linearly as injection pressure increases while CO$_2$ based EGS power output shows a parabolic trend. These were found to be due to the dependency of CO$_2$ thermodynamic properties on pressure while H$_2$O thermodynamic properties are almost independent of pressure.
• Reservoir temperature does not influence the overall CO\textsubscript{2} mass flow rate, but CO\textsubscript{2} heat extraction rate increases as reservoir temperature increases due to increase in the specific enthalpy change.

• The maximum power generation of CO\textsubscript{2} based EGS decreases as reservoir pressure decreases due to lower CO\textsubscript{2} production pressure in the wellhead.

• For both CO\textsubscript{2} and H\textsubscript{2}O based EGS, shorter injection to production well distance gives higher fluid mass flow rate due to the increase in pressure gradient (pressure drop/distance) between the injection and production wells.

• As the ratio of production to injection well increases, the CO\textsubscript{2} based EGS power generation output increases due to diminishing CO\textsubscript{2} frictional loss in individual production well as the number of production well increases.

• CO\textsubscript{2} based EGS generally performs better in low permeability reservoirs (typically one order of magnitude decrease in reservoir permeability decreases CO\textsubscript{2} mass flow rates by 27% while H\textsubscript{2}O mass flow rates decreases by 67%).

• The overall thermal efficiency at any specified injection and reservoir conditions is constant regardless of CO\textsubscript{2} mass flow rate.

Batch and flow-through CO\textsubscript{2}-rock interaction experiments show that Ca, Fe, Mg, Al, and Si dissolve in scCO\textsubscript{2}, which was found to be partly due to the presence of H\textsubscript{2}O in the CO\textsubscript{2} stream leaked from the piston accumulator. Geochemical model simulations show that aqueous Si concentration is in equilibrium with the rock minerals after 1 day exposure in the batch experiment. The log of (Na/K) ratios shows the preferential dissolution of albite over k-feldspar. The SEM image analysis of the treated granites shows signs of erosion (i.e. rounded edges and pebble-like surfaces), which is considered to be due to the formation of carbonates in the surface and its subsequent erosion and dissolution (particularly Na\textsubscript{2}CO\textsubscript{3} and K\textsubscript{2}CO\textsubscript{3}) to the fluid. The XFR analysis of the untreated and treated pulverised granites shows very small changes to SiO\textsubscript{2}, Al\textsubscript{2}O\textsubscript{3}, CaO, MgO, Fe\textsubscript{2}O\textsubscript{3}, Na\textsubscript{2}O, and K\textsubscript{2}O major oxide compositions consistent with the ICP-OES analytical results. The Na-K-Mg ternary diagram of the data collected from the fluid-rock experiments shows that the aqueous fluid is far from the equilibrium.
The presence and/or absence of minerals (hornblende or chlorite) in the starting material influences the log of (Na/K) ratios. Hornblende alters or converts to chlorite in the CO₂-H₂O mixture. Moreover, the concentrations of Ca, Mg, and Fe decreases with time, which is considered to be due to the formation of a passive layer of insoluble carbonate minerals in the surface, thus preventing further fluid-rock interaction.

The pressure loss data collected during the flow-through fluid-rock interaction experiments validate the theory that CO₂ has lower reservoir loss than H₂O. The data also validate the correlation between particle size and intrinsic permeability, which predicts that at the same fluid mass flow rate, a medium with a larger particle size has a lower pressure loss.
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Remoroza, A.I., Moghtaderi, B., and Doroodchi, E. (2011, Jan 31-Feb 2). *Coupled Wellbore And 3D Reservoir Simulation Of a CO2-EGS*. Paper presented at the Thirty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, USA.


Chapter 1: Introduction

Geothermal power generation has traditionally relied on hydrothermal reservoirs, and hence has been limited to specific geographical locations. Engineered/Enhanced geothermal systems (EGS), on the other hand, offer the chance to extend the use of geothermal energy worldwide to resources that are not otherwise accessible due to lack of water and/or permeability (Tester, et al., 2006).

The EGS concept is based on extracting heat by creating a subsurface fracture system. In this concept, a heat transfer fluid known as geofluid is injected into a hot dry rock reservoir via an injection well and is forced through the fractured rocks to harvest the heat. The hot geofluid is then collected at the surface (using a production well), and its heat content is converted to electricity typically using a binary power plant. There is a growing interest in EGS mainly driven by the need to use alternative renewable sources of energy to negate greenhouse gas emissions generated by fossil fuels. The main focus of past EGS research and development studies has been on conventional systems where water is used as the geofluid. The focus of the present study, however, is on CO₂ based EGS in which, unlike the conventional systems, the geofluid is supercritical CO₂. This approach facilitates the deployment of EGS to regions where water resources are limited and/or scarce. The CO₂ based EGS has also the added advantage of combining the process of harvesting geothermal energy with a limited sequestration of CO₂ and hence has the potential to act as a carbon sink helping the transition from fossil fuel-based power generation to the renewable one.

Previous findings reported in the literature about the feasibility CO₂ based EGS for power generation are somewhat contradictory, highlighting the lack of a complete understanding of this power generation process. For instance, Karsten and Pruess (2008) showed that heat extraction using CO₂ as geofluid is significantly higher compared with that using H₂O. However, the recent studies published by Agarwal and Anderson (2010) indicate that H₂O based EGS produces 70-80% more net power than CO₂ based EGS and has 80% more cumulative power generated compared with CO₂ based EGS.
Chapter 1: Introduction

The main objective of this study is to advance the understanding of CO₂ based EGS based power generation process and verify the merits of using CO₂ over water as a geofluid. The study presented here is likely to prove useful in worldwide deployment of EGS for base-load electricity generation.

1.1 Motivation

There is now a worldwide drive for utilization of renewable and alternative forms of energy and away from fossil fuels. This has been attributed partly to the anthropogenic effect of CO₂ on climate change (Bernstein, et al., 2007), which has detrimental impacts on human civilization as a whole. Among the available renewable sources of energy, geothermal energy offers great potential because it can offer steady, base-load electricity with minimum pollution and green house gas emission. The incoming technological advances to EGS increase the resource base of geothermal power generation potential and its availability worldwide.

However, to realise this enormous geothermal energy potential using EGS, a number of technical and economic barriers must be first addressed and effectively overcome. These barriers are related to issues as diverse as: (1) precise identification and classification of geothermal resources and accurate estimation of recoverable energy, (2) well drilling technologies and costs, (3) EGS reservoir stimulation and design, (4) energy conversion technologies, and (5) environmental impact of EGS development (Tester, et al., 2006).

Current and past EGS reservoir studies and designs are based on the use of water for hydraulic fracturing and heat exchange medium (Baria, Baumgärtner, Rummel, Pine, & Sato, 1999; D. W. Brown, 2009; D. Brown, DuTeaux, Kruger, Swenson, & Yamaguchi, 1999; Hori, Kitano, Kaieda, & Kiho, 1999; Kuriyagawa & Tenma, 1999; Parker, 1999; Richards, et al., 1994; Sanjuan, et al., 2006; Savage, Bateman, & Richards, 1992; Tenma & Iwakiri, 1998; Tenma, Yamaguchi, & Zyvoloski, 2008). However, using water has its drawback since as a universal solvent, it dissolves rock minerals and precipitate mineral scales in the well and surface facilities (N. Yanagisawa, 2007; Norio Yanagisawa, Matsunaga, & Sugita, 2007; Norio Yanagisawa, Matsunaga, Sugita, Sato,
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& Okabe, 2006, 2008). In addition, it has been documented that part of the fluid injected is lost (sometimes greater than 10%) in the reservoir (D. W. Brown, 2009; Sanjuan, et al., 2006; Tenma, et al., 2008). Therefore, from this perspective, an alternate heat extraction medium or "geofluid" is sought as a replacement for water in EGS applications. Brown (2000) presented a novel EGS concept which utilised supercritical CO₂ (scCO₂) as a geofluid (Figure 1.1). The CO₂ selection was made based on its unique thermodynamic properties as described below. In the CO₂ based EGS process, the cold dense CO₂ is injected into the reservoir of hot fractured rocks where CO₂ is heated. The hot low density CO₂ stream is then flowed up the production wells. Due to the large density difference between the cold injected CO₂ and hot scCO₂ flowing in the production well, the flow can be self-sustaining, and the mechanical pump is not needed to maintain the flow. This phenomenon is referred to as “thermosiphon.”

The use of scCO₂ in a confined closed-loop EGS can offer the following advantages over the use of water as a geofluid: (1) potential thermal siphoning effect due to large density difference between the injection and production fluids, in turn, reducing circulating power requirements, (2) eliminating or significantly reducing mineral precipitation at the surface equipment since pure scCO₂ is a poor solvent for rock minerals, (3) accessing reservoir temperatures in excess of 374°C without silica dissolution with the potential to gain greater thermodynamic efficiencies, and (4) the ancillary benefit of limited CO₂ geosequestration (Brown, 1999, 2000). The CO₂ based EGS concept is particularly suited to the arid regions of Australia where hot dry rocks (HDR) are located and have the potential to be developed into EGS-based power plants (Goldstein, Hill, Budd, Holgate, & Malavazos, 2008a, 2008b, 2009). Australia has an accessible stored geothermal energy which theoretically can supply all of its energy needs for centuries to come. It is estimated that converting just 1% of total contained continental crust heat can supply Australia’s primary energy needs for 26,000 years (Budd & Barnicoat, 2008).
1.2 Overview of the CO$_2$ Based EGS Power Generation

The research on application of CO$_2$ for EGS-based power generation is relatively scarce. Most of the available literatures are numerical modelling of thermodynamic/transport properties and exergy analysis (Atrens, Gurgenci, & Rudolph, 2008, 2009a, 2009b, 2010; Brown, 2000; Pruess, 2006, 2007, 2008; Pruess & Azaroual, 2006) with the main focus being on numerical modelling of fluid flow in the reservoir using the commercially available TOUGH2 simulation software.

Pruess (2008) developed a TOUGH2 model using the equation of state module "EOSM" to examine 3D flow effects in the reservoir. He modelled the system after the European hot dry rock experiment at Soultz-France. The study focused only on the fluid reservoir flow with the analysis being limited to mass flow rate in the production wells and the total heat extraction rates. The main finding was that CO$_2$ heat extraction rates are significantly greater compared with H$_2$O.
Later, a TOUGH2-based reservoir simulation coupled with Chemcad for power generation calculations was conducted by Agarwal and Anderson (2010). The finding of this study showed that H₂O produces 70-80% more net power during the initial 10 years of power generation compared with CO₂. Despite the CO₂’s lower net power output, the power generation process over time was found to be more consistent and stable than that of water.

Although the heat extraction analysis gives a good indication of power potential, a complete numerical modelling of a closed-loop CO₂ based EGS power plant cycle process would give a deeper understanding of the electricity generation potential. In addition, since most of the literature available related to CO₂-rock interactions are based on theoretical and experimental work pertaining to geosequestration of CO₂ at relatively low temperatures, research work on the fluid-rock interactions relevant to CO₂ based EGS also needs attention especially at moderate temperatures commonly found in hot dry rock EGS prospect areas.

1.3 The Present Work

The purpose of this thesis is to advance the understanding of CO₂ based EGS based power generation process and verify the merits of using CO₂ over H₂O for heat extraction from fractured hot dry rocks. This work is a combined experimental and theoretical study with the basic objective of producing an accurate description of the entire CO₂ based EGS based power generation process encompassing the reservoir, wellbore, and power plant cycle as well as the fluid-rock geochemical interaction. More specifically, the objectives of the project are:

- Model development and simulation of the entire CO₂ based EGS.
- Optimisation studies and sensitivity analysis of operating and design parameters affecting CO₂ based EGS performance including injection temperature, well depth, and reservoir temperature.
- Performance comparison of CO₂ based EGS and H₂O based EGS at the same operating and reservoir conditions.
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- Evaluation of the effect of reservoir parameters on CO₂ based EGS performance through detailed 3D reservoir simulations.
- Design and fabrication of a fluid-rock interaction apparatus capable of simulating EGS conditions.
- Identification of fluid-rock interactions at reservoir conditions that may affect performance of CO₂ based EGS and the comparable H₂O based EGS.

Figure 1.2 shows the outline of the project. The application of CO₂ for EGS is examined theoretically using the numerical modelling approach. First, a one dimensional (1D) or single channel model was developed to simulate fluid flow in a fractured reservoir. While the 1D model can provide an overall description of fluid channel flow in a fractured reservoir, it is not able to give an insight into the radial flow of the fluid in homogenous porous media. Therefore, a 2D model is developed. The model was then extended further to develop a 3D model to investigate three dimensional effects and transient changes during production. The fluid-rock geochemical interaction is also investigated numerically. New experimental data are obtained on the fluid-rock interaction of granite bodies and CO₂ under batch and continuous operating conditions (flow-through) in a pressurised experimental setup. The batch experiments simulate the reaction of stagnated fluid with the granite bodies while the flow-through experiment simulates the fluid flow in the reservoir from the injection to production well. Granites from the surface and drill cores are used in the experiment to study fluid-rock interactions. The experimental data obtained are then compared with the theoretical values calculated using geochemical speciation and simulation software, Geochemist's Workbench and PHREEQC. The findings of both the experimental and numerical studies are compared with H₂O based EGS to verify the merits of using CO₂ over H₂O as a heat extraction fluid for the EGS power generation process.
1.4 Thesis Structure

In Chapter 2, an overview of the literature on geothermal energy and engineered/enhanced geothermal system is presented with the aim to introduce the reader to the general knowledge on EGS and give a perspective on the challenges it faces. Hydrothermal and HDR resources are briefly differentiated and defined. A summary on the history and current trend of EGS development are presented. The concept of EGS in Australian context is given primary focus. A critical review of the limited literatures relevant to CO₂ based EGS is presented in Section 2.2.

The theoretical background is presented in Chapter 3 focusing on the general principles and theories used in the present study. The thermodynamic properties of each process components in a geothermal power plant and different power plant configurations are presented to identify the optimal system for EGS application. Basic concepts in reservoir flow and geothermal reservoir engineering are defined, which is important when conducting detailed 3D reservoir simulations. The chemistry of fluid-rock
interaction including kinetics and mineral equilibria is introduced and briefly reviewed in Section 3.3.3.

Chapter 4 presents and describes the integrated reservoir-wellbore-power plant cycle numerical modelling for EGS using Engineering Equation Solver (EES) custom made programs. Detailed numerical methods for reservoir-wellbore flow and power plant cycle analysis are presented. Reservoir flows are simulated in 1D and 2D. The 1D reservoir flow was conducted to simulate flow in fractured reservoir where it can be best described as a single channel flow, and the 2D can represent radial reservoir flow in homogenous porous media. The effect of different operational and reservoir parameters on mass flow rates, heat extraction rates, total exergy, and power generation potentials of CO₂ and H₂O based EGS are presented and compared. Injection pressure is chosen as the primary independent variable in the presentation of results since it is most often the variable that is set or pre-determined when assessing reservoir or well performance. The results from this chapter only represent a snapshot of the entire reservoir-power production process since it does not involve time variable. The process is good for quick assessment of EGS power generation potential for all intent and purposes.

A detailed 3D reservoir simulation coupled with wellbore and power plant cycle modelling is presented in Chapter 5. For the 3D reservoir simulation, TOUGH2—which as noted earlier is a numerical simulator for non-isothermal multi-phase and multi-component flows in permeable media--was used (Pruess & Narasimham, 1985; Karsten Pruess, 2004; Karsten Pruess, Oldenburg, & Moridis, 1999). A modified version of ECO2N equation of state module was also employed to simulate both CO₂ and H₂O flows in the reservoir (Pruess & Spycher, 2007). The results from this chapter present the "3D" effects on fluid reservoir flow and the transient changes during the simulated lifespan of the power plant.

The theoretical and experimental results of the fluid-rock interaction under conditions pertinent to EGS are presented in Chapter 6. The first section of this chapter describes the experimental set-up and in particular the fluid-rock interaction apparatus built as part of this study to conduct both batch and flow-through experiments. This apparatus is capable of operating at pressures up to 50 MPa and temperatures up to 400°C. The
wetted parts of the apparatus are made of corrosion resistant titanium metal. CO$_2$-rock interaction batch experiments at 20 MPa and 200 and 250°C, and flow-through fluid-rock interaction experiments at 20 MPa and 250°C using CO$_2$ and H$_2$O at different flow rates were conducted. The second section (6.2) presents the descriptions and preparation of the granites used in the experiments. Granite samples were collected from different locations such as the surface granites from the Moonbi granite outcrop in the New England Highway and the granite drill core samples from Nambucurra 1 and Mossiel 1 wellbores at Murray-Darling Basin, NSW, Australia. The results and discussion on batch and flow-through fluid-rock interaction experiments are presented in Section 6.3.

The conclusions and recommendations are presented in the final chapter (Chapter 7), followed by the appendices.
Chapter 2: Literature Review

Literature review on Enhanced/Engineered Geothermal System (EGS) is presented in this chapter. The first part is a review on the general EGS concepts utilising water as geofluid. The review encompasses the economic, power conversion technology, drilling technology, reservoir engineering and management, and water resource aspects of EGS development as applied to Australian context.

The second part of the chapter provides a critical examination of the available literature on CO₂ based EGS.

2.1 Engineered Geothermal Systems

Geothermal energy is thermal energy stored in the earth and is distributed between the host rock and the fluids contained in its pores and fractures at temperatures above the ambient. For most of the continental crusts (i.e. Australia), heat source is primarily due to: (1) upward convection and conduction of heat from the Earth’s mantle and core and (2) heat generated by the decay of radioactive elements in the crust, particularly isotopes of uranium, thorium, and potassium (Tester et al., 2006).

Economic viability of conventional geothermal resources or hydrothermal systems depends on the existence of: (1) a large heat source (i.e. near magma bodies), (2) a permeable reservoir that is accessible within current permissible drilling depth, (3) hot fluids, (4) an impermeable cap rock, and (5) a fluid recharge mechanism that sustains productivity over time. These are the case for most of the active geothermal regions in world like the USA, Philippines, Indonesia, New Zealand, Japan, Iceland, Italy, Mexico, and Costa Rica. These countries are located in places where there are high geothermal gradient anomalies associated to tectonic plate boundaries and/or recent volcanic activities (DiPippo, 2008b; Tester et al., 2006).
In some regions around the world, however, the geothermal reservoirs do not contain significant quantities of water and are not considered as hydrothermal. Such reservoirs are typically dominated by large masses of hot rock bodies and are referred to as hot dry rock (HDR). Harvesting the heat content of HDR resources requires a significant level of technical knowhow, preparation, and engineering. That is why these resources sometimes referred to as engineered geothermal systems, is a reference to the fact that these resources were created by hydraulic pressurization of a portion of multiply jointed but re-sealed rock mass within previously impermeable body of hot crystalline basement rock that is totally confined. The man-made nature of EGS allows the freedom to choose production temperature by selecting the drilling depth and reservoir size by the amount of fluid injected into the reservoir (Brown, 2009). Therefore, EGS can be considered as an engineered reservoir created to extract economical amounts of heat from high temperature rock formation with low permeability and/or porosity by stimulation, creating/re-opening fractures, and flow networks where fluid can be circulated through a system of injection and production wells.

EGS reservoir preparation is carried out in several steps, the first of which is drilling the well into the hot, low permeable, and hard crystalline basement rock, usually granite. The second step is hydraulic stimulation to open previously sealed natural fracture networks and/or induce thermal cracking of the hot rock. Micro-seismic event monitoring and other geophysical methods and techniques are then employed to determine the position, propagation, orientation, and size of the created EGS reservoir. The second well is then drilled to access the created sufficiently sized EGS reservoir and ensure connectivity of the two wells. Fluid circulation is then tested and additional hydraulic and/or chemical stimulations are performed to improve fluid flow between the wells. After establishing sufficient fluid circulation, commercial power generation can now commence. Monitoring of the fluid chemistry is then employed to determine mineral scaling potential that could affect the long term fluid circulation. When necessary, chemical scale inhibitor can be installed.

The concept of EGS was first devised in the Los Alamos National Laboratory in the early 1970s, which led to the creation of the first EGS (called then as HDR) in Fenton
Hill HDR Test Site, Los Alamos, New Mexico, USA. The project proponents successfully created two separate HDR reservoirs in deep, hot crystalline rock at depths of 2800 m and 3500 m and temperatures of 195°C and 235°C, respectively. The reservoirs were flow tested and were able to produce 4-10 MW of thermal energy for a considerable length of time. It was the first proof that recovering useful amounts of energy from EGS is technically feasible (Brown, 2009). Other EGS projects that followed were at Rosemanowes, UK; Hijori and Ogachi, Japan; Soultz, France; and others. Australia’s Cooper Basin EGS project finished the “Proof of Concept” in early 2009 and is in the financial decision making process to enter the commercial demonstration phase as of writing (http://www.geodynamics.com.au/IRM/content/gbp_threestage.html accessed on July 12, 2010).

As of 2008, several companies in Australia have already undertaken drilling and geophysical surveys for EGS applications (Goldstein, Hill, Budd, Holgate, & Malavazos, 2009): Geodynamics-Origin Joint Venture (5 deep holes, maximum depth of 4,911 m), Green Rock Energy (1 hole to 1935 m), Petratherm (3 holes, maximum depth of 1,807 m), Geothermal Resources (8 holes, maximum depth of 1,761 m), Inferus Resources (2 holes, maximum depth of 1,034 m), Torrens Energy (7 holes, maximum depth of 760 m), Panax (Scopenergy) (5 holes, maximum depth of 531 m), Eden Energy (1 hole, maximum depth of 512 m), KUTh Energy (37 holes, maximum depth of 300 m), Greenearth Energy and Pacific Hydro (gained access to boreholes to measure geothermal parameters), Hot Rock Ltd (completed an MT survey near pre-existing petroleum wells), and Ergon (continued to operate the Birdsville geothermal power plant).

2.1.1 Australian EGS Resource Base

The estimated Australian crustal temperature at 5 km depth is shown in Figure 2.1. This figure roughly shows the potential sites for EGS through detailed exploration, and analysis of existing data must be evaluated to determine its commercial viability. One has to look for the essential components of the hot rock model in the Australian context: (1) buried, high-heat producing granites and (2) 3-5 km low thermal-conductivity
sediments overlying the hot granite bodies. Information about the heat-generation capacity and geochemical composition of the hot granites as well as the composition, conductivity, and thickness of overlying insulating sediments should also be studied.

A total of 359,723 km$^2$ has been licensed for geothermal exploration and development, and it is expected that investment will exceed AU$1,523 million by 2013 for proof of concept geothermal projects (Goldstein, Hill, Budd, Holgate, & Malavazos, 2008a, 2008b; Goldstein et al., 2009).

Figure 2.2 shows a map of contained crustal energy. This is calculated based on Austherm07 comprising two grids with 5 km x 5 km cells: one (lower grid) for temperature at 5 km depth and an upper grid produced by interrogating the database to predict the depth at which 150°C would be reached (minimum temperature required for EGS developments). The average temperature, volume, and estimated contained heat were calculated for each cell. The calculated contained energy in the upper 5 km of Australia’s crust was estimated to be 1.9 x 10$^{25}$ Joules; just 1% of this is enough to supply Australia’s primary energy needs for 26,000 years. This is not taking into account the energy contained below 5 km and the heat generation capacity of the rock due to radiogenic properties of the heat source (Budd, Holgate, Edward Gerner, & Ayling, 2007).
Figure 2.1: Estimated crustal temperature at 5 km depth (Geoscience Australia, map derive from the AUSTHERM07 (Chopra & Holgate, 2005) and OZ SEEBASE™ sediment thickness data (FrogTech, 2006)).
2.1.2 EGS Economic Model

The economics of an EGS project should compete with the current technologies delivering electricity to the consumers. However, without an existing commercially mature EGS power plant, cost competitiveness can only be analysed and compared using economic models.

Any economic model takes into account the cost and performance factors of an EGS project to estimate the levelised busbar cost of producing electricity or levelised
electricity cost. Levelised cost, as defined by the Australian Geothermal Energy Association, is the time series of the capital and operating expenditures divided by the net power supplied, discounted to their present values (Knights, 2009).

AGEA proposes the following methodology for the calculation of levelised electricity cost:

- Expenditures to include all the cost associated to the delivery of the net power to the grid or end-user.
- Project timeline starts from the evaluation of the project up to decommissioning.
- Capital expenditures include drilling costs, power plant and machinery, power lines and associated costs needed to connect to the grid or end users, and other surface facilities needed to operate the power plant. Capital expenditures exclude income-taxes and other benefits from generating renewable energy but include the cost of emitting green house gases.
- Net electricity takes into account plant availability and variability, if applicable, over the project lifetime.
- Operating and maintenance costs include the cost of make-over or additional drilling costs to extend the project life, permit and license fees, administration, insurances, and any royalties payable for the extraction of geothermal energy.
- The discount rate is on a pre-tax basis.

The equation to be used for calculating the levelised cost of electricity, \( L_C \), is

\[
L_C = \frac{\sum_t \left[ (I_t + M_t)(1 + r)^{-t} \right]}{\sum_t \left[ E_t(1 + r)^{-t} \right]} \tag{2.1}
\]

where \( I_t \) is the investment cost in year \( t \), \( M_t \) is the operating and maintenance costs in year \( t \), \( E_t \) is the net electricity generation in year \( t \), \( r \) is the discount rate, and \( \sum_t \) is summation over the project lifetime.
Unlike conventional power plant technologies, fuel cost in EGS is embedded in the capital, operating and maintenance costs of the wells, and subsurface system (i.e. reservoir stimulation). Initial capital investment cost for EGS is therefore expected to be higher than conventional power plant technologies, but the operating and maintenance cost is lower and is more predictable (in contrast, fuel cost for coal or natural gas power plants depends on demand and supply and often fluctuates). Since EGS is an unproven technology, the discount rate used in an economic model is usually higher due to the associated investment risks, and this has an impact on the overall economic viability of an EGS project.

Factors that affect the economic viability of an EGS project include (1) thermal gradient or the temperature increase with depth, (2) reservoir temperature, and (3) production well flow rate or the reservoir productivity (Armstead & Tester, 1987). The thermal gradient will dictate the depth of drilling (hence the drilling cost) to reach the commercially viable resource temperature. The target reservoir temperature, on the other hand, will affect the surface plant cost as higher temperature will presumably give higher production fluid enthalpy, which will dictate the type and size of energy conversion technology to be used. The well’s productivity will affect the rate of reservoir thermal depletion, hence project lifetime. The interplay among these factors should be considered when the optimum economic value of an EGS project is being assessed and/or decided.

In 2010, the Australian Department of Energy, Resources and Tourism, and Geoscience Australia released the cost competitiveness of different energy technologies based on the assessment of Electric Power Research Institute (EPRI) for the year 2015 and 2030 as shown in Figures 2.3 and 2.4, respectively (ABARE, 2010). The technologies covered included:

(1) Coal (black and brown coal) – including single cycle pulverised coal (SCPC), pulverised coal with oxy-combustion (PC-Oxy), and integrated gasification combined cycle (IGCC), all with and without carbon capture and storage (CCS).
Chapter 2: Literature Review

(2) Gas – open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT), both with and without CCS.

(3) Wind

(4) Geothermal – EGS and sedimentary aquifer (HSA).

(5) Nuclear

(6) Solar thermal including central receiver and parabolic trough, all with and without storage.

(7) Solar photovoltaic (PV) including two axis, single axis, and fixed.

These figures show the hot dry rock geothermal levelised cost could vary from AU$100 to about AU$200/MWh comparable to wind, nuclear, CCGT CCS, PC-Oxy black coal, and SCPC CSS black coal. Hot sedimentary aquifer geothermal is cheaper than the hot dry rock geothermal with cost figures between AU$100 and AU$150/MWh.

In comparison, the levelised cost calculated by (Cooper, Beardsmore, Waining, Pollington, & Driscoll, 2010) ranges from AU$94–AU$115 for HSA and AU$92–AU$110 for hot dry rock EGS, although site-specific effects will strongly influence the results. However, the authors warned that levelised cost may not reflect project risks (geological and engineering) inherent to EGS and therefore do not show definite viability of the project. Levelised cost is sensitive to many parameters including project life and discount rate. Another financial method that can be used for economic comparison is net present value, which may require a lot more detailed cash flow and balance sheet.
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Figure 2.3: 2015 technology ranking of different energy technologies in terms of levelised electricity cost and CO₂ emissions.

Figure 2.4: 2030 technology ranking of different energy technologies in terms of levelised electricity cost and CO₂ emissions.
2.1.3 Drilling Technology and Cost

Drilling and completion tests of production and injection wells contribute significantly to the total investment costs of a geothermal project. This could account for more than 50% of capital investment costs. A comparison of the cost of completed geothermal and oil/gas wells is shown in Figure 2.5. This figure is based on the updated MIT drilling depth index (Tester et al., 2006). The Wellcost Lite model (Mansure, Bauer, & Livesay, 2005) was used to predict geothermal well costs based on a wide array of factors affecting drilling costs for geothermal wells. As can be seen, similar to oil and gas wells, geothermal well drilling cost varies non-linearly with depth. However, the cost of drilling geothermal wells is often 3 to 5 times the cost of oil and gas wells of comparable depths. The model identified that the higher number of casing strings required by geothermal well increases its costs significantly higher compared with similar oil/gas well depth (Augustine et al., 2006).

Emerging technologies that could potentially reduce drilling costs include (1) expandable tubular casing (Lohbeck, 1993), (2) drilling-with-casing which uses longer casing intervals but fewer strings, (3) use of smaller increment in well casing diameter with depth, (4) under-reaming to increase borehole diameter, and (5) revolutionary technologies that address issues in the rate of penetration in drilling, i.e. hydrothermal flame spallation and fusion drilling (Potter & Tester, 1998), chemically enhanced drilling (Polizzotti, 2003), and shot-abrasive assisted drilling (Curlett, 2006).
Figure 2.5: Costs of completed geothermal and oil and gas wells as a function of depth in year 2004 U.S. $ (Tester, et al., 2006).

2.1.4 Reservoir Engineering and Management

To tap the enormous energy potential of hot buried granites and other geothermal resources in Australia and elsewhere, the understanding of reservoir behaviour and stimulation are paramount in making the EGS a sustainable and commercially feasible option. The 2006 MIT report on the future of geothermal energy identifies several areas that need further research and investigations to build an effective EGS reservoir management (Tester et al., 2006). These are:
• Assessment of the size of the stimulated volume and heat-transfer area.
• Development of high-temperature downhole tools.
• Better understanding of rock/water interactions.
• Methods for coping with flow short circuits.
• Strategy for dealing with formation temperature decline.
• Methods to control growth of fractured volume.
• Improvement in reservoir modelling.

2.1.5 Energy Conversion Technologies


New geothermal energy conversion technologies recently introduced include the use of supercritical Rankine cycle presented in Figure 2.6 (Gu & Sato, 2002; Moghtaderi & Doroodchi, 2009), Euler turbine, and the Variable Phase Cycle (Welch & Boyle, 2009). These technologies offer higher conversion efficiencies compared to the current conventional binary power plants.

Higher thermal efficiency can be achieved using the supercritical Rankine cycle by adding a heat regenerator in a conventional cycle and careful selection of suitable working fluids with sufficiently low critical pressures. The heat regenerator utilises the unused thermal energy of the turbine outlet stream in the heat-up of the cold working fluid exiting the circulation pump. The combination of supercritical power generation
and heat regeneration has been developed and commercialised into a unified platform called GRANEX technology (Moghtaderi & Doroodchi, 2009).

Euler turbine is a radial outflow reaction turbine consisting of a nozzle row, blade row, and diffuser with lower operating speed to approximately half that of comparable radial inflow machines, reducing the size and losses of a gearbox while also improving rotor dynamics. The design is erosion resistant, enabling its wide use with expansions that drop into the wet region of the working fluid (Welch & Boyle, 2009).

In VPC, the almost isentropic expansion of the gas converted the enthalpy into two-phase kinetic energy, as shown in Figure 2.7. Pressure and shear forces of the expanding gas break up the liquid phase into small diameter droplets, transferring momentum and accelerating both phases efficiently at the same time. The variable phase turbine is composed of a set of individual, fixed nozzles and an axial impulse rotor. The inlet to the nozzle can be liquid, two-phase, supercritical, or vapour (Welch & Boyle, 2009).
Figure 2.6: The schematic diagram of Regenerative Supercritical Rankine Cycle (top) after Moghtaderi and Doroodchi (2009). T-s diagram of ORC, Kalina and supercritical rankine cycle (bottom).

Figure 2.7: The schematic diagram of the Variable Phase Cycle, after Welch and Boyle (2009). VPT means variable phase turbine.
2.1.6 Water Requirement and Availability

Advanced planning and allocation of an EGS project water requirement is essential to avoid environmental and technical issues in the future. Water is an important commodity, and its resources should be managed carefully.

A study conducted on the water requirement of an EGS project in Australia concluded that for well configuration comprising 1 production and 2 injection wells with 600 meter well separation approximately 280,000 m$^3$ of water will be needed over a period of 20 years (Cordon & Driscoll, 2008; Driscoll, 2009). Possible sources of water for EGS consumption are ground and surface water and co-produced fluid from oil and gas wells. The amount of rainfall in an area greatly affects surface and ground waters, as it is the main recharge mechanism in the water-cycle. Rainfall in Australia is highly variable (Figure 2.8), and the distribution is not uniform (Figure 2.9). The rainfall levels in Australia are generally low and the continent is generally considered a dry continent. This is a significant barrier for large-scale deployment of EGS in Australia. Co-produced fluid from hydrocarbon projects (if allowed) can be also used for EGS application upon detailed assessment of availability and suitability of the co-produced fluid. There are no reliable estimates on the quantity or availability of the water co-produced during oil and gas exploration.

2.2 CO₂-Engineered Geothermal Systems

Table 2.1 shows in chronological order the research done by selected authors directly and indirectly related to CO₂ based EGS. This gives an overview of the research already conducted on the topic and also presents a summary of knowledge gaps. From these it can be seen that a combined reservoir-wellbore/power plant model is lacking. The 1D, 2D, and 3D versions of such an integrated reservoir-wellbore and power plant numerical simulations are needed to gain a greater insight into the performance of CO₂ based EGS. These models should rely on realistic parameter assumptions (i.e. turbine and pump efficiencies, wellbore frictional losses, acceleration effects, etc.). Also, equally important are CO₂-rock and CO₂-H₂O-rock studies which have received a very limited attention in the past despite the importance of chemical reactions between CO₂ and porous rocks and their detrimental impacts on the performance characteristics of EGS. Below is a critical examination of the relevant literature.

Fluid dynamics and heat transfer numerical simulations performed in the past studies have established that CO₂ is comparable to H₂O in terms of mining heat from hot fractured rocks. Larger compressibility and expansivity of scCO₂ increase the buoyancy, thus reducing circulation pumping requirements (Pruess, 2006; Pruess & Azaroual, 2006).

Pruess (2008) performed 2D and 3D reservoir simulations of injection/production behaviour of an EGS operated with CO₂ as working fluid using TOUGH2 with fluid property module “EOSM,” which is not commercially nor publicly available. TOUGH2 is a general-purpose numerical simulation program for multi-phase fluid and heat flow in porous and fractured media for applications in geothermal reservoir engineering, nuclear waste disposal, unsaturated zone hydrology, and geologic storage of CO₂ (Pruess, Oldenburg, & Moridis, 1999). His simulations examined production behaviour in 2D areal model at different reservoir pressures and then assessed 3D flow effects on energy recovery. Larger energy (heat) extraction for CO₂ compared with H₂O was predicted in his 3D reservoir simulation at 20 MPa and 200°C reservoir conditions and 20°C bottom-hole injection temperature. However, he did not attempt to predict the total
exergy at the surface, which is more important in predicting the power generation potential of the system. In addition, his 3D reservoir simulation studies did not expand to cover wider reservoir temperature and pressure ranges to gain better understanding on the effect of different reservoir conditions on CO\textsubscript{2} based EGS power generation potential.

Three dimensional reservoir simulations of EGS with CO\textsubscript{2} as working fluid modelled after the European HDR experiment at Soultz show greater heat extraction rates for CO\textsubscript{2} compared with water. The preferential flow of cold dense CO\textsubscript{2} at the bottom of the reservoir increased thermal depletion over time, thus resulting to accelerated thermal breakthrough, which can be avoided by producing at a limited depth interval at the top of the reservoir (Pruess, 2008).

In 2010, Haghshenas Fard, Hooman, and Chua (2010) ran computational fluid dynamic (CFD) numerical simulations of CO\textsubscript{2} thermosiphon, predicting reservoir characteristics based on a system of parallel identical ducts (fractures). They concluded that the overall heat transfer coefficients of the reservoir are functions of fluid thermo-physical properties, injection mass flow rate, and fracture wetted periphery. They also observed that at some reservoir length and well depth, CO\textsubscript{2} thermosiphon performance characteristics in terms of heat transfer and pressure drop were superior to H\textsubscript{2}O based EGS.

Agarwal and Anderson (2010) compared the net electricity generation of CO\textsubscript{2} and H\textsubscript{2}O based EGS using the same mass circulation flow for both fluids. They concluded that H\textsubscript{2}O based EGS generates 70-80\% more power compared with CO\textsubscript{2} based EGS.

Some of the observed shortcomings of using scCO\textsubscript{2} include lower heat capacity and large frictional losses in the wellbore. Studies, however, indicate that in less permeable and low-temperature shallower reservoirs, CO\textsubscript{2} has a production exergy similar to H\textsubscript{2}O. Insignificant exergy difference between CO\textsubscript{2} and H\textsubscript{2}O based system was also observed when very large diameter boreholes were considered (Atrens, Gurgenci, & Rudolph, 2008, 2009b).
Some of the materials published regarding CO$_2$ thermosiphon, however, showed some inaccuracies. The exergy analysis by Atrens et al. (2009b), for instance, used the following equation for calculating pipe frictional losses:

$$
\Delta P_{j,well} = f \frac{\Delta z}{D} \rho \frac{v^2}{2} = f \frac{8\pi^2 \Delta \dot{m}^2}{\rho D^5} (2.1)
$$

However, if one begins from the fluid velocity $v$ (Eq 2.2) and substitute it in Eq 2.1, one would realise that the correct form of pipe friction loss is given by Eq 2.3 rather than that shown in Eq 2.1.

$$
v = \frac{\dot{m}}{\rho A} = \frac{\dot{m}}{\rho (\frac{\pi D^2}{4})} = \frac{4\dot{m}}{\rho \pi D^2} (2.2)
$$

$$
\Delta P_{j,well} = f \frac{8\Delta \dot{m}^2}{\pi^2 \rho D^5} (2.3)
$$

In other papers (Atrens, Gurgenci, & Rudolph, 2009a, 2010), the change in enthalpy of fluid down the wellbore was calculated from

$$
\Delta h = g\Delta z - \frac{v^2 \Delta z}{P} - \frac{2\Delta z}{\rho g} \quad \text{and}, (2.4)
$$

$$
\Delta h = g\Delta z - \frac{v^2 \Delta z}{2} (2.5)
$$

Yet one of the assumptions is that there is no heat flow across the boundaries of the wellbore (adiabatic flow). Equations 2.4 and 2.5 are the fluid’s total change in energy down the wellbore and may not be directly equivalent to change in fluid enthalpy. From thermodynamics, change in enthalpy is defined as:

$$
dH = TdS - VdP \quad (2.6)
$$
where $TdS = \partial Q = \text{heat added to the system in a reversible process}$, $V$ is volume, and $dP$ is change in pressure. Specific enthalpy can only be uniquely defined by a two state variable, e.g. pressure and temperature or pressure and specific entropy, etc.

In the same paper, electricity generation from CO$_2$ and H$_2$O based EGS were compared, but this time, pipe frictional losses and acceleration effects in the wellbores were neglected, which are significant for CO$_2$. In their water/isopentane binary plant, they specified the isopentane working pressure at 3.2 MPa (with corresponding vapour temperature at $188^\circ$C). At this condition, the expanding gas at the turbine will produce a two-phase fluid (based on temperature-entropy diagram), which could lead to erosion problems in the turbine blades. They also assumed 100% turbine and pump efficiencies, which is unrealistic.


Numerical simulations of CO$_2$-H$_2$O-rock interaction showed that diffusion of CO$_2$ in the periphery of CO$_2$ based EGS may induce dissolution of primary minerals and precipitation of secondary carbonate and clay minerals. This reduces porosity which could result in a formation of low permeability barrier that may affect reservoir growth and longevity while on the other hand offer geologic storage of CO$_2$ as an added benefit (Xu & Pruess, 2010; Xu, Pruess, & Apps, 2008). CO$_2$ based EGS will develop three
distinct zones: a central zone or “core” of single supercritical CO₂ phase (Zone 1), a surrounding intermediate zone consisting of a two-phase water-CO₂ mixture (Zone 2), and an outer or peripheral zone of single aqueous phase with dissolved CO₂ (Zone 3) (Fouillac, Sanjuan, & Czernichowski-Lauriol, 2004; Ueda, et al., 2005).

![Figure 2.10: Schematic of the three zones with different phase compositions in an EGS operated with CO₂. Source: Xu et al.(2008).](image)

Experimental studies on CO₂-rock mineral system in a hydrothermal autoclave at 100°C and 10 MPa indicated that minute amounts of H₂O in pore spaces of quartz and granite rocks and the catalysis of Hasteloy C hydrothermal autoclave contributed to a reduction of CO₂ and H₂O and produced some organics that led to Si dissolution. This generated organic silicon compounds in the scCO₂ fluid (H. Lin, et al., 2007; Hongfei Lin, Fujii, Takisawa, Takahashi, & Hashida, 2008). The result suggests that the presence of organic compounds in the rock, which can be found in trap sediments, will be dissolved in scCO₂ and might react with quartz dissolving Si and forming organic silicon compounds in the scCO₂. This also has implications on the used wells and pipes made of carbon steel, which needs to be investigated.

Experiments conducted in sandstone formation using CO₂ also revealed some level of dissolution of ankerite/dolomite and Al-silicates which could enhance porosity and permeability. However, end-member carbonates, anhydride, and alteration of K-
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feldspar to form kaolinite could affect injection (Bertier, et al., 2006; Shiraki & Dunn, 2000).

Experiments conducted in a flexible cell hydrothermal apparatus simulating a saline aquifer storage scenario at 200°C and 200 bars injected with CO_2 showed that geochemical reactions extend beyond simple aqueous dissolution of CO_2 and precipitation of carbonate (Kaszuba et al., 2003, 2005). This has significant implications for the security and safe geological repository of CO_2.

A pilot scale project located near the Moomba plant in Cooper Basin is being considered for a small EGS demonstration plant utilizing CO_2 captured by the plant. One injection and one or more production wells will be drilled through sedimentary formations and up to 500 meters deep into the granitic basement. It is expected that the basement rock will be water saturated; thus, the initial production would be almost 100% water, and the percentage of CO_2 will gradually increase as the pilot EGS is being exploited. The corrosive nature of CO_2-water mixture in the production wells would require corrosion resistant materials (Reichman, Bresnehan, Evans, & Selin, 2008).

Studies have been conducted on CO_2 sequestration by mineral carbonation in geothermal fields (Kaieda, et al., 2008; Kaieda, et al., 2009; Ueda, et al., 2005). These studies gave insights on the possible CO_2-H_2O-rock interactions at conditions where H_2O is the predominant fluid in the system. Water is saturated with injected CO_2, and then CO_2 is captured and precipitated as carbonate minerals at depth. Calcium released from granitic rocks in the reservoir and the subsequent formation of calcite minerals will play a role in permeability enhancement/deterioration of reservoir formation and should be investigated in future studies.

An important step in creating EGS is reservoir stimulation by hydraulic thermo-fracturing of re-sealed fractures in the crystalline basement rock. This procedure will inadvertently introduce water in the reservoir, adding more to the in situ pore water. Injection of scCO_2 to the newly created EGS reservoir will create different fluid-rock interaction scenarios. During the initial stages of CO_2 injection, H_2O-CO_2-rock interaction will happen (it may be that H_2O will be dissolved in CO_2 or CO_2 will be
dissolved in H₂O, depending on the relative quantities of CO₂ and H₂O). Water in the periphery of the reservoir will be pushed outward and might react with the surrounding rock. There will also be a region where CO₂ with minute amounts of H₂O will interact with the host rocks. A simulation conducted by Pruess and Spycher (2010) found that in a fractured reservoir, CO₂ breakthrough at production wells would occur rapidly then subsequently a two-phase H₂O-CO₂ mixture would be produced for a few years, followed by production of a single phase of scCO₂. However, significant dissolved water concentrations will persist in the CO₂ stream for many years.

### 2.3 Research Gaps

Several research gaps have been identified based on the literature review done in this study. While not all of the research gaps have been addressed in this study, the list below was the research gaps identified from the present study.

1. Integrated reservoir-wellbore-power plant modelling of H₂O and CO₂ based EGS (discussed in Chapters 4 and 5)
2. Effect of the number of spatial dimensions on reservoir modelling of H₂O and CO₂ based EGS (discussed in Chapter 5)
3. In-depth analysis on the effect of fluid thermodynamic and transport properties on the performance of H₂O and CO₂ EGS (discussed in Chapters 4 and 5)
4. In-depth analysis on the effect of operational/reservoir parameters on the performance of H₂O and CO₂ EGS (discussed in Chapters 4 and 5)
5. H₂O-rock interaction at HDR EGS conditions (discussed in Chapter 6)
6. CO₂-rock interaction at HDR EGS conditions (discussed in Chapter 6)
7. H₂O-CO₂-rock interaction at HDR EGS conditions (discussed in Chapter 6)
8. Effect of fluid-rock interactions on the performance of EGS and the effect on the integrity of wellbores and piping systems (i.e. effect of CO₂-H₂O mixtures on carbon steel pipes and cements)
<table>
<thead>
<tr>
<th>Author/s</th>
<th>Year</th>
<th>Title</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown, D.W</td>
<td>2000</td>
<td>A Hot Dry Rock Geothermal Energy Concept Utilizing Supercritical CO₂ Instead Of Water</td>
<td>Proposes the use of CO₂ for EGS, thermodynamic analysis</td>
</tr>
<tr>
<td>Kaszuba, J.P., et al.</td>
<td>2003</td>
<td>Carbon dioxide reaction processes in a model brine aquifer at 200°C and 200 bars: implications for geologic sequestration of carbon</td>
<td>CO₂-Brine experiments for sequestration</td>
</tr>
<tr>
<td>Kaszuba, J.P., et al.</td>
<td>2005</td>
<td>Experimental evaluation of mixed fluid reactions between supercritical carbon dioxide and NaCl brine: Relevance to the integrity of a geologic carbon repository</td>
<td>CO₂-Brine experiments for sequestration</td>
</tr>
<tr>
<td>Ueda, A., et al.</td>
<td>2005</td>
<td>Experimental studies of CO₂-rock interaction at elevated temperatures under hydrothermal conditions</td>
<td>CO₂ saturated H₂O-granodiorite interaction at 120 and 200°C</td>
</tr>
<tr>
<td>Pruess, K.</td>
<td>2006</td>
<td>Enhanced geothermal systems (EGS) using CO₂ as working fluid - A novel approach for generating renewable energy with simultaneous sequestration of carbon</td>
<td>Thermodynamic analysis, static fluid T-P well profile, mass and heat extraction rates at different reservoir temperatures</td>
</tr>
<tr>
<td>Pruess, K., et al.</td>
<td>2006</td>
<td>On The Feasibility Of Using Supercritical CO₂ As Heat Transmission Fluid In An Engineered Hot Dry Rock Geothermal System</td>
<td>Thermodynamic analysis, static fluid T-P well profile, fracture flow simulation</td>
</tr>
<tr>
<td>Pruess, K.</td>
<td>2007</td>
<td>Enhanced Geothermal Systems (EGS): Comparing Water And CO₂ As Heat Transmission Fluids</td>
<td>Thermodynamic analysis, static fluid T-P well profile, mass and heat extraction rates at 200°C and 50 MPa reservoir condition</td>
</tr>
<tr>
<td>Pruess, K. &amp; Spycher, N.</td>
<td>2007</td>
<td>ECO2N: A fluid property module for the TOUGH2 code for studies of CO₂ storage in saline aquifers</td>
<td>Equation of state for CO₂-brine mixture for geosequestration application</td>
</tr>
<tr>
<td>Kaieda, H., et al.</td>
<td>2008</td>
<td>Experimental Study on CO₂ injection Into HDR Geothermal Reservoir</td>
<td>Calcite precipitation is observed after CO₂ saturated water was injected in a geothermal well</td>
</tr>
<tr>
<td>Author/s</td>
<td>Year</td>
<td>Title</td>
<td>Remarks</td>
</tr>
<tr>
<td>--------------------------------</td>
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<td>----------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Pruess, K.</td>
<td>2008</td>
<td>On production behaviour of enhanced geothermal systems with CO₂ as working fluid</td>
<td>2D reservoir simulation at different reservoir pressures, 3D effects at 20 MPa and 200°C reservoir conditions</td>
</tr>
<tr>
<td>Atrens, A. D., Gurgenci, H., &amp; Rudolph, V.</td>
<td>2009</td>
<td>CO₂ Thermosiphon for Competitive Geothermal Power Generation</td>
<td>Formulation for 1D analysis and economics</td>
</tr>
<tr>
<td>Atrens, A. D., Gurgenci, H., &amp; Rudolph, V.</td>
<td>2009</td>
<td>Exergy Analysis Of A CO₂ Thermosiphon</td>
<td>1D thermodynamic and exergy analysis</td>
</tr>
<tr>
<td>Kaieda, H., et al.</td>
<td>2009</td>
<td>Field Experiments For Studying On CO₂ Sequestration In Solid Minerals At The Ogachi HDR Geothermal Site, Japan</td>
<td>Dry-Ice (solid CO₂)-H₂O-rock interaction field experiments</td>
</tr>
<tr>
<td>Atrens, A. D., Gurgenci, H., &amp; Rudolph, V.</td>
<td>2010</td>
<td>Electricity generation using a carbon-dioxide thermosiphon</td>
<td>1D thermodynamic and exergy analysis</td>
</tr>
<tr>
<td>Pruess, K. &amp; Spycher, N.</td>
<td>2010</td>
<td>Enhanced Geothermal Systems (EGS) with CO₂ as Heat Transmission Fluid - A Scheme for Combining Recovery of Renewable Energy with Geologic Storage of CO₂</td>
<td>2D reservoir simulation at different reservoir pressures, 3D effects at 20 Mpa and 200°C reservoir conditions</td>
</tr>
<tr>
<td>Agarwal, V., &amp; Anderson, B. J.</td>
<td>2010</td>
<td>An Integrated Model to Compare Net Electricity Generation for CO₂- and Water-Based Geothermal Systems</td>
<td>CO₂ versus H₂O at constant mass flow rate</td>
</tr>
<tr>
<td>Sugama, T., Eckler, L., &amp; Butcher, T.</td>
<td>2010</td>
<td>Carbonation of Rock Minerals by Supercritical Carbon Dioxide at 250°C</td>
<td>Water/mineral paste were exposed to scCO₂ for 3 days in an autoclave.</td>
</tr>
<tr>
<td>Sugama, T., Eckler, L., &amp; Butcher, T.</td>
<td>2011</td>
<td>Susceptibility of Granite Rock to scCO₂/Water at 200°C and 250°C</td>
<td>Water/mineral paste were exposed to scCO₂ for up to 42 days.</td>
</tr>
</tbody>
</table>
Chapter 3: Theoretical Background

This chapter presents the principles and theories used in this research. The first section explains the principles and laws of thermodynamics applicable to geothermal power plants. The thermodynamic analyses of process components are clarified, and the thermodynamics of different geothermal plant configurations such as flash steam (single and dual) and binary cycles are presented. The concept of exergy and its analysis are also explained.

Basic concepts on the flow of fluid in porous and fractured media are presented in the second section. Terminologies used in geothermal reservoir engineering are defined. Simple pressure-transient and lumped-parameter models for reservoir simulations are presented, and the concept of dual porosity model is explained.

The last section briefly reviews the chemistry of fluid-rock interaction applicable to geothermal systems. Kinetics and equilibria of mineral dissolutions in geothermal fluids are briefly discussed.

3.1 Thermodynamics of Geothermal Power Plant Cycles

The analysis of any power plant cycle requires the knowledge of the thermodynamic properties of the working fluid. These fluid properties include pressure ($p$, Pa), temperature ($T$, K), enthalpy ($h$, kJ/kg), entropy ($s$, kJ/kg K), and specific volume ($v$, m$^3$/kg) or its alternate, which is density ($\rho$, kg/m$^3$).

The working fluid can exist in gas, liquid, or a mixture of both gas and liquid phases. To express the thermodynamic properties of a two-phase fluid (i.e. mixture of liquid and gas phase of the same working fluid), it is necessary to determine the saturated properties of both liquid and gas phases. It is common practice to put $l$ or $g$ subscripts to denote liquid and gas saturation properties, respectively.
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The thermodynamic properties of mixture are calculated as

\[ h = (1-x) h_l + x h_g \]  
\[ s = (1-x) s_l + x s_g \]  
\[ h = (1-x) v_l + x v_g \]

(3.1)  
(3.2)  
(3.3)

where \( x \) is the mass fraction of the gas phase in the mixture.

Several thermodynamic processes are considered when analysing geothermal power plants. These include isentropic, isenthalpic, isobaric, and heat exchange processes.

In the isentropic process, the entropy \( s \) is kept constant. Ideally, fluid expansion in the turbines and fluid compression in the compressors and pumps are isentropic processes. The working fluid does work in this process and ideally with no losses to the environment or fluid.

Enthalpy is kept constant in a isenthalpic process. There is no change in the energy content of the fluid in this process; therefore, no work or heat is delivered or consumed from the environment. An example of an isenthalpic process is the expansion in a throttling valve.

Pressure is kept constant in an isobaric process. This is an ideal assumption used in flash vessels or during boiling and is appropriately used where almost no pressure changes take place in a process.

Heat exchange is where heat is transferred to or from the fluid. Enthalpy and entropy of the fluid can both change during the heat exchange process. Pressure may remain constant or with negligible changes, but this is not necessarily true for all processes.

In any process component calculations, mass and energy balances must always be satisfied. In a steady state condition, the sum of mass or energy flow into a component must be equal to the mass or energy flow out of the component. The flow of energy has three forms: (1) energy of the flowing fluid, (2) work performed or consumed, and (3) heat exchange into or from the component.
Chapter 3: Theoretical Background

3.1.1 Components of Geothermal Power Systems

The main components of a geothermal power system are subsurface components such as geothermal injection and production wells as well as above surface components such as the power plant. Depending on the nature of the geothermal reservoir, the power plant itself can be of either direct flash or binary configuration. The main features of geothermal wells are briefly discussed in the present section while flash and binary power plant concepts are discussed in the proceeding sections.

The well is usually the starting point of any geothermal power plant thermodynamic analysis. The well delivers the geofluid from the underground reservoir to the surface facilities; in the case of re-injection wells, it is the reverse. The well is composed of several casings with varying diameters. A typical deep steam well is made of a 50.8 cm (20") anchor casing, a 34 cm (13-3/8") surface casing, a 24.45 cm (9-5/8") production casing, and a 22.23 cm (8-3/4") open hole or a 18.73 cm (7-3/8") slotted liner (Figure 3.1).

Three important thermodynamic properties characterise a geothermal well:

1. Wellhead pressure - the pressure at the top of the well. Usually the wellhead pressure is controlled using a throttling valve.

2. Mass flow - the amount of fluid flowing from the well which is highly dependent on the properties of geothermal reservoir and well parameters (diameter, inclination, roughness, etc.)

3. Fluid saturation temperature at the bottom of the well, which is used to calculate the energy content of the hydrothermal fluid

As an approximation, it is assumed that the flow of hydrothermal fluid in the well is isenthalpic, which means that there is no heat loss/gain from the well to the surroundings. If one assumes that the well is fed by liquid water at the bottom of the well, the hydrothermal fluid may flash along the well and a two-phase flow may develop. The quality of the two-phase fluid can be calculated using wellhead pressure and either temperature of the liquid at the bottom of the well or known enthalpy of the
well by following an isenthalpic line on the temperature-entropy ($T$-$s$) diagram as shown in Figure 3.2.

*Figure 3.1: Typical Dry Steam Geothermal Well (DiPippo, 2008b).*
3.1.2 Thermodynamics of Flash Cycles

The main components of a flash type power plant are essentially the flash vessel(s), turbine(s), and condenser. The flash vessel allows the separation of liquid water and steam from a two-phase flow commonly encountered in hydrothermal fluid gathering facilities. It is based on the idea of creating vortex where the pressure is minimal at the centre and the centrifugal force separates the heavier water droplets from the steam. The two-phase fluid is introduced tangentially to enhance vortex creation (Figure 3.3). Ideally, the liquid water and steam exiting the vessel is saturated (Figure 3.4).

Figure 3.2: T-s diagram showing isenthalpic lines starting from saturated water.
Figure 3.3: Schematic Diagram of a Flash Vessel or Steam Separator (Pallson, H., lecture notes).
Figure 3.4: T-s diagram of the process during flashing and separation of water and steam inside a flash vessel.

The turbine extracts energy from flowing fluids and converts it to do useful work. Potential and kinetic energy of the flowing fluids are captured using several physical phenomena. Impulse turbines change the direction of flow of high velocity fluids while reaction turbines create torque as the pressure changes and the fluid expands (Figure 3.5). Impulse turbine follows Newton's Second Law while the reaction turbine follows Newton's Third Law. Most of the turbines used in geothermal power plants use a combination of impulse and reaction turbine principles.

Ideally, the thermodynamic process in a turbine is isentropic. However, in real systems, that is not the case (Figure 3.6). Instead, the turbine has a parameter called turbine efficiency (isentropic efficiency), which is defined as

$$\eta_s = \frac{W}{W_s} = \frac{h_1 - h_2}{h_1 - h_{2s}}$$

(3.4)
On the other hand, the quality of the fluid exiting the turbine can be calculated as

\[ x_2 = \frac{h_2 - h_i}{h_{2s} - h_i} \]  

(3.5)

and the actual entropy of the fluid at the turbine outlet is calculated as

\[ s_2 = (1 - x_2)s_i + x_2s_g \]  

(3.6)

where \( W \) is real power output, \( W_i \) is ideal power output when the process is isentropic, \( h_i \) is enthalpy of the fluid at the turbine inlet, \( h_2 \) is enthalpy of the fluid at the outlet, \( h_{2s} \) is ideal enthalpy of the fluid at the turbine outlet, \( s_i \) is entropy of saturated water, and \( s_g \) is entropy of saturated steam.

Figure 3.5: Schematic diagram summarising the differences between impulse and reaction turbines (Wikipedia Commons).
Chapter 3: Theoretical Background

Figure 3.6: $T$-$s$ diagram of a steam turbine process.

A condenser is used to convert the vapour exiting the turbine into liquid because it has negligible compressibility and is easier to pump than vapour. The condenser essentially extracts the latent heat of vaporisation of vapour to condense it to saturated or sub-cooled liquid. The condenser can be a direct-contact where the vapour is mixed with the cooling liquid or a non-contact where heat exchanger is used to extract heat from the vapour.

The flash cycle geothermal power plant uses steam coming from flash vessels to drive the turbine to generate electricity. The hydrothermal fluid coming from the production wells are allowed to "flash" or boil in a vessel at a lower pressure than its saturation pressure. The steam is then used to drive the turbine while the separated water is flashed again in a much lower pressure to produce more steam (dual-flash or multi-flash steam cycles) or injected back into the reservoir.

A $T$-$s$ diagram of a single flash steam cycle using a 250°C saturated liquid aquifer temperature generated using EES is shown in Figure 3.7. Two-scenarios can be drawn using a single flash cycle:

1. A single flash back pressure cycle (Figure 3.8) where there is no condenser after the turbine and the turbine outlet is vented to the atmosphere.
2. A single flash with condenser (Figure 3.9). It is obvious from the $T$-$s$ diagram that the single flash with condenser is more efficient because it has a lower outlet temperature (lower condenser pressure).

The effective condensation pressure of the single flash back pressure is the atmospheric pressure while the typical working pressure of a condenser is 12 kPa or lower.

Figure 3.10 shows the plot of power output per 1 kg/s flow of saturated liquid aquifer fluid versus optimum separation pressure. It shows that the optimum separation pressure is highly dependent on the aquifer temperature (or to the enthalpy of the fluid entering the flash vessel). The power output increases with higher aquifer temperature and the maximum power output is reached at optimum separation pressure which also increases with higher aquifer temperature. This can be explained by the fact that the power output is a function of mass flow (affected by the steam quality at the separation pressure) and the enthalpy change from the turbine inlet (the same as the vapour enthalpy at the separation pressure) and turbine outlet (constraint by the condenser pressure). In a given aquifer temperature, as the separation pressure increases, the enthalpy change across the turbine increases, but the steam quality at the flash vessel decreases (in other words, the amount of steam going to the turbine decreases) or vice versa. One constraint that must be considered during optimisation is that the steam quality of the turbine outlet must not be lower than 85%. The simulation used 12 kPa for condenser pressure.

Figure 3.11 shows the power output per 1 kg/s flow of 250°C saturated liquid aquifer fluid (1085 kJ/kg enthalpy) and steam quality at the turbine outlet as function of separation pressure. At low separation pressures, the power output increases with separation pressure mainly due to an increase in enthalpy change across the turbine and high steam fraction at the flash vessel. After reaching the optimum separation pressure, the power output starts to decline due to a significantly smaller steam fraction at the flash vessel. The steam quality at the turbine outlet decreases with increasing separation pressure. It can be seen that the maximum power output of 101.8 kW is obtained at the optimum separation pressure of 429 kPa while the steam quality at the turbine outlet is 87%.
**Figure 3.7:** $T-s$ diagram of a single flash steam cycle with 85% turbine (isentropic) efficiency.

**Figure 3.8:** Schematic diagram of a single flash back pressure cycle.
**Figure 3.9:** Schematic diagram of a single flash cycle with condenser.

**Figure 3.10:** Optimisation of power output per 1 kg/s flow versus separation pressure of single flash cycle at different saturated liquid aquifer temperatures.
In a dual-flash steam cycle, high temperature hydrothermal fluids are flashed in a high pressure flash vessel (HPFV), and the separated water is flashed again in a low pressure flash vessel (LPFV). The steam separated from the HPFV is fed into a high pressure turbine while the steam from the LPFV is fed into the lower stages of the same turbine (Figure 3.12) or into a secondary low pressure turbine (Figure 3.13).

To maximize the power output for dual flash cycle, the optimum high and low separation pressures must be established. Figure 3.14 shows a $T-s$ diagram of an optimised dual flash process for 250°C saturated liquid aquifer fluid. The maximum power output is 128 kW per 1 kg/s of fluid, and the optimum high and low separation pressures are 1004 kPa and 151.5 kPa, respectively.
Figure 3.12: Schematic diagram of a dual flash cycle with one turbine.

Figure 3.13: Schematic diagram of a dual flash cycle with two turbines.
Chapter 3: Theoretical Background

Figure 3.14: T-s diagram of an optimised dual flash steam cycle for 250 °C saturated liquid aquifer.

Table 3.1 shows the maximum power output of single and dual flash steam cycles for a range of saturated liquid aquifer temperatures calculated at optimum separation pressure/s. These values were obtained assuming 85% turbine efficiency, 12 kPa condenser pressure, and negligible pumping power requirements. As Table 3.1 shows, the dual flash cycle consistently gives higher maximum power outputs compared with the single flash cycle.

Table 3.1: Maximum power output of single flash and dual flash steam cycles for given saturated liquid aquifer temperatures

<table>
<thead>
<tr>
<th>Liquid Aquifer Temp, °C</th>
<th>Single Flash Cycle</th>
<th>Dual Flash Cycle</th>
<th>Dual Flash Cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max Power</td>
<td>Separ. Pressure</td>
<td>Max Power</td>
</tr>
<tr>
<td></td>
<td>kW</td>
<td>kPa</td>
<td>kW</td>
</tr>
<tr>
<td>200</td>
<td>57</td>
<td>209</td>
<td>73</td>
</tr>
<tr>
<td>225</td>
<td>78</td>
<td>301</td>
<td>98</td>
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<tr>
<td>250</td>
<td>102</td>
<td>429</td>
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<td>275</td>
<td>131</td>
<td>607</td>
<td>163</td>
</tr>
<tr>
<td>300</td>
<td>165</td>
<td>860</td>
<td>204</td>
</tr>
</tbody>
</table>
3.1.3 Thermodynamics of Organic Rankine Cycles

Binary power plants use the Organic Rankine Cycle (ORC) as their working principle. The hydrothermal fluid or geofluid is used to heat a secondary (working) fluid that drives the turbine to generate electricity (Figure 3.15). The secondary fluid has a lower boiling point than water at ordinary atmospheric condition. Usually, a binary cycle power plant is used for low to moderate temperature geothermal resources.

Several organic fluids can be used as secondary fluid in a binary plant including isopropane, isobutane, isopentane, n-hexane, n-heptane, and many refrigerants. The choice of fluid depends on the temperature of the geofluid, the maximum power that can be generated, the amount of circulation fluid, and other considerations (toxicity, flammability, and other hazards). In some instances, the superheat vapour exhaust of the turbine has enough energy content to justify installation of recuperator/heat exchanger to pre-heat the circulation fluid (Figure 3.16) for more efficient operation.

Table 3.2 shows the theoretical maximum power output of an ORC with a recuperator using two different organic fluids per 1 kg/s flow of 250°C saturated liquid aquifer fluid. It also shows the optimum pump pressure, organic fluid mass circulation flow per 1 kg/s of geofluid, operating vapour temperature, and geofluid outlet temperature. It shows that using the refrigerant R123 (3-2-dichloro-1,1,1-trifluoroethane) gives a maximum power of 183 kW and isopentane at 175 kW. However, the circulation mass flow of R123 is high compared with isopentane requiring larger heat exchangers. Also, R123 is an ozone-depleting compound (chlorofluorocarbon), and its use may be limited. For practicality, these maybe the reasons why isopentane is the typical organic fluid used in ORC. Turbine efficiency is assumed at 85% and pump efficiency at 75%. The condenser pressure is assumed at 101.325 kPa or at atmosphere condition.

The T-s diagram of an ORC with isopentane as the organic fluid is shown in Figure 3.17. The green line represents the ORC process with theoretical maximum power output where the red line demonstrates the optimised ORC process. It can be seen that the optimised process, unlike the maximum power output process, avoids the two-phase region upon expansion of the fluid in the turbine. The unique shape of the saturation
curves of some organic fluids such as isopentane allows for formation of superheat vapour during fluid expansion in the turbine, thus avoiding problems associated with the two-phase flow. The optimised process has a vapour temperature of 175°C, producing 172 kW per 1 kg/s of geofluid at 250°C and 2,800 kPa circulation pressure.

**Figure 3.15**: Schematic diagram of a binary plant using ORC.

**Figure 3.16**: Schematic diagram of a binary plant using ORC with recuperator.
Table 3.2: Theoretical maximum power output of an ORC using different organic fluids from 1 kg/s 250 °C saturated liquid aquifer fluid

<table>
<thead>
<tr>
<th>Organic Fluid</th>
<th>Pump Pressure, kPa</th>
<th>Vapour Temp., °C</th>
<th>Fluid Outlet Temp., °C</th>
<th>Fluid Mass Circulation, kg/s</th>
<th>Turbine Power Output, kW</th>
<th>Pump Power, kW</th>
<th>Net Power, kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>isopentane</td>
<td>3292</td>
<td>185.7</td>
<td>65.99</td>
<td>1.789</td>
<td>187.7</td>
<td>12.4</td>
<td>175.3</td>
</tr>
<tr>
<td>R123</td>
<td>2786</td>
<td>178.6</td>
<td>46.23</td>
<td>4.04</td>
<td>195.2</td>
<td>12.12</td>
<td>183</td>
</tr>
</tbody>
</table>

Figure 3.17: T-s diagram of an ORC with isopentane as the organic fluid.

### 3.1.4 Exergy Analysis

The thermodynamic performance of a geothermal system is usually assessed in terms of the first and second law of thermodynamics. The second law performance is often expressed as a function of availability or “exergy,” which is discussed later in this section.

In geothermal applications, the system is open and assumed in steady state. The equation governing the first law of thermodynamics of open system and steady state condition is given by (DiPippo, 2008d)

-25 -20 -1.8 -1.6 -1.4 -1.2 -1.0 -0.8 -0.6 -0.4 -0.2
0 25 50 75 100 125 150 175 200

T [°C]

s [kJ/kg-K]
\[ \dot{Q} - \dot{W}_s = -\sum_{i=1}^{n} m_i (h_i + \frac{v_i^2}{2} + gz_i) \] (3.7)

where \( \dot{Q} \) is the rate of heat transfer from the surroundings (positive when heat flows from the surroundings to the system), \( \dot{W}_s \) is the mechanical work transferred (positive when work is done by the system to the surroundings), \( m_i \) is the mass flow of fluid through inlets or outlets, \( h_i \) is the specific enthalpy of the fluid, \( v_i \) is the velocity of the fluid, \( z_i \) is elevation of the fluid, \( g \) is the local gravitational constant, and \( i \) is an index used for inlets and outlets of the system.

The steady state condition and conservation of mass requires that the summation of mass into and out of the system is equal to zero.

For open and steady state systems, the Second Law of thermodynamics can be written as (DiPippo, 2008d)

\[ e_p = -\sum_{i=1}^{n} m_i s_i - \int_{t_1}^{t_2} \frac{1}{T} \frac{dQ}{dt} \] (3.8)

where \( e_p \) is the entropy production, \( s_i \) is the specific entropy of the fluid, \( T \) is the absolute temperature, and \( t \) is time.

In a perfectly reversible process and when the fluids being discharged is in thermodynamic equilibrium with its surroundings, entropy production is zero, and the equation (3.8) becomes

\[ 0 = -\sum_{i=1}^{n} m_i s_i - \int_{t_1}^{t_2} \frac{1}{T} \frac{dQ}{dt} \] (3.9)

Exergy is the maximum useful work that can be produced from a given system in a given environment. Unlike energy, exergy is not conserved. Exergy can be created or destroyed. It is based on the Second Law of thermodynamics. Exergy is also governed and grounded on the First Law of thermodynamics, which states that energy is conserved when it changes into different forms.
The exergy of flowing fluid in an open and steady state system from state 1 to state 2 can be derived using the two equations of the first and second laws to give

\[ e_m = h_2 - h_1 - T_0 (s_2 - s_1) + \frac{(v_2^2 - v_1^2)}{2} + g(z_2 - z_1) \]  

(3.10)

where \( e_m \) is the specific exergy of the flowing fluid and 0 denotes dead state or a condition where the fluid is in thermodynamic equilibrium with its surroundings.

The exergy transferred during heat transfer in an open and steady state system is governed by Carnot efficiency and is calculated as

\[ e_o = (1 - \frac{T_0}{T})Q \]  

(3.11)

The exergy transferred by doing mechanical work when there is no dissipation of energy is the amount of work itself.

\[ e_w = W \]  

(3.12)

### 3.2 Geothermal Reservoir Engineering

In order to fully understand the context of geothermal reservoir engineering, several terminologies must be defined for consistency. Geothermal field is generally used to point to a specific geographic location where a geothermal system exists. Geothermal field refers to the geographic name of a specific geothermal resource. The system that defines the subsurface hydrology and geology associated with a geothermal field is the geothermal system specific to that location. Geothermal reservoir is where hot permeable rock and hot fluid exist, and commercial exploitation of the geothermal field is feasible. The geothermal reservoir is only part of the geothermal system while hot impermeable rock without fluid is not considered to be part of the geothermal reservoir (Grant & Bixley, 2011a).

The flow of fluid in the subsurface rock is divided into two paths: through the rock body or rock matrix (matrix flow) and through rock fractures (fracture flow). The amount of
void space and its physical characteristic control fluid flow in the rock (Glassley, 2010b).

The total fraction of void space (pore) in the rock mass is its porosity

\[ \phi = \frac{\text{total pore volume}}{\text{total volume}} \]  

(3.13)

Some of the pores in the rock are closed, that is the fluid inside is bound to the rock and does not participate in the bulk fluid motion. Assuming all pores are filled with fluid, effective porosity is defined as

\[ \phi_e = \frac{\text{volume of fluid free to move}}{\text{total fluid volume in storage}} \]  

(3.14)

The flow of fluid in porous media was experimentally quantified by Henry Darcy in the mid 1800s and defined permeability in the following relationship

\[ q = -\frac{k}{\mu} A \nabla(P) \]  

(3.15)

where \( q \) is the flux (volumetric flow per unit area, \( \text{m}^3/\text{m}^2/\text{s} \)), \( k \) is the permeability (\( \text{m}^2 \)), \( \mu \) is the dynamic viscosity of the fluid (\( \text{kg}/\text{m}\cdot\text{s} \)), \( A \) is the cross-sectional area of the fluid flow (\( \text{m}^2 \)), and \( \nabla(P) \) is the pressure gradient including that due to gravity.

The relationship between porosity and permeability was first quantified by Kozeny (1927) and modified by Carman (1937, 1956), which is known as the Kozeny-Carman Equation

\[ k = \frac{\phi^3}{(1-\phi)^2} \frac{(5S_A)^2}{(5S_A)^2} \]  

(3.16)

where \( S_A \) is the surface area of the pore spaces per unit volume of solid.

Hydraulic conductivity, \( K \), is a measure of the fluid's ability to flow in the pore spaces and is related to permeability from Darcy's equation

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where \( \rho g \) is the specific weight of the fluid.

### 3.2.1 Simple Reservoir Models

The complexities of geothermal reservoirs can be grouped into two: (1) spatial variation and (2) variation in the thermodynamic properties of the fluid. Idealisations from these give rise to two simplified reservoir models. Pressure transient models simplify the fluid and investigate the variation in the spatial characteristics of the reservoir. Lumped-parameter models simplify the geometry and probe the thermodynamics of fluid and rock (Grant & Bixley, 2011b).

The simplest pressure transient model is a vertical cylindrical well penetrating a uniform horizontal aquifer with infinite radial extent.

\[
K = \frac{k}{\mu} (\rho g)
\]  
(3.17)

**Figure 3.18:** Basic pressure-transient model of a vertical well ((Grant & Bixley, 2011b).

Using Darcy's Law in the radial form

\[
q_r = -\frac{k}{\mu} \frac{\partial p}{\partial r}
\]  
(3.18)

and conservation of mass
and assuming that changes in compressibility and viscosity can be ignored, withdrawing at constant rate, \( q \), then

\[
\Delta P = P - P_0 = -\frac{q\mu}{4\pi kh} E_1 \left( \frac{\phi kr^2}{4kt} \right)
\]  

(3.20)

where \( E_1(x) = \int_x^\infty \frac{1}{y} e^{-y} dy \)

For small values of \( x \) or long time

\[
E_1(x) \approx -\ln(x) - \gamma
\]

where \( \gamma \) is equal to 0.5772 or the Euler's constant, Equation 3.20 becomes

\[
P - P_0 = -\frac{q\mu}{4\pi kh} \left\{ \ln(t) + \ln \left( \frac{4k}{\phi kr^2} \right) - 0.5772 \right\}
\]

(3.21)

Equation 3.21 can be used to determine permeability-thickness, \( kh \), when pressure is plotted against time on a semi-logarithmic scale.

The simplest lumped-parameter model is a single box containing homogenous rock and fluid, where fluid is withdrawn and recharged from external sources. Let \( M \) be the mass withdrawn, \( M_r \), the mass recharged in the box, and \( V \), the volume of the box. Conservation of mass is as follows

\[
S_M \frac{dp}{dt} + M - M_r = 0
\]

(3.22)

\[
S_M = V*\phi*\rho*c
\]

(3.23)

where \( S_M \) is the mass stored or released per unit change in pressure.

Then assuming that the recharge is proportional (\( \alpha \)) to the total pressure drop in the box
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\[ M_r = \alpha(P_0 - P) \]  
(3.24)

and combining Equations 3.22 and 3.24 yields

\[ M = \alpha(P_0 - P) - S_M \frac{dp}{dt} \]  
(3.25)

Withdrawing mass at a constant rate, \( W \), from \( t = 0 \) is an exponential approach to equilibrium,

\[ P_0 - P = \frac{M}{\alpha} (1 - e^{\frac{t}{\tau}}) \]  
(3.26)

where \( \tau = \frac{S_M}{\alpha} \) is the relaxation time.

For short times, the pressure drops linearly with time

\[ P_0 - P = \frac{M \times t}{S_M} \]  
(3.27)

and at time significantly greater than the relaxation time, the pressure stabilises dependent on the balance between withdrawal and recharge

\[ P_0 - P \approx \frac{M}{\alpha} \quad t >> \tau. \]  
(3.28)

Below are the definitions of some of the other terminologies used in reservoir engineering. Fluid compressibility, \( c \), is defined as the changes in fluid volume per unit change in fluid pressure

\[ c = -\frac{1}{V} \left( \frac{dV}{dp} \right)_{h=constant} \]  
(3.29)

Reservoir storage coefficient is the volume of fluid stored or released per unit pressure change. Storativity, \( S \), is the storage coefficient per unit area. In a horizontal fluid flow in the aquifer, the storage coefficient per unit area is called transmissivity, \( T \)
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\[ S = \phi * c * h \]  
\[ T = \frac{k}{\mu} \]

(3.30)  
(3.31)

where \( h \) is the uniform reservoir thickness.

In fractured rocks, fracture aperture \((a)\) and fracture spacing have the greatest effect on the movement of fluid. Fracture permeability is defined (Bear, 1993) as

\[ k_f = \frac{a^2}{12} \]

(3.32)

Transmissivity of a fracture is defined (Glassley, 2010b) as

\[ T_f = (\rho * g)(\frac{a^2}{12}) a = \frac{\rho * g * a^3}{12\mu} \]

(3.33)

Barometric efficiency describes the effect of atmospheric pressure on the water level (or any fluid) in the aquifer. The water level decreases when barometric pressure increases and vice versa. Barometric efficiency depends on the compressibility of the fluid and aquifer.

\[ \beta = \left| \frac{dh_p}{dp_a / \rho g} \right| \]

(3.34)

where \( dh_p \) is the change in fluid level and \( dp_a \) is the change in atmospheric pressure.

3.2.2 Dual Porosity Model

The double medium or double porosity theory is first applied to groundwater flow by Barenblatt, Zheltov, and Kochina (1960) and in the petroleum reservoir by Warren and Root (1963). The idealised block structure of the fractured rock is depicted in Figure 2.19. The pressure equation for flow in the fracture is (Grant & Bixley, 2011b):
\[ \frac{k_f}{u} \nabla^2 P_f = \phi_f c_f \frac{\partial P_f}{\partial t} + Q \]  \hspace{1cm} (3.35)

\[ Q = \frac{k_m}{u} \frac{P_f - P_m}{L_2} \]  \hspace{1cm} (3.36)

\( Q \) is the volume transfer from the matrix to the fracture per unit reservoir volume and is assumed to be proportional to the pressure difference between fracture \((P_f)\) and matrix \((P_m)\) pressures in a quasi-steady flow; \( L \) is the representative block dimension and \( u \) is the mass flux density. Conservation of mass gives

\[ Q = \phi_m c_m \frac{\partial P_m}{\partial t} \]  \hspace{1cm} (3.37)

\[ \text{Figure 3.19: Idealised dual porosity model (Grant & Bixley, 2011b).} \]

Several limitations must be observed from the above equations. First, the matrix is assumed single phase. Second, the uniform block size distribution is unrealistic because fractures are random and create very large block size distributions within the reservoir.
Thirdly, the transfer function used does not represent the transient flow of fluid between the matrix and fracture.

The limitations brought by the dual porosity model have been addressed by numerical simulators. The Multiple Interacting Continua (MINC) formulation of Pruess and Narasimham (1985), and Pruess, Oldenburg, and Moridis (1999) explicitly computed for fluid properties in the matrix treated as nested layers in the TOUGH2 reservoir simulator (Figure 3.20). In MINC, each block in the matrix is subdivided further into nested layers where fluid mass and heat transfer are computed explicitly.

![Figure 3.20: Multiple interacting continua. Modified after (K. Pruess & Narasimham, 1985).](image)

### 3.3 Chemistry of Fluid-Rock Interactions

The chemistry of fluid interacting with the rock in a geothermal reservoir is important in many aspects of geothermal exploration, development, and utilisation. The chemical composition of the geofluid is used to infer the natural state of the reservoir during the early stages of geothermal exploration. The changes in the chemical composition of the geofluid is used to infer physical and chemical processes occurring during the exploitation of the resource such as peripheral water inflow and mixing, boiling and
phase-segregation, return of re-injected separated water into the production zone of the reservoir, and other processes. The chemistry of the geofluid gives an indication on mineral dissolution or precipitation and can be used to infer how it will affect the reservoir performance, scaling, and corrosion-erosion in the well and surface pipelines.

In a naturally occurring geothermal system, water is the fluid that interacts with the surrounding rocks. Water is considered a universal solvent because of its abundance and polarity. Its electrical polarity is due to the orientation of the two hydrogen atoms covalently bonded to the central oxygen atom. It is capable of dissolving a large array of organic and inorganic minerals. Geothermal waters solute content ranges from low to very high salinity comparable to sea water.

Geothermal fluids may be classified into two classes: primary and secondary fluids. Primary fluids are found in the roots of a geothermal system and possibly composed of water of meteoric in origin, seawater, and magmatic volatiles. Secondary fluids are formed by the mixing of the primary fluids with surface and/or ground water (Arnorsson, Stefansson, & Bjarnason, 2007).

### 3.3.1 Basic Chemistry Concepts

In chemistry, the minimum number of chemical constituents that can describe a system is called components. The system can be made of different phases such as mineral (solid), aqueous, and gaseous. Solid phases are the mineral entities in the system while liquid and gas phases are any homogeneous mixture of different chemical components described in the system.

Consider the hypothetical salt mineral AB, which dissociates to components A$^+$ and B$^-$

$$AB \leftrightarrow A^+ + B^-$$  \hspace{1cm} (3.38)

At equilibrium, the rate at which AB dissociates to A$^+$ and B$^-$ is equal to the rate at which the two components combine to form the mineral AB. The law of mass action states that at any given set of conditions, the product of activities, $a$, of the products of reaction divided by the product of activities of the reactants is constant, $K$. 

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\[
\frac{[a_A a_B]}{a_{AB}} = K
\]  

(3.39)

Ideally, activities of the chemical species are equal to their molality or the number of moles per kg solvent. The plot of log of equilibrium constant should change linearly with temperature. However, non-ideal behaviour of charged ions in aqueous solution makes the plot of Log \( K \) versus temperature non-linear. The activities of mineral phases are equal to 1.0 by convention.

Activity coefficients, \( \gamma \), is introduced to correct the measured concentration of a chemical species so that the mass action law for a given reaction is satisfied. It is a factor multiplied to the molality of the chemical species.

\[
(\gamma_A m_A) (\gamma_B m_B) = K
\]  

(3.40)

For dilute solutions, the activity coefficients are close to 1, and for most purposes, the molality of the chemical species can be used for calculations. Concentrations less than that of seawater level are considered dilute (Glassley, 2010a).

One measure that determines the state of a reaction is affinity, \( A \).

\[
A = RT \ln \frac{Q}{K}
\]  

(3.41)

where \( R \) is the universal gas constant (8.314 J/mole-K), \( T \) is temperature in Kelvin, and \( Q \) is the activity quotients of the applicable reaction.

Affinity is zero when the reaction is in thermodynamic equilibrium. Mathematically, affinity is equal to Gibbs free energy of a reaction

\[
A = G_{\text{products}} - G_{\text{reactants}} = (H_{\text{products}} - H_{\text{reactants}}) - T(S_{\text{products}} - S_{\text{reactants}})
\]  

(3.42)

\[
\Delta_r G = \Delta_r G^\circ + RT \ln Q
\]  

(3.43)
where $\Delta G$ is the Gibbs free energy of the reaction, $\Delta G'$ is the standard Gibbs free energy of the reaction, and $Q$ is the reaction quotients.

At equilibrium, Gibbs free energy is zero and $Q = K$.

$$\Delta G' = -R T \ln K$$  \hfill (3.44)

The equilibrium constant at different temperatures can be calculated using the van't Hoff equation given the enthalpy of reaction ($\Delta H$)

$$\ln K_2 - \ln K_1 = \frac{\Delta H}{R} \left( \frac{1}{T_1} - \frac{1}{T_2} \right)$$  \hfill (3.45)

### 3.3.2 Kinetics of Reaction

The thermodynamic state of a system (temperature and pressure), surface area exposed to the fluid, and amount and the composition of the starting materials determine how fast a reaction will reach equilibrium. The rate at which a given reaction progresses is called kinetic rate of reaction.

The dissolution or precipitation rate of minerals taking into account the different factors affecting it can be expressed in the general form (Glassley, 2010a) as

$$R = S_A \times k \times T_{fac} \times \alpha \times \Phi \times \Pi a_i \times (1 - \frac{Q}{K})^\omega$$  \hfill (3.46)

where $R$ is the rate (mole/s), $S_A$ is the effective surface area exposed to the fluid (cm$^2$), $k$ is the far from equilibrium rate constant (mole/cm$^2$-s), $T_{fac}$ is the temperature correction factor for $k$ (usually an Arrhenius function), $\alpha$ is the power function that accounts for changes in the rate close to equilibrium conditions, $\Phi$ is a function that modifies the rate for precipitation relative to that for dissolution that is based on experimental data, $\Pi a_i$ is an account for the dependence of the rate on the activities of specific components in solution (often this is mainly a reflection of the activity of the hydrogen ion, H$^+$), and $\omega$ is power dependence based on experimental data that accounts for the particular dissolution or precipitation mechanism.
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However, there is no sufficient data available to use in Equation 3.45, and as a result, various simplifications to the rate laws have been proposed. In PHREEQC, the rate equation used is

\[
\frac{dm_k}{dt} = c_{i,k} R_k
\]  

(3.47)

\[
R_k = r_k A_0 \left( \frac{m_k}{m_{ok}} \right)^n
\]  

(3.48)

where \( c_{i,k} \) is the stoichiometric coefficient of the species \( i \), \( R_k \) is the overall reaction rate for the substance/mineral \( k \) (mol/kg-s), \( r_k \) is specific rate (mol/m²/s), \( A_0 \) is initial surface area of the solid, \( V \) is the amount of the solution (kg), \( m_{ok} \) is the initial amount of the solid mineral (moles), \( m_k \) is the amount of the solid mineral at any given time (moles), and \( \left( \frac{m_k}{m_{ok}} \right)^n \) is the factor that accounts for changes in \( \frac{A_0}{V} \) (for uniformly dissolving spheres and cubes, \( n = 2/3 \)).

The specific rate expression has various forms (Parkhurst & Appelo, 1999) and depends on the available experimental data from which it is derived. As an example, the specific rate equation for calcite mineral is approximated by

\[
r_{\text{calcite}} = (k_1 a_{H^+} + k_2 a_{CO_2} + k_3 a_{H_2O}) \left[ 1 - \left( \frac{IAP}{K_{\text{calcite}}} \right)^{2/3} \right]
\]  

(3.49)

where \( IAP \) is the ion activity product, \( a_i \) is the activity of the species \( i \), and \( k_1, k_2, \) and \( k_3 \) are coefficients determined by Plummer, Wigley, and Parkhurst (1978) as function of temperature.

A simple expression for the specific rate can be used when no other information is available. An example is the use of saturation ratio \( \left( \frac{IAP}{K_k} \right) \) in
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\[ r_k = k_k \left( 1 - \left( \frac{IAP}{K_k} \right)^\sigma \right) \]  
(3.50)

where \( k_k \) is an empirical constant, and \( \sigma \) are the coefficients related to the stoichiometry of the reaction.

In other cases, the saturation index, \( \log \left( \frac{IAP}{K_k} \right) \) can be used for the specific rate

\[ r_k = k_k \sigma \log \left( \frac{IAP}{K_k} \right) \]  
(3.51)

### 3.3.3 Dissolution and Alteration of Minerals

Natural weathering of alkali-feldspar, Albite, and K-felspar to kaolinite is given in the following reactions,

\[
2\text{NaAlSi}_3\text{O}_8 + 2\text{CO}_{2(aq)} + 11\text{H}_2\text{O} \rightarrow \text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 + 2\text{Na}^+ + 2\text{HCO}_3^- + 4\text{H}_4\text{SiO}_4
\]
(3.52)

\[
2\text{KAlSi}_3\text{O}_8 + 2\text{CO}_{2(aq)} + 11\text{H}_2\text{O} \rightarrow \text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 + 2\text{K}^+ + 2\text{HCO}_3^- + 4\text{H}_4\text{SiO}_4
\]
(3.53)

The above reaction can also be expressed as

\[
2\text{NaAlSi}_3\text{O}_8 + 2\text{H}^+ + 9\text{H}_2\text{O} \rightarrow \text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 + 2\text{Na}^+ + 4\text{H}_4\text{SiO}_4
\]
(3.54)

\[
2\text{KAlSi}_3\text{O}_8 + 2\text{H}^+ + 9\text{H}_2\text{O} \rightarrow \text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 + 2\text{K}^+ + 4\text{H}_4\text{SiO}_4
\]
(3.55)

Most often, these two end-members of alkali feldspar co-exist and can be expressed as an ion exchange reaction

\[
\text{NaAlSi}_3\text{O}_8 + \text{K}^+ \leftrightarrow \text{KAlSi}_3\text{O}_8 + \text{Na}^+
\]
(3.56)

This implies that, at equilibrium, the activity ratio \( \text{Na}^+ / \text{K}^+ \) is constant and can be used as a geothermometer to indicate the temperature of the solution in contact with the alkali-
feldspar. However, other minerals may participate in the cation exchange, and how fast they reach thermodynamic equilibrium affects the activity ratio Na⁺/K⁺.

The log $K$ temperature equations for dissolutions of some minerals are shown in Table 2.3.
### Table 3.3: $\log K$ temperature equation of some mineral dissolutions valid up to 300 $^\circ$C and saturation pressure, modified after Angcoy (2010)

<table>
<thead>
<tr>
<th>Reaction</th>
<th>$\log K$ (T in K)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. $\text{cal} + 2H^+ \leftrightarrow \text{Ca}^{2+} + H_2O_1 + CO_{2\text{aq}}$</td>
<td>$\log K = -68.271 + \frac{4385.24}{T} - 0.007525T + 25.856\log T$</td>
</tr>
<tr>
<td>2. $\text{wol} + 2H^+ + H_2O_1 \leftrightarrow \text{Ca}^{2+} + H_4SiO_4^0$</td>
<td>$\log K = -127.096 + \frac{8151.38}{T} - 0.02981T + 49.282\log T$</td>
</tr>
<tr>
<td>3. $\text{gro} + 4H^+ + 8H_2O_1 \leftrightarrow 3\text{Ca}^{2+} + 2\text{Al(OH)}_4^\text{-} + 3H_4SiO_4^0$</td>
<td>$\log K = -517.662 + \frac{17623.7}{T} - 0.14343T + 203.808\log T$</td>
</tr>
<tr>
<td>4. $\text{pre} + 10H_2O_1 \leftrightarrow 2\text{Ca}^{2+} + \text{Fe(OH)}_4^\text{-} + 2\text{Al(OH)}_4^\text{-} + 3H_4SiO_4^0 + 2OH^-$</td>
<td>$\log K = 833.95 - \frac{25642.8}{T} + 0.5035T - 2.941\times10^{-4}T^2 - 369.297\log T$</td>
</tr>
<tr>
<td>5. $\text{czo} + 12H_2O_1 \leftrightarrow 2\text{Ca}^{2+} + 3\text{Al(OH)}_4^\text{-} + 3H_4SiO_4^0 + OH^-$</td>
<td>$\log K = 36.052 - \frac{6854.79}{T} + 0.13236T - 1.3749\times10^{-4}T^2 - 33.508\log T$</td>
</tr>
<tr>
<td>6. $\text{epi} + 12H_2O_1 \leftrightarrow 2\text{Ca}^{2+} + \text{Fe(OH)}_4^\text{-} + 2\text{Al(OH)}_4^\text{-} + 3H_4SiO_4^0 + OH^-$</td>
<td>$\log K = 893.547 - \frac{27077.4}{T} - 0.54124T - 3.022\times10^{-4}T^2 - 398.38\log T$</td>
</tr>
<tr>
<td>7. $\text{mag} + 4H_2O_1 \leftrightarrow \text{Fe}^{2+} + 2\text{Fe(OH)}_4^\text{-}$</td>
<td>$\log K = 949.951 - \frac{24258.2}{T} + 0.51474T - 2.402\times10^{-4}T^2 - 417.136\log T$</td>
</tr>
<tr>
<td>8. $\text{pyr} + 2H^+ + H_2\text{aq} \leftrightarrow \text{Fe}^{2+} + 2H_2\text{Saq}$</td>
<td>$\log K = -1.397 - \frac{461.3}{T} - 0.0009128T + 1.626\log T$</td>
</tr>
<tr>
<td>9. $\text{pyrr} + 2H^+ \leftrightarrow \text{Fe}^{2+} + H_2\text{Saq}$</td>
<td>$\log K = -3.043 + \frac{1579.06}{T} + 0.001987T + 0.12\log T$</td>
</tr>
<tr>
<td>10. $\text{qtz} + 2H_2O_1 \leftrightarrow H_4SiO_4^0$</td>
<td>$\log K = -34.188 + \frac{197.47}{T} - 5.851\times10^{-6}T^2 + 12.245\log T$</td>
</tr>
</tbody>
</table>

A geo-indicator based on Na-K-Mg-Ca concentrations was proposed by Giggenbach (1988) to assess the geothermal fluid's degree of equilibrium attainment in a thermodynamically stable mineral system. The Na-K, K-Mg, and K-Ca pair equilibria are governed respectively by

\[
\log \left( \frac{C_{Na}}{C_K} \right) = 1.75 - \frac{1390}{T} \tag{3.57}
\]

\[
\log \left( \frac{C_K^2}{C_{Mg}} \right) = 14.0 - \frac{4410}{T} \tag{3.58}
\]

\[
\log \left( \frac{C_K^2}{C_{Ca}} \right) = \log f_{CO_2} + 3.0 \tag{3.59}
\]

where \( C_i \) is the concentration of \( i \) in mg/kg, \( f \) is the fugacity, and \( T \) is the temperature in Kelvin.

These subsystems are used to create a graphical technique to evaluate the geothermal fluids (Figure 3.21) and assess deep temperature and partial CO\(_2\) pressure.
Figure 3.21: Na-K-Mg ternary diagram for geothermal fluid assessment.
Chapter 4: One and Two-Dimensional Combined Reservoir and Power Plant Cycle Modelling for EGS

This chapter presents 1D/2D integrated reservoir-wellbore and power plant modelling for engineered geothermal systems. Thermodynamic and power cycle analyses of CO₂ and H₂O based EGS are assessed, and the results are compared under similar operating conditions.

The numerical methods used are presented in sections 4.1 and 4.2. The calculation is performed in two steps namely, (1) calculation of fluid flow and exergy from the injection well to the production well, and (2) calculation of power generation potential.

The effect of operational and reservoir parameters on mass circulation, heat extraction rates, exergy, and power potential are examined in Sections 4.3.1 to 4.3.4. These parameters include injection pressure, injection temperature, well pipe roughness, well to well distance, well configuration, reservoir depth (pressure), reservoir temperature, and reservoir permeability. The effect of using a multi-diameter well casing design is also analysed and compared with the reference single diameter design. Comparison analyses are performed for given injection pressures since the injection pressure is often the variable that is set or pre-determined when assessing reservoir or well performance.

The modelling presented in this chapter does not consider the influence of the reservoir temperature changes due to heat depletion over the lifetime of the reservoir and hence only represent a snapshot of the entire reservoir-power production process. Also, 3D and acceleration effects are ignored for simplicity.
4.1 Wellbore and Reservoir Flow Modelling

In general, an iterative procedure was implemented to solve the mass and energy balances from the top of the injection well to the bottom of the production well using the Engineering Equation Solver (EES) software. The governing equations and systematic approach for the model development are presented in this section.

The schematic diagram of the 1D wellbore and 1D reservoir simulated in this study is presented in Figure 4.1. As Figure 4.1 shows, the major components of the flow for the so-called energy harvesting process include the injection well, the reservoir, and the production well. In this process, the cold fluid is injected at the top of the injection well, passing through the injection well and the reservoir, with the hot fluid reaching the surface at the top of the production well. For the modelling presented in this chapter, typical dimensions for each component were selected; a depth of 5000 m for the wells and a length of 1000 m for the reservoir were considered. To simulate the flow-through the system, a pressure balance calculation was performed. It was found that the total pressure drop from the injection well and across the reservoir up to the bottom of the production well (i.e. $P_{\text{inj}} - P_{\text{res}}$) is equal to the sum of the injection wellbore frictional pressure losses and reservoir pressure losses minus the fluid static pressure. The overall pressure balance for the flow passing through the injection well and the reservoir hence was expressed as

$$P_{\text{inj}} = P_{\text{res}} + \Delta P_{f,\text{well}} + \Delta P_{f,\text{res}} - \sum \rho g \Delta z$$  (4.1)

where $P_{\text{inj}}$ is the injection pressure, $P_{\text{res}}$ is the reservoir pressure at the bottom of the production well, $\Delta P_{f,\text{well}}$ is the wellbore frictional losses, $\Delta P_{f,\text{res}}$ is the total reservoir pressure losses, $\Delta z$ is the depth increment of the wellbore, $\rho$ is the density, and $g$ is the gravitational constant, 9.81 m/s$^2$.

Assuming adiabatic conditions and negligible acceleration effects, the wellbore flow and Darcy 1D reservoir flow were described by the following equations (Atrens, Gurgenci, & Rudolph, 2009)
\[ \Delta P_{f, \text{well}} = \sum \left[ f \frac{8\pi^2 \Delta z \dot{m}^2}{\rho D^5} \right] \]  

\[ f = \left[ -1.8 \log \left( \frac{6.9}{R_e} + \left( \frac{\varepsilon}{3.7D} \right)^{1.11} \right) \right]^{-2} \]  

\[ \Delta P_{f, \text{res}} = \sum \left[ \frac{\dot{m} \mu \Delta L}{\rho \kappa A} \right] \]  

Where \( \Delta L \) is the length increment of the reservoir, \( \dot{m} \) is the mass flow rate, \( f \) is the Darcy-Weisbach friction factor, \( R_e = \frac{\rho V D}{\mu} = \frac{4\dot{m}}{\mu \pi D} \) is the Reynolds number, \( \varepsilon \) is the pipe roughness, \( D \) is the pipe diameter, \( \kappa \) is the homogeneous permeability, \( \mu \) is the viscosity, \( A \) is the area of the fluid flow in the reservoir, and the rest is the same as defined above.

Equation 4.2 represents the summation of pipe wall frictional losses integrated over the height of the well with \( \Delta z \) depth increments. The friction factor used is the Haaland equation (Equation 4.3), which is an approximation of the Colebrook equation.

The summation of reservoir fluid pressure losses from the bottom of the injection well to the bottom of the production well (i.e. reservoir length) is represented by equation 4.4. The equation is based on one dimensional Darcy fluid flow in homogeneous formation with constant fluid viscosity. It was assumed that fluid properties across the reservoir distance \( \Delta L \) are constant. In addition, the reservoir parameter \( kA \), permeability multiplied by cross-sectional area of the flow, was assumed constant and adapted the value used by Atrens et al. (2009), which was obtained through calibrations of past EGS trials. The quantitative measure of a porous media to allow fluid to flow though it is referred to as permeability from location to location even within the same geographic reservoir.

Using similar approach, production pressure at the wellhead \( (P_{\text{prod}}) \) was derived by performing a pressure balance over the height of the production well.
\[ P_{\text{prod}} = P_{\text{res}} - \sum \rho g \Delta z - \Delta P_{\text{f,well}} \]  \hspace{1cm} (4.5)

**Figure 4.1**: Schematic diagram of a Darcy 1D reservoir flow model flow.

### 4.1.1 Wellbore Flow Calculation

To model the pressure-temperature profile and hence the flow through the wellbore, the wellbore height was divided into small elements with a length of \( \Delta z \). The elements are connected by nodes: The top most node represents the wellhead while the bottom most node represents the bottom of the well.

In the injection well, the calculation starts at the wellhead where injection temperature and injection pressure are initially given. The initial enthalpy \( h_0 \) of the fluid, density \( \rho_n \), viscosity, friction factor, and wellbore frictional losses \( \Delta P_{f_n} \) along the wellbore element length are calculated using the given injection temperature \( T_n \) and injection pressure \( P_n \). The above parameter are then used to calculate pressure \( P_{n+1} \) and temperature \( T_{n+1} \) in the next node as shown in Equations 4.6 and 4.7.

\[ P_{n+1} = P_n + \rho_n g \Delta z_n - \Delta P_{f_n} \]  \hspace{1cm} (4.6)

\[ T_{n+1} = T(P_{n+1}, h_0) \]  \hspace{1cm} (4.7)
The calculation process was repeated in sequence along the entire height of the wellbore. In the production well, the calculation starts at the bottom of the well using the given reservoir temperature and reservoir pressure.

\[ T_n = T_{\text{init}} + (n - 0.5)\Delta T \]  \hspace{1cm} (4.8)

**Figure 4.2:** Discretisation of the wellbore height into small elements with $\Delta z$ length. The diagram also shows how the nodes (i.e. 1, 2, 3, 4..n, n+1) were indexed.

**4.1.2 1D Reservoir Flow Calculation**

Simulation of the flow through the reservoir relies on the prediction of fluid properties particularly temperature and pressure profile. For simplicity, the temperature profile of the fluid traversing the reservoir was assumed to be linear with the temperature between the calculated fluid temperature at the bottom of the injection well and the reservoir temperature at the bottom of the production well. The temperature at any point between the bottom of the injection and production wells was therefore predicted using Equation 4.8
\[
\Delta T = \frac{(T_{res} - T_{int})}{n}
\]

(4.9)

where \( n \) is the number of calculation intervals, \( T_{int} \) is the injection well bottom-hole temperature, \( T_{res} \) is the reservoir temperature, and \( P_{int} \) is the injection well bottom-hole pressure.

Using an approach similar to that of the wellbore flow, the length of the reservoir was divided into small elements. The fluid pressure distribution in the reservoir was then determined using the calculated pressure \((P_{int})\) and temperature \((T_{int})\) at the bottom of the injection well

\[
P_{n+1} = P_{int} - \sum_{0}^{n} \frac{\dot{m} \mu \Delta L}{\rho_n \kappa A}
\]

(4.10)

The fluid viscosity \( \mu(T_n, P_n) \) and density \( \rho(T_n, P_n) \) were calculated as functions of fluid temperature and pressure using correlations incorporated in the Engineering Equation Solver (EES) software.

### 4.1.3 2D Reservoir Flow Calculation

One-dimensional (1D) reservoir flow simulation presented in Section 4.1.2 only considers the axial distribution of the fluid properties specifically the pressure ignoring its radial distribution. Therefore, a 2D model of the reservoir was developed to provide a more realistic fluid pressure distribution through the reservoir, specifically from the injection well to the production well. For the 2D simulation of the reservoir, typical reservoir characteristics (similar to those of the Soultz HDR Project) were used. Specifically, the reservoir was considered to have a permeability of 50.0 \( \times 10^{-15} \) \( \text{m}^2 \) and reservoir thickness of 300 m. The schematic diagram of the 2D reservoir is presented in Figure 4.3.

The injection well was considered a line source which disturbed the pressure distribution in the reservoir in the radial direction (Kjaran & Eliasson, 1983). Darcy's law can be expressed as
\[
\frac{\partial P}{\partial r} = \frac{\mu \dot{V}}{2\pi \kappa L_R}
\]  
(4.11)

where \( \dot{V} \) is the volumetric flow rate, \( L_R \) is the reservoir thickness, and \( r \) is the distance from the well.

Assuming steady state with constant pressure boundary condition, the reservoir pressure loss from the injection well face, \( r_W \), and the production well located at distance, \( r_R \), and converting volumetric flow rate to mass flow rate was approximated by

\[
\Delta P_{res} = \frac{\mu n}{2\pi \rho \kappa L_R} \ln \left( \frac{r_W}{r_R} \right)
\]  
(4.12)

Using an approach similar to that of the wellbore flow calculation, the distance from the injection well to the production well was divided into small elements. The pressure drawdown at the end of the \( n \)th element in the reservoir with a linear fluid temperature profile from the injection to the production well was calculated as

\[
\Delta P_{f,\text{res}} = \sum_{n=0}^{n} \frac{\mu_n \dot{m}_n}{2\pi \rho_n \kappa L_R} \ln \left( \frac{r_{n+1}}{r_n} \right)
\]  
(4.13)

The pressure at any point between the injection well and production well (\( P_{n+1} \)) given the bottom-hole injection pressure (\( P_{\text{inj}} \)) can then be obtained using Equation 4.14.

\[
P_{n+1} = P_{\text{inj}} - \sum_{n=0}^{n} \frac{\mu_n \dot{m}_n}{2\pi \rho_n \kappa L_R} \ln \left( \frac{r_{n+1}}{r_n} \right)
\]  
(4.14)
4.1.4 Simulation Inputs for Wellbore and Reservoir Flows

The pressure balances in the 1D/2D reservoir and 1D wellbore flows were solved using Engineering Equation Solver (EES). EES calculates thermodynamic properties of carbon dioxide using the fundamental equation of state developed by Span and Wagner (1996), and viscosity and thermal conductivity are based on the work by Vesovic, Wakeham, Sengers, Watson, and Millat (1990). EES gives thermodynamic properties of water using the 1995 Formulation for the Thermodynamic Properties of Ordinary Water Substance for General and Scientific Use issued by The International Association for the Properties of Water and Steam (Wagner & Pruss, 2002).

The system was defined by the reservoir pressure at the bottom of the production well, injection pressure, and injection temperature at the surface. Table 4.1 lists the calculation parameters used in the 1D/2D EGS simulation.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Length</td>
<td>700 and 1000 m</td>
</tr>
<tr>
<td>Reservoir Temperature</td>
<td>200, 225 and 250°C</td>
</tr>
<tr>
<td>Permeability-area, kA</td>
<td>2.1x10^{-9} m^4</td>
</tr>
<tr>
<td>Reservoir Pressure, $P_{res}$</td>
<td>29.43 and 49.05MPa</td>
</tr>
<tr>
<td>Reservoir thickness</td>
<td>300 m</td>
</tr>
</tbody>
</table>
## 4.1.5 Heat Extraction Rate

Heat extraction rates were calculated based on the enthalpy change of the fluid from the injection well to the production well and mass flow rate (Pruess, 2008) as shown by the following expression

\[
\dot{Q} = m(h - h_0)
\]

(4.15)

## 4.1.6 Exergy

The exergy or the availability of the geofluid was calculated based on the exergy created or destroyed due to change in fluid enthalpy. Exergy is not a state function, so choosing the initial and final states as well as the path of the fluid are critical for its assessment. In this integrated modelling approach, the initial and final states of the fluid are the injection and production wellhead conditions of the fluid, respectively.

The total exergy generated from EGS is dominated by exergy associated with change in enthalpy expressed as

\[
e_H = (h - h_0) - T_0(s - s_0)
\]

(4.16)

where \(e_H\) = exergy associated with change in enthalpy, \(h\) is the specific enthalpy, \(s\) is the specific entropy, and \(T\) is temperature in Kelvin.

The subscript 0 denotes initial conditions; in our case, it is the condition at the surface of the injection well.
4.2 Power Cycle Modelling

The computational modelling approach of a CO₂ thermosiphon power plant for the CO₂ based EGS as well as a binary plant for H₂O based EGS are presented in this section (note that the thermosiphon concept is not applicable to water). The process flow diagram for the CO₂ thermosiphon power cycle is shown in Figure 4.4. As the process diagram illustrates, the cold dense liquid CO₂ is injected in the injection well, passes through the reservoir where it is heated into a lighter hot supercritical CO₂ (scCO₂), and then flows up in the production well. The scCO₂ then passes through the valve and the strainer before entering the turbine. The hot scCO₂ expands in the turbine (producing mechanical work/power), exits the turbine, and then passes through the condenser where it is converted to cold liquid CO₂ before being injected into the injection well. The process is repeated, establishing the CO₂ thermosiphon power cycle.

The strainer’s function is to remove solid particles and condensates carried by the geofluid. The valve is usually fully open and can be used as a throttling valve if production pressure control is opted. The scCO₂ fluid expansion in the turbine generates the mechanical work/power. The fluid expansion is realistically done in multi-stage turbines, but for calculation simplification purposes, the turbine in the power cycle modelling in this chapter is represented by a single stage turbine with an overall efficiency ($\eta_t$). The fluid condensation process in the condenser is assumed isobaric, and the pressure loss between the condenser and the injection wellhead is assumed negligible; hence, the turbine outlet pressure is approximated to be equal to the injection pressure at the wellhead.

The coupled reservoir and wellbore modelling from Section 4.1.1 to 4.1.3 provide predictions of the mass flow rate ($\dot{m}$), production pressure ($P_{prod}$), and temperature ($T_{prod}$). These parameters were used to perform the power cycle simulation. For the modelling of the power cycle, the elevation between the production wellhead and turbine inlet was considered to be negligible and the heat losses in the pipe ignored.

Based on the above assumptions, the enthalpy at the turbine inlet ($h_2$) can be given as
\[ h_2 = h(T_{\text{prod}}, P_{\text{prod}}) \]  

(4.17)

For an ideal process, the fluid expansion in the turbine follows an isentropic path

\[ s_{3s} = s_2 = s(T_{\text{prod}}, P_{\text{prod}}) \]  

(4.18)

The ideal fluid enthalpy at the turbine outlet was then determined using the injection pressure \((P_3)\) and ideal fluid specific entropy \((s_{3s})\)

\[ h_{3s} = h(s_{3s}, P_3) \]  

(4.19)

For a given turbine efficiency \((\eta_t)\), the actual specific fluid enthalpy at the turbine outlet \((h_3)\) was obtained using Equation 4.19

\[ h_2 - h_3 = \eta_t (h_2 - h_{3s}) \]  

(4.20)

The temperature and actual entropy at the turbine outlet were calculated using enthalpy and pressure at the turbine outlet

\[ T_3 = T(h_3, P_3) \]  

(4.21)

\[ s_3 = s(h_3, P_3) \]  

(4.22)

The turbine power \((W_t)\) was then calculated as

\[ W_t = \dot{m}(h_2 - h_3) \]  

(4.23)

Assuming that the condensation process was isobaric (i.e. \(P_4 = P_3\)), the condenser duty \((W_{\text{cond}})\) was determined based on the enthalpy change in the heat exchanger

\[ P_4 = P_3 \]  

(4.24)

\[ W_{\text{cond}} = \dot{m}(h_4 - h_3) \]  

(4.25)

where \( h_4 = h(T_4, P_4) \).
For the H₂O based EGS power cycle modelling, the binary power cycle was selected. That is because the earlier analysis of the power output of different geothermal power plant configurations presented in Chapter 3 showed that a binary plant produces more power than single or dual steam flash cycle. In H₂O based EGS cycle, water is not directly used to drive the turbine. Instead, the thermal energy is transferred from hot H₂O fluid to a secondary working fluid (hydrocarbons or other refrigerants) to drive the turbine. A circulating pump is also used to pump the secondary fluid to the desired inlet turbine pressure. The process flow diagram of the binary plant for H₂O based EGS is presented in Figure 4.5. The process diagram shows that the hot H₂O from the production well passes through the first heat exchanger (evaporator/vaporiser) where the heat exchange boils the secondary working fluid at the set circulating pump pressure. The H₂O exiting the vaporiser then enters a second heat exchanger (heater) where it heats the secondary working fluid to the saturation temperature corresponding to the circulating pump pressure. The cold spent H₂O exiting the heater is then pumped into the injection well. The hot secondary working fluid vapour exiting the vaporiser enters the turbine where its expansion generates mechanical work/power. The secondary fluid still contains significant amounts of energy at low pressure as it leaves the turbine, and to recover that energy, it passes through a heat exchanger (recuperator) where it pre-heats the cold high pressure secondary fluid at liquid state pumped from the condenser. After passing through the recuperator, the low pressure secondary fluid is then passed through the condenser to fully condense it to saturated liquid before pumping at high pressure. The high pressure secondary fluid exiting the recuperator then passes through the heater, completing the cycle, and the process is repeated.
Figure 4.4: Process flow diagram of a typical CO₂ thermosiphon power cycle.

Figure 4.5: Process flow diagram of a typical binary plant for H₂O based EGS.
Assuming the heating (in the heater) and evaporation process (in the evaporator) of the secondary working fluid are carried out with negligible pressure losses, the following relationship holds true at a the given circulation pump pressure ($P_b$)

$$P_b \approx P_c \approx P_d \approx P_e$$  \hspace{1cm} (4.26)

The subscript $b$, $c$, $d$, and $e$ refer to the thermodynamic state of secondary working fluid exiting the high pressure pump, recuperator, heater, and vaporiser, respectively (please refer to Figure 4.5 for the corresponding notations).

The isopentane exiting the heater was assumed saturated liquid ($x = 0$). That is

$$T_d = T_{\text{sat}}(P_b)$$  \hspace{1cm} (4.27)

$$h_d = h(P_b, x = 0)$$  \hspace{1cm} (4.28)

The isopentane exiting the vaporiser was considered to be saturated vapour ($x = 1$)

$$T_e = T_d = T_{\text{sat}}(P_b)$$  \hspace{1cm} (4.29)

$$h_e = h(P_b, x = 1)$$  \hspace{1cm} (4.30)

The temperature and the enthalpy of the H$_2$O exiting the vaporiser were predicted assuming a pinch temperature of 5°C (i.e. the minimum temperature difference between the fluids streams in the heat exchanger was assumed 5°C).

$$T_2 = T_d + 5$$  \hspace{1cm} (4.31)

The numeric subscript 2 refers to the thermodynamic state of H$_2$O exiting the evaporator

$$h_2 = (T_2, P_{\text{prod}})$$  \hspace{1cm} (4.32)

The enthalpy of the H$_2$O from the production well ($h_1$) was then calculated using production temperature ($T_{\text{prod}}$) and pressure ($P_{\text{prod}}$)
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\[ h_i = h(T_{prod}, P_{prod}) \]  \hspace{1cm} (4.33)

Mass and energy balances were performed on the vaporiser obtaining the following relationship

\[ \dot{m}_w (h_i - h_2) = \dot{m}_i (h_e - h_d) \]  \hspace{1cm} (4.34)

where \( \dot{m}_w \) is the mass flow rate of the water from the production wells, and \( \dot{m}_i \) is the isopentane mass circulation flow rate.

In an ideal expansion process, the entropy at the turbine inlet is equal to that of the turbine outlet

\[ s_{fs} = s_e = s(T_e, P_a) \]  \hspace{1cm} (4.35)

where the subscript \( fs \) refers to the ideal thermodynamic state of the secondary working fluid exiting the turbine.

The ideal enthalpy at the turbine outlet was determined from the given condenser pressure \( (P_a) \) and calculated fluid entropy

\[ h_{fs} = h(P_a, s_{fs}) \]  \hspace{1cm} (4.36)

For a given turbine efficiency \( (\eta_a) \), the actual specific fluid enthalpy, temperature, actual entropy at the turbine outlet and gross power \( (W_t) \) from turbine were calculated using the following relationships

\[ h_e - h_f = \eta_f (h_e - h_{fs}) \]  \hspace{1cm} (4.37)

\[ T_f = T(h_f, P_a) \]  \hspace{1cm} (4.38)

\[ s_s = s(h_f, P_a) \]  \hspace{1cm} (4.39)

\[ W_t = \dot{m}_i (h_e - h_f) \]  \hspace{1cm} (4.40)
Assuming that the fluid in the outlet stream of the condenser was saturated liquid, the pump power requirement \( W_p \) can be solved using the following relationship

\[
W_p = \dot{m}_i (h_b - h_a)
\]  

The symbols were defined as

\[
h_a = h(P_a, x = 0)
\]  

\[
s_a = s(P_a, x = 0)
\]  

\[
s_{bi} = s_a
\]  

\[
h_{bi} = h(P_b, s_a)
\]  

\[
h_b - h_a = \eta_p (h_{bs} - h_a)
\]  

where \( \eta_p \) is the pump efficiency.

The following equations describe the operation of the recuperator assuming that the pinch is 5°C at the outlet

\[
T_b = T(P_b, h_b)
\]  

\[
T_{g} = T_b + 5
\]  

\[
h_g = h(T_g, P_a)
\]  

\[
h_b - h_i = h_j - h_g
\]  

\[
T_c = T(P_c, h_c)
\]  

The enthalpy and temperature of the H\(_2\)O stream exiting the heat exchanger was obtained by performing mass and energy balance on the heater

\[
\dot{m}_w (h_2 - h_g) = \dot{m}_i (h_d - h_c)
\]
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\[ T_3 = T(P_{\text{prod}}, h_3) \]  

(4.53)

The net power generated from H\(_2\)O based EGS using the binary plant is calculated as turbine power minus pump power for H\(_2\)O injection and pump power for circulation of the secondary working fluid

\[ W_{\text{net}} = W_{\text{turbine}} - W_{\text{pump, injection}} - W_{\text{pump, circulation}} \]  

(4.54)

The predicted net power is the optimum solution computed using EES based on the production pressure and temperature and may not necessarily result to calculated H\(_2\)O temperature exiting the heat exchanger equal to that of the given injection temperature. In this case, it is assumed that the H\(_2\)O exiting the binary plant is further used for other purposes that will reduce its temperature to the given injection temperature.

Power losses in the cooling tower and other parasitic losses are neglected in the calculation of net power.

4.2.1 Simulation Inputs for Power Cycle Modelling

The predicted mass flow rates and the fluid thermodynamic properties at the production wellhead (i.e. production temperature and pressure) from the coupled reservoir and wellbore modelling, and the given injection temperature and injection pressure were the primary simulation inputs used in the power cycle modelling. The simulation inputs for the power cycle modelling were summarised in Table 4.2.
Table 4.2: Simulation inputs for the Power Cycle Modelling.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Binary Plant for H₂O based EGS</th>
<th>CO₂ Thermosiphon Power Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine Efficiency</td>
<td>85%</td>
<td>85%</td>
</tr>
<tr>
<td>Pump Efficiency</td>
<td>70%</td>
<td>70%</td>
</tr>
<tr>
<td>Geofluid mass flow rate</td>
<td>Predicted from wellbore-reservoir flow modelling</td>
<td></td>
</tr>
<tr>
<td>Geofluid Temperature*</td>
<td>Inlet</td>
<td>Predicted from wellbore-reservoir flow modelling</td>
</tr>
<tr>
<td>Geofluid Temperature*</td>
<td>Outlet</td>
<td>Predicted from wellbore-reservoir flow modelling</td>
</tr>
<tr>
<td>Pinch Temperature</td>
<td>5°C</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Pump Circulation Pressure</td>
<td>2.793 MPa</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Condenser Pressure</td>
<td>101.325 kPa</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>

*In case of H₂O based EGS, the predicted values from the wellbore-reservoir modelling are the minimum possible values as the power cycle modelling may result to higher values to obtain the optimum net power.
4.3 Results and Discussion

4.3.1 Optimal Cell Size

A sensitivity analysis was performed to determine the optimum calculation element size for the wellbore and reservoir modelling of fluid mass circulation rate over a range of injection pressures. As Figure 4.3 shows, the percentage difference on the predicted mass flow rates for element sizes of 500 and 100 m is about 10% whereas this difference becomes less than 5% for element sizes of 25 and 100 m. The percentage difference on the predicted mass flow rates between element sizes of 25 m and 10 m is less than 1%. Calculations for both wellbore and reservoir flows, therefore, were carried out with an element size of 25 meters to have accurate but computationally efficient simulation results.

Figure 4.6: Sensitivity of the predicted mass flow rate on the calculation element size.
4.3.2 Power Cycle Temperature-Entropy Diagram

A typical temperature-entropy diagram of a CO₂ thermosiphon power cycle is presented in Figure 4.7. It can be seen that the CO₂ stream is mostly at supercritical conditions except at the injection point (point 4) where it exists as liquid especially at injection temperatures lower than critical $T_c=31.04^\circ$C. For the efficient operation of the CO₂ thermosiphon power cycle, CO₂ must be kept at single phase state during injection at the wellhead (i.e. either as a liquid or as a supercritical fluid); otherwise, “gas lock” in the injection well will prevent it from flowing down into the bottom of the well.

Figure 4.8 presents a typical temperature-entropy diagram for the binary power cycle. For the simulation of the H₂O based EGS binary power plant, isopentane was considered as a typical secondary fluid with circulating pump pressure of 2.8 MPa and corresponding saturated vapour temperature of $T_{sat} = 175^\circ$C. The circulation pump pressure of 2.8 MPa was chosen to avoid the existence of a two-phase fluid during the expansion process in the turbine while maintaining a maximum power output. Pump efficiency was assumed to be 70% (consistent with the typical efficiency of real systems), and condenser pressure was considered to be 101.325 kPa. Figure 4.8 shows that the maximum working temperature (just below the critical point) is $188^\circ$C. However, using this temperature would cross the two-phase region upon expansion in the turbine. The presence of liquid droplets in the turbine may cause erosion problems and early failure of the equipment.

Due to the peculiar shape of its temperature-entropy diagram (the so-called saturation dome), isopentane expands as superheated vapour through the turbine (process $e-f$ in Figure 4.8). If a sufficient amount of heat is still present at the superheated vapour, a recuperator could be used to preheat the high pressure liquid.
4.3.3 Injection Pressure and Temperature

The overall efficiency of any power cycle is strongly affected by the heat sink (i.e. the ambient temperature where the power plant is located). In geothermal exploitation, the rejection temperature directly affects the injection temperature of an EGS. That is because the rejection temperature dictates the allowable minimum injection temperature, i.e. the minimum injection temperature can only be the ambient
temperature. Here, the effect of injection temperature and pressure on the geothermal fluid mass flow rate as well as the pressure losses in wells and reservoir are investigated using the 1D and 2D models developed in Section 4.1. The simulations were performed for a reservoir temperature of 225°C and depth of 5 km, and the well pipe roughness used was 40 µm.

Figure 4.9 shows the effect of injection pressure on the mass flow rate of the geothermal fluid at various injection temperatures. It can be seen that for the CO₂ based EGS plant, the mass flow rate of CO₂ increases with a decreasing injection temperature. Conversely, an increase in H₂O mass flow rate was observed as the injection temperature increased. A comparison of the CO₂ and H₂O based EGS also shows that for the same injection temperatures, the CO₂ mass flow rate is greater than that of H₂O mass flow rate at injection pressures greater than 10 MPa. However, an opposite trend began to emerge as the injection pressure lowered and the injection temperature increased. For example, at an injection temperature of 35°C and injection pressure of 9.5 MPa, the mass flow rate of H₂O was greater at 59 kg/s compared to the 41 kg/s mass flow rate of CO₂. This difference becomes even greater since in practice, the injection temperature for the H₂O based EGS has to be kept near 100°C to avoid the potential problem of scaling caused by mineral precipitation at lower temperatures. For the purpose of completeness, the simulation results for the H₂O based EGS at 100°C is also included in Figure 4.9. Clearly, the higher flow rates mean greater pumping power requirements; therefore, the above analysis could guide us in selecting a more appropriate condition to minimise the plant power consumption.

The general behaviour observed in Figure 4.9 can be explained by the flow transport characteristics of the geothermal fluid as a function of temperature and pressure namely the fluid density and viscosity. The density and kinematic viscosity of CO₂ and H₂O at injection wellbore conditions are shown in Figures 4.10 and 4.11. As Figure 4.10 demonstrates, the change in the density of H₂O as a function of pressure and temperature is negligible while reducing the temperature or increasing the pressure significantly increases the CO₂ density. The plot also shows that the density of CO₂ is lower than H₂O at lower pressures (shallower depth) but increases with increasing
pressure (increasing depth). The average density of CO\textsubscript{2} over the wellbore injection conditions, however, is much lower than that of H\textsubscript{2}O.

Figure 4.11 shows the kinematic viscosity of CO\textsubscript{2} and H\textsubscript{2}O as a function of temperature and pressure conditions. It can be seen that for the examined conditions, the kinematic viscosities of CO\textsubscript{2} and H\textsubscript{2}O decreases as the temperature increases. For CO\textsubscript{2}, however, this reduction in viscosity occurs at a much greater rate than H\textsubscript{2}O. Conversely, pressure seems to have little effect on the kinematic viscosity of both fluids.

Considering that the mass flow rate in the reservoir is inversely related to the fluid kinematic viscosity (the ratio of fluid viscosity to its density), the observed higher mass flow rate of CO\textsubscript{2} compared with H\textsubscript{2}O can therefore be attributed to its lower average kinematic viscosity. For the same pressure gradient in a given reservoir length, the mass flow rate is expected to be higher for fluid with lower kinematic viscosity. Moreover, the increase in CO\textsubscript{2} mass flow rate at lower injection temperature can be attributed to the significant increase in its density.

It should be noted, however, that greater frictional losses are often associated with a greater mass flow rate since the frictional loss is directly proportional to the fluid mass flow rate (Equation 4.2). Figure 4.12 shows the frictional loss of CO\textsubscript{2} and H\textsubscript{2}O over the entire length of the injection wellbore. It can be seen that the frictional loss for both fluids follows similar trends as those of their mass flow rates, with greater frictional losses observed at lower temperatures and higher pressures for CO\textsubscript{2}. As shown in Figure 4.10, the average density of CO\textsubscript{2} over the wellbore injection conditions, however, is much lower than that of H\textsubscript{2}O. This characteristic is believed to be responsible for a greater frictional loss since the frictional loss in the well is inversely proportional to fluid density (Equation 4.2).

The bottom-hole pressure in the injection well was also examined as a function of injection pressure and temperature (Fig 4.13). Figure 4.13 shows that as the injection temperature increases, the bottom-hole pressure decreases for both CO\textsubscript{2} and H\textsubscript{2}O based EGS plants. This is because increasing the temperature lowers the fluid density. Fluid density is directly related to hydrostatic pressure (fluid static pressure), and the
hydrostatic pressure is directly proportional to the bottom-hole pressure; therefore, increasing the fluid temperature reduces the bottom-hole pressure. Also, an increase in the injection pressure led to an increase in the bottom-hole pressure for both EGS systems, with H\textsubscript{2}O based EGS plant overall exhibiting a higher bottom-hole pressure under the same wellbore conditions. The greater bottom-hole pressures exhibited by the H\textsubscript{2}O based EGS plant can be associated with the higher average density of H\textsubscript{2}O relative to the CO\textsubscript{2}. This pressure mainly refers to the hydrostatic pressure and simply means that a column of H\textsubscript{2}O is heavier than CO\textsubscript{2}. The plot also shows that H\textsubscript{2}O bottom-hole pressure is slightly influenced by the injection temperature since H\textsubscript{2}O density dependency on temperature over the conditions tested here is marginal (Fig 4.10). Conversely, CO\textsubscript{2} density is highly dependent on temperature; hence, a change in temperature could significantly influence the bottom-hole pressure.

Figure 4.14 shows the reservoir pressure loss as a function of injection pressure and temperature conditions. Similar trends were observed for both CO\textsubscript{2} and H\textsubscript{2}O based EGS plants whereby reducing the temperature and increasing the pressure increased the reservoir pressure loss. The change in kinematic viscosity as a function of temperature could explain the observed trends. As the fluid passes through the reservoir, its temperature rises. The rise in temperature reduces the kinematic viscosity of the fluid as shown in Figure 4.11. That in turn leads to a decrease in pressure loss along the reservoir since kinematic viscosity is directly proportional to the pressure gradient in the Darcy reservoir flow (Equation 4.4). Overall, however, higher reservoir pressure losses were encountered for the H\textsubscript{2}O based EGS plant compared with the CO\textsubscript{2} based EGS plant (Fig 4.14). That is because CO\textsubscript{2} exhibits a lower average kinematic viscosity for the tested conditions than H\textsubscript{2}O (see Fig 4.11).
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Figure 4.9: Fluid mass flow rate versus injection pressure at different injection temperatures.

Figure 4.10: Density of CO₂ and H₂O versus pressure at various temperatures.
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Figure 4.11: Kinematic viscosity of CO₂ and H₂O versus temperature at various pressures.

Figure 4.12: Injection well frictional loss versus injection pressure at different injection temperatures.
Figure 4.13: Injection well bottom-hole pressure versus injection pressure at different injection temperatures.

Figure 4.14: Reservoir pressure loss versus injection pressure at different injection temperatures.

Figure 4.15 shows the heat extraction rates of CO$_2$ and H$_2$O versus injection pressure at different injection temperatures. It can be seen that the heat extraction rate of CO$_2$ and
H$_2$O increases as the pressure increases. However, the effect of temperature on heat extraction rate does not follow a simple trend as there are two interplaying factors involved in determining the heat extraction rate namely, the fluid mass flow rate and the change in enthalpy. At higher injection temperatures, heat extraction rates of H$_2$O are generally higher than that of CO$_2$. That is because H$_2$O undergoes a greater change in enthalpy compared with CO$_2$. At the reference fluid injection conditions of 25°C and 7.5 MPa and the bottom of the production well conditions of 225°C and 50 MPa, the H$_2$O enthalpy was predicted to be 871 kJ/kg which is much greater than CO$_2$ enthalpy change of 313 kJ/kg (see Figures 4.16 and 4.17).

**Figure 4.15:** Heat extraction rate versus injection pressure at different injection temperatures.
Figure 4.16: Pressure-enthalpy diagram of $H_2O$.

Figure 4.17: Pressure-enthalpy diagram of $CO_2$. 
Figure 4.18 shows the fluid production pressure versus injection pressure at different injection temperatures. The diagonal dashed line in Figure 4.18 represents the condition below at which heat exchange through natural convection (thermosiphon) does not occur. As shown in this figure, H$_2$O is not capable of thermosiphon because its production pressure is always lower than the injection pressures while CO$_2$ thermosiphon is possible at 15 MPa and lower injection pressures. The overall effect of injection pressure was found to be negligible, while the CO$_2$ wellhead production pressure drastically decreased with an increasing injection pressure (Fig 4.18). The behaviour of CO$_2$ at higher injection pressures is mainly due to high frictional losses in the production well (Fig 4.19) which in turn is associated with a high mass flow rate and low fluid density exhibited by CO$_2$ at these conditions (see Figures 4.9 and 4.10, respectively).

The H$_2$O wellhead production temperature was found to be almost independent of the injection pressure and temperature which resulted in having approximately the same temperature as that of the reservoir temperature as shown in Figure 4.20. In the same figure, the CO$_2$ wellhead production temperature was found to decrease with injection pressure, resulting to lower temperatures than the reservoir temperature. The strong dependence of CO$_2$ enthalpy on both pressure and temperature can explain the CO$_2$ temperature change in the well. In adiabatic wellbore flow, the change in CO$_2$ pressure inevitably changes CO$_2$ temperature.

Figure 4.21 shows the total exergy of fluid from the injection wellhead to the production wellhead. The H$_2$O total exergy increases approximately linearly with injection pressure while the CO$_2$ total exergy shows a parabolic trend. The total exergy is an interplay of several factors namely, mass flow rate, change in enthalpy, change in entropy, and rejection temperature (Equation 4.16). For H$_2$O, enthalpy and entropy are not so much affected by pressure; hence, at the same injection temperature, the linear trend showed by H$_2$O is because it follows the mass flow rate trend. In the case of CO$_2$, the enthalpy and entropy are greatly affected by both pressure and temperature. In particular, as the CO$_2$ injection pressure increases, the mass flow rate increases, but the production pressure and temperature decreases which strongly affected the entropy at the
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production wellhead. For CO₂, the parabolic trend of the total exergy with respect to injection pressure is primarily due to the interplay of mass flow rate and entropy change (at the same injection temperature and reservoir condition, the change in enthalpy is the same because of adiabatic flow in the wells). The maximum total exergy in the CO₂ plot corresponds to approximately 17 MW at 15.5 MPa injection pressure and 15°C injection temperature. Moreover, the H₂O total exergy increases with the injection temperature while the CO₂ total exergy decreases with the injection temperature similar to the mass flow rate trends. This is because at higher injection temperatures, the kinematic viscosity of H₂O increases therefore increasing the mass flow rate while CO₂ density decreases significantly, decreasing mass flow rate due to higher frictional losses in the injection well.

It can be seen that at 15°C injection temperature and injection pressure lower than 13.5 MPa, CO₂ has a total exergy comparable to that of H₂O. This is only because of the very high CO₂ mass flow rates at this condition. A closer look at the specific exergy (total exergy/total mass flow rate) reveals that CO₂ has less than half the values of H₂O specific exergy (Fig 4.22) in turn indicating that to get the same amount of power potential, the CO₂ mass flow rate needed is twice that of H₂O.

The power generation potential of CO₂ thermosiphon EGS and H₂O based EGS using a binary plant power cycle is shown in Figure 4.23. It shows that H₂O as geofluid is superior in generating power except at very low injection temperatures. CO₂ has optimum power generation of 7.5 MW, which is comparable to that of H₂O at 15°C injection temperature and 9.5 MPa injection pressure. The CO₂ optimum power generation are ~ 6MW and ~5MW for 25 and 35°C injection temperatures, respectively. H₂O power generation increases almost linearly with the injection pressure and also increases with injection temperature.

The behaviour of CO₂ power generation in Figure 4.23 is consistent with the plot of production pressure versus injection pressure (Fig 4.18). Both plots imply that CO₂ thermosiphon is only possible at certain range of injection pressure in any given injection temperature, providing an operating window where the thermosiphon is
encountered. For example, that it is impractical to inject 25°C CO₂ at 15 MPa and higher pressures.

\[\text{Figure 4.18: Fluid production pressure of fluid versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.}\]
Figure 4.19: Production well frictional loss versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.20: Fluid production temperature versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.
Figure 4.21: Total exergy versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.22: Fluid specific exergy created from injection wellhead to the production wellhead versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.
Figure 4.23: Power generation versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

4.3.4 Wellbore Flow

The fluid flow in a channel is predominantly influenced by its channel geometry, surface roughness of the channel wall, and the distance. In this section, the effect of the well surface roughness, well geometry and well to well distance on mass flow rates, total exergy, and power generation were examined. Another reason for studying the influence of well surface roughness on the power generation process is that precipitation of minerals on the wall surface during injection/production of geothermal fluid is quite common, altering the well wall roughness and in turn affecting the process efficiency and power generation capacity. The simulation results presented here were obtained at injection temperature of 25°C, reservoir temperature of 225°C, and well depth of 5 km unless otherwise specified.

To complete our understanding of what is happening on the geothermal fluid while it flows into the well, the pressure and temperature profile in the injection well is presented in here. In adiabatic single phase fluid flow in the injection well, H₂O has almost isothermal flow because of H₂O enthalpy's almost independence on pressure. In comparison, CO₂ temperature well profile is not isothermal because of its enthalpy's
strong dependence on both pressure and temperature. Figure 4.24 shows the temperature and pressure well profile at different injection pressures of 25°C CO₂ injected in a 5km deep well. It clearly shows that CO₂ temperature changes as it flows down the well and the final bottom-hole temperature depends on the final bottom-hole pressure.

**Figure 4.24:** Temperature (left plots, lower X-axis) and pressure (right plots, upper X-axis) well profile at the injection well. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

**Well Wall Roughness**

Figure 4.25 shows the effect of well surface roughness on the mass flow rate of the geothermal fluid. For a normal carbon steel pipe, as the roughness was increased from 40 µm to 400 µm, the CO₂ mass flow rate decreased from 110 to 100 kg/s while the H₂O mass flow rate decreased just by less than 1 kg/s at 9.5 MPa injection pressure. Generally, the decrease in CO₂ mass flow rate is higher than H₂O because of higher CO₂ frictional loss in the well (Fig 4.26, left y-axis). Moreover, as shown in Figure 4.26 (secondary y-axis), the percentage change in frictional loss increases with injection pressure with the CO₂ system consistently exhibiting higher gains in frictional loss compared with H₂O. This is due to CO₂ having lower density than H₂O. Lower fluid density increases well frictional loss (Equation 4.2).
The effect of pipe roughness on total exergy and power generation are also shown in Figures 4.27 and 4.28, respectively. Generally, the total exergy and power generation for the H$_2$O based EGS increased linearly where the trend for the CO$_2$ based EGS was found to be parabolic reaching maximum power generation of ~6 MW using 40 µm roughness. As explained earlier in Section 4.3.3, the trend for H$_2$O total exergy is due to H$_2$O mass flow rate while the trend for CO$_2$ total exergy is influenced by CO$_2$ production pressure and temperature at the wellhead. It can be seen in Figure 4.28 that the CO$_2$ power generation decreases between 6-11% while H$_2$O power generation undergoes negligible changes (about 1-3%). This is consistent with the change in fluid mass flow rate trends shown in Figure 4.25.

**Figure 4.25:** Effect of well wall roughness on the mass flow rate. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.
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Figure 4.26: Well frictional loss versus injection pressure at different well wall roughnesses. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.27: Effect of well wall roughness on total fluid exergy. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.
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Figure 4.28: Effect of well wall roughness on power generation. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Well Geometry

The well geometry studies specifically focused on the effect of well diameter and casing design on the geothermal fluid mass flow rate and power generation of CO₂ and H₂O based EGS. In real systems, geothermal well diameter varies from the wellhead to the bottom of the well. Geothermal well depths of up to 3200m in natural high-temperature hydrothermal systems are common, and geothermal wells with depth of up to 5000 m are starting to emerge as exploration and demonstration projects for EGS. In this study, the effects of varying the well diameter on mass flow rate of the geothermal fluids were investigated. Specifically, the mass flow rate of CO₂ and H₂O in a hypothetical 5000 m geothermal well with varying diameter was compared with a single diameter design with an internal diameter of 0.232 m. The schematic diagram of the hypothetical well with the varying diameter referred to as a multi-diameter design is shown in Figure 4.29. This well is considered a "big hole" because it has a production casing of 29.845 cm (11-3/4") which is bigger than what normally being used in a geothermal well (i.e. 24.45 cm or 9-5/8" casing).
A comparison of the geothermal fluid mass flow rate in wells with single and multi-diameter designs are presented in Figure 4.30. For CO₂ based EGS, the multi-diameter casing design gave slightly higher CO₂ mass flow rates while the H₂O mass flow rate for the H₂O based EGS remained almost unchanged. The percentage rise in CO₂ mass flow rate when the multi-diameter design was used was found to be rather small (about 2-3%). This was despite 25% increase in the well equivalent diameter with the multi-diameter having equivalent internal diameter of 0.291 m and the single diameter design having an internal diameter of 0.232 m. Theoretically (see Equation 4.2), a 75% rise in the geothermal fluid mass flow rate is expected for 25% increase in the well equivalent diameter. This implies that in this coupled wellbore-reservoir flow model simulation, the geothermal fluid mass flow rate is strongly influenced by factors affecting reservoir flow and injection parameters rather than that of wellbore flow (i.e. injection pressure rather than well diameter).

Conversely, the H₂O mass flow rate is driven by the injection pressure and hydrostatic pressure (effect of gravity) and hence was found to be almost independent of the well diameter and its casing design.

![Figure 4.29: Hypothetical 5000 m geothermal well with multi-diameter design.](image)
Figure 4.30: CO₂ mass flow rate comparison between multi and single diameter casing design. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

The operational strategy and the overall footprint of an EGS plant is largely influenced by the distance between the injection and production wells. Figure 4.31 shows the effect of the distance between the wells on the mass flow rate of CO₂ and H₂O at injection pressures ranging between 7-25 MPa, 25°C injection temperature, and well depth of 5 km. Clearly the shorter injection to production well distance of 700 m gave higher geothermal fluid mass flow rates. That is because for the same total reservoir loss, a higher pressure gradient is achieved for a shorter injection to production well distance. The higher reservoir pressure gradient (Fig 4.32) drives the geothermal fluid at a higher mass flow rate through the reservoir. Figure 4.31 also shows that the mass flow rate of H₂O rises at a much greater rate than that of CO₂ as the well to well distance decreases. For example, as well to well distance reduced from 1000 m to 700 m, CO₂ mass flow rate only increased by 15 – 31% while H₂O mass flow rate increased by 35 -39%. This was found to be due to a higher reservoir pressure gradient gain of H₂O compared with CO₂ when the well to well distance was reduced as shown in Figure 4.32. This in turn is caused by high hydrostatic pressure due to higher density of CO₂ than H₂O.
The influence of the distance between the wells on the total exergy and power generation potential are presented in Figure 4.33 and 4.34, respectively. It can be seen that as the distance between the wells reduces from 1000 m to 700 m, the total exergy and power generation potential for H$_2$O based EGS increase. The rise in the total exergy and power generation potential is considered to be due to the increase in the fluid mass flow rate as described earlier. For CO$_2$ based EGS, the total exergy and power generation trend are similar as discussed previously in another section that it has parabolic trend as plotted against injection pressure. Moreover, for the CO$_2$ based EGS, the maximum power generation potential achievable at a given condition was shifted to the lower injection pressure as the distance between the wells was reduced. For example, for a well to well distance of 1000 m, a maximum power of ~6 MW was generated at an injection pressure of 11.5 MPa. As the distance between the wells was reduced by 300 m, a maximum power of 7 MW was generated at a lower injection pressure of 9.5 MPa. This behaviour is believed to be mainly due to achieving a high CO$_2$ mass flow rate at a lower injection pressure as the well to well distance was reduced. However, at a very high mass flow rate at high injection pressures, the high frictional loss in the production well reduces production pressure and temperature, ultimately decreasing the total exergy and power generation potential. This has been explained earlier in another section.
Figure 4.31: The effect of well to well distance on fluid mass flow rate. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.32: Reservoir pressure gradient versus injection pressure at different well to well distances. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.
Figure 4.33: The effect of injection to production well distance on total exergy. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.34: Total power generation potential at different injection to production well distances. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.
4.3.5 1D Reservoir Flow

The fluid flow passing through a system is largely governed by the characteristics of the system. The main characteristics of a 1D reservoir are the reservoir temperature, reservoir depth (pressure), and reservoir permeability. In this section, the influence of these parameters on the geothermal fluid mass flow rate and power generation potential of H$_2$O and CO$_2$ EGS are investigated.

Reservoir Temperature

Figure 4.35 shows the effect of reservoir temperature on the mass flow rates of H$_2$O and CO$_2$ in the H$_2$O and CO$_2$ based EGS, respectively. The CO$_2$ mass flow rate was found to increase slightly as the reservoir temperature was raised from 200°C to 250°C mainly due to the negligible effect of temperature on its kinematic viscosity. The influence of reservoir temperature on the mass flow rate of H$_2$O was more pronounced, with 6% increase for every 25°C rise in reservoir temperature. The observed trend generally corresponds with the change in kinematic viscosity as a function of temperature.

The heat extraction rates of CO$_2$ and H$_2$O as a function of reservoir temperature is presented in Figure 4.36. It can be seen that the heat extraction rates for CO$_2$ and H$_2$O increase by about 12% and 20% for every 25°C rise in reservoir temperature. The increase in the heat extraction rate is mainly due to an increase in fluid specific enthalpies as the temperature increases. H$_2$O has a significantly higher change in enthalpy (108 kJ/kg from 200 to 225°C at 49.05 MPa) than that of CO$_2$ (39 kJ/kg). A higher mass flow rate with greater enthalpy change leads to a greater heat extraction rate for H$_2$O compared with CO$_2$.

The effect of reservoir temperature on EGS total exergy and power generation potential are shown in Figures 4.37 and 4.38, respectively. As shown in these figures, the total exergy and power generation potential increases as the reservoir temperature rises with CO$_2$, requiring a higher reservoir temperature than H$_2$O to achieve the same power generation potentials. For example, at injection pressure of about 9 MPa, CO$_2$ based EGS needs a reservoir temperature of 250°C to generate 6 MW power while the H$_2$O based EGS can potentially generate the same amount at a lower reservoir temperature of
200°C. This implies that at the given reservoir and well depth conditions, H₂O based EGS is a better choice for power generation.

Moreover, the CO₂ based EGS maximum power generation potential for the reservoir temperature range of between 200-250°C was obtained at the injection pressure just above 10 MPa. This value appeared to be independent of the reservoir temperature change.

*Figure 4.35: Geothermal fluid mass flow rates at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1km reservoir length.*
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Figure 4.36: Fluid heat extraction rates at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1km reservoir length.

Figure 4.37: Total exergy at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1km reservoir length.
Figure 4.38: Power potential at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1 km reservoir length.

Reservoir Depth

The reservoir depth directly influences the reservoir pressure. That is because the reservoir pressure is mainly defined by the hydrostatic pressure in the well. Figure 4.39 shows the mass flow rate of H₂O and CO₂ as a function of injection pressure at different reservoir depths. Clearly, CO₂ mass flow rate increases inversely with the reservoir depth/reservoir pressure while H₂O mass flow rate increases as the reservoir depth decreases from 5000 m to 3000 m. The increase in the CO₂ mass flow rate was four times greater than that of H₂O. The higher reservoir pressure gradients encountered by CO₂ at shallower depths (Figure 3.40) is mainly considered to be responsible for the observed higher CO₂ mass flow rates. The increase in the mass flow rate of CO₂ subsequently increases the CO₂ total heat extraction rate.

The total exergy and power generation potential at reservoir depth of 3000 m and 5000 m are shown in Figures 4.41 and 4.42, respectively. The CO₂ total exergy and optimum power generation potential decreases at shallower reservoir depths while H₂O total exergy and power generation potential are practically remain unchanged. The 6 MW
CO₂ optimum power generation potential at 5000 m depth decreased to 5 MW as the reservoir depth was reduced to 3000 m. The decrease in production pressure (Figure 4.43) and the strong dependence of CO₂ thermodynamic properties on both pressure and temperature are the reasons why the total exergy and power generation potential are changing as the reservoir depth changes. H₂O thermodynamic properties, however, are only slightly influenced by the pressure, and that is why altering the reservoir depth/pressure had a negligible effect on the total exergy and power generation potential of the H₂O based EGS.

Figure 4.39: Geothermal fluid mass flow rate at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.
Figure 4.40: Reservoir pressure gradient at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.41: Fluid total exergy at different reservoir depths.
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**Figure 4.42**: Total power potential at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

**Figure 4.43**: Production pressures at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.
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4.3.6 2D Reservoir Flow

A one-dimensional simulation of the fluid flow through the reservoir only considers the axial flow of geothermal fluids, hence providing limited information on the flow profiles within the reservoir. A two-dimensional simulation, on the other hand, allows us to capture the radial profile of the fluid and hence to investigate its effect on power generation potentials. A 2D radial flow model also makes a better representation of fluid flow in a homogenous porous media. In this section, the simulation results for 1D and 2D reservoir models are compared. Figure 4.44 shows the mass flow rate of CO₂ and H₂O as a function of the injection pressure using 1D and 2D reservoir models. Generally, the mass flow rates predicted by the 2D model for both fluids were found to be greater than the 1D model predictions, with 1D model underestimating the mass flow rates by more than 50%. This discrepancy was more pronounced at lower injection pressures as demonstrated in Figure 4.45 where the ratio of the mass flow rate prediction obtained from the 2D model and 1D model is presented versus the injection pressure. The total reservoir pressure loss obtained through 2D reservoir simulation, on the other hand, was smaller than that of the 1D simulation (Fig 4.46). The overall trends observed in Figures 4.44-4.47 can be associated with incorporating the radial fluid flow in the 2D model. As the fluid flows away from the bottom of the injection well (a line source), the area normal to the direction of the flow increases. The increasing area of the flow allows for greater mass flow rates as the distance away from the bottom of the injection well increases. As can be seen in Figure 4.47, much of the pressure in the 2D reservoir flow model was lost near the injection well whereas the 1D reservoir flow profile was linear along the reservoir. The higher mass flow rates predicted by the 2D reservoir model leads to higher total fluid exergy and power generation potential as demonstrated in Figures 4.48 and 4.49, respectively. Specifically, for CO₂ based EGS, the maximum CO₂ power generation potential predicted by the 2D model was 8.9 MW, almost 30% greater than the 1D prediction of 6.3 MW at the given conditions. Interestingly, based on the 2D simulations, the maximum power can be generated at a lower injection pressure of 8.5 MPa compared with the injection pressure of 10.5 MPa predicted earlier by the 1D reservoir modelling. The H₂O power generation potential
using the 2D reservoir model is estimated to be 80% more than the values obtained by the 1D simulation.

**Figure 4.44:** Geothermal fluid mass flow rate predicted by 1D and 2D reservoir models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5km well depth, and 1km reservoir length.
Figure 4.45: Ratio of fluid mass flow rate predicted by 2D to that of 1D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.46: Reservoir pressure loss comparison between 1D and 2D reservoir model predictions. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.
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**Figure 4.47**: CO\(_2\) 1D and 2D reservoir pressure profile from injection to production wells at 7.5 MPa injection pressure. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

![Diagram showing pressure profile](image)

**Figure 4.48**: Total exergy predictions using 1D and 2D reservoir flow models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

![Graph showing exergy predictions](image)
Chapter 4: One and Two-Dimensional Combined Reservoir and Power Plant Cycle Modelling for EGS

Figure 4.49: Total power generation potential of CO$_2$ and H$_2$O based EGS using 1D and 2D reservoir models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Well Configuration

The analysis presented in the previous sections were based on a well configuration of one injection well and one production well, the so called doublet well configuration. Other well configurations are (1) three well configuration with one injection well and two production wells whereby the ratio of injection to production wells is 1:2 and (2) five-spot well configuration with one injection well and four production wells whereby the ratio of injection to production wells is 1:4 were considered. The effect of the ratio of injection to production wells on the mass flow of geothermal fluids and power generation potentials of H$_2$O and CO$_2$ based EGS were investigated using the 2D radial reservoir flow model. The reference model was based on a 5000 m well depth, 49.05 MPa reservoir pressure, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.50 shows the effect of the ratio of injection to production wells on the mass flow rates of CO$_2$ and H$_2$O. It can be seen that the mass flow rate remains unchanged as the number of production wells increases. This is expected since the production wells are equally distanced from the injection well and therefore the same initial/boundary
remains imposed. As can be seen from Equation 4.1, the prediction of fluid mass flow rate is independent of conditions in the production wells. The total fluid mass flow rate is governed by the conditions in the injection well and in the reservoir.

The total exergy and power generation potential of CO\textsubscript{2} and H\textsubscript{2}O based EGS are presented in Figures 4.51 and 4.52, respectively. An increase in the ratio of the production to injection well only influenced the CO\textsubscript{2} total exergy and power generation potential, significantly increasing its energy output potential. Conversely, the increase in the number of production wells had a negligible effect on H\textsubscript{2}O total exergy and power generation potential. The observed behaviour can be explained considering that the frictional loss in the production well diminishes as the ratio of the production to injection well increases (see Figure 4.53). That is because for a given geothermal fluid mass flow rate, as the number of production well increases, the amount of fluid carried through each production well is reduced (i.e. the geothermal fluid mass flow rate through each production well is equal to the total mass flow rate at the injection well divided by the number of production wells). A lower mass flow rate in the production wells translates into a lower frictional loss (Fig 4.53). Subsequently, the lower frictional losses in the production well resulted in a higher production pressure (Fig 4.54). In adiabatic wellbore flow, a higher production pressure would also result in higher CO\textsubscript{2} production temperature (Fig 4.55) since CO\textsubscript{2} enthalpy strongly depends on both pressure and temperature. The high production pressure and temperature of CO\textsubscript{2} using a higher ratio of production to injection well explains the improvement in CO\textsubscript{2} total exergy and power generation potential, and therefore the power potential increases from 8.9 MW for doublet (1:1) to 12.1 MW for the five-spot well configuration (1:4 injection to production well ratio). In practice, however, increasing the number of production wells increases the initial investment costs so that a careful economic assessment is warranted to determine the balance between the cost of additional production wells and the gain in power output, which is not covered in this study.

Moreover, the numerical simulation using the 2D reservoir model and 1:4 injection to production well ratio was performed to assess the power generation potential at shallower reservoir depths. Figure 4.56 shows the mass flow rates of CO\textsubscript{2} and H\textsubscript{2}O as a
function of injection pressure at 3000 m and 5000 m depth. The H2O mass flow rate increased as the reservoir depth was reduced from 5000 m to 3000 m while CO2 mass flow rate had a greater rate of increase. This was found to be primarily due to the decrease in frictional loss in the injection well at a shallower depth (Fig 4.57). Figure 4.57 clearly shows that the total frictional loss of H2O decreased at a shallower depth while CO2 had greater total frictional loss at an injection pressure lower than 9 MPa and only had total frictional loss decreased at pressure higher than 10 MPa. Normalisation of the frictional loss, however, shows that both H2O and CO2 normalised frictional loss decreased at a shallower depth (Fig 5.48). The normalised frictional loss is computed by dividing the total frictional loss by the total mass flow rate. Clearly, as can be seen in the figure, H2O decreased normalised frictional loss almost uniformly at shallower depth while the CO2 had greater rate of decrease at higher injection pressure. This is expected since the well is shorter at a shallower depth; therefore, the frictional loss is lower. The CO2 greater rate of frictional loss decrease as the reservoir depth was reduced improved the reservoir pressure gradient as can be seen in Figure 4.59. The improved CO2 reservoir pressure gradient allowed for higher mass flow rates than H2O seen earlier in Figure 4.56.

The higher geothermal fluid mass flow rates at the shallower reservoir resulted to improved total exergy of CO2 and H2O based EGS as shown in Figure 4.60. H2O based EGS power generation potential increased as a direct consequence of increased H2O mass flow rate at the shallower reservoir. Conversely, the CO2 EGS maximum power generation potential decreased from 12.1 MW at 5000 m to 11.2 MW at 3000 m reservoir depth (Fig 4.61). The CO2 power generation potential is influenced by mass flow rate, production pressure, and production temperature at the wellhead. The CO2 wellhead production pressure was found to be lower at the shallower reservoir while production temperature was found to be higher at the shallower reservoir (see Figure 4.62, production temperature at the y-axis while production pressure at the secondary y-axis). To normalise the effect of both production pressure and temperature, the specific exergy of CO2 at different reservoir depths is presented in Figure 4.63. As can be seen in Figure 4.63, the specific exergy of CO2 at the shallower reservoir was found to be lower than the deeper reservoir and therefore explains the lower power generation
potential of CO$_2$ at the shallower reservoir. In practice, the shallower reservoir is desirable due to lower drilling and well costs; however, higher power potential at the deeper reservoir could cancel out the costs due to a higher power generation.

![Figure 4.50](image)

**Figure 4.50:** Effect of the injection to production well ratio on fluid mass flow rates. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.
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**Figure 4.51:** Effect of the injection to production well ratio on the fluid total exergy. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1 km injection to production distance.

![Graph](image)

**Figure 4.52:** Effect of the injection to production well ratio on EGS power generation potential. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1 km injection to production distance.

![Graph](image)
**Figure 4.53:** Effect of the injection to production well ratio on the frictional loss at the production well. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

**Figure 4.54:** Production pressure using different injection to production well ratios. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.
Figure 4.55: Production temperature using different injection to production well ratios. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1 km injection to production distance.

Figure 4.56: Geothermal fluid mass flow rate at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km injection to production distance.
Figure 4.57: Injection well frictional loss at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

Figure 4.58: Normalised frictional loss in the injection well at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.
Figure 4.59: Reservoir pressure gradient at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

Figure 4.60: Total fluid exergy at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.
**Figure 4.61:** EGS power potential at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.62:** CO₂ production temperature (red lines) and pressure (secondary y-axis, blue lines) at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.
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Figure 4.63: The predicted specific exergy at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model.

Reservoir Permeability

One of the characteristics that define a reservoir is permeability and is probably one of the most important factors in developing an EGS. Sufficient permeability is needed for the efficient utilisation of geothermal energy in the reservoir. The influence of reservoir permeability on the mass flow rates of CO\textsubscript{2} and H\textsubscript{2}O is presented in Figure 4.64. It can be seen in the figure that doubling the reservoir permeability increases CO\textsubscript{2} mass flow rate by as much as 30\% while H\textsubscript{2}O mass flow rate increases at a greater rate of as much as 80\%. The increase in mass flow rate is expected as Darcy’s law explicitly shows that at the same pressure gradient, higher permeability will result to a higher fluid mass flow rate in the reservoir.

Figure 4.65 shows the influence of reservoir permeability on power generation potentials of CO\textsubscript{2} and H\textsubscript{2}O based EGS. As shown in the figure, H\textsubscript{2}O power generation potential increased proportional to the increase in H\textsubscript{2}O mass flow rate as the reservoir permeability was doubled. Conversely, CO\textsubscript{2} power generation potential increased at a lower extent than H\textsubscript{2}O due to the fact that it has a lower heat capacity and susceptible to higher frictional losses in the well at high mass flow rates as discussed earlier. The plot
also shows that at a low reservoir permeability of $25 \times 10^{-15}$ m$^2$, the 7.8 MW maximum power generation potential of CO$_2$ at 9.5 MPa injection pressure was similar to the power generation of H$_2$O at an injection pressure lower than 8.5 MPa. These observations imply that CO$_2$ based EGS could generate the same power output as that of H$_2$O based EGS in a reservoir with low permeability.

![Figure 4.64](image)

**Figure 4.64:** Geothermal fluid mass flow rate at different reservoir permeabilities using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: $225^\circ$C reservoir temperature, $25^\circ$C injection temperature, 5 km reservoir depth, and 1km injection to production distance.
Figure 4.65: EGS power potential at different reservoir permeability using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

4.4 Concluding Remarks

Integrated 1D/2D reservoir-wellbore-power cycle models were developed to investigate the effect of operational, wellbore, and reservoir parameters on fluid mass flow rate, heat extraction rate, total exergy, and power generation potential of CO₂ and H₂O based EGS. Specifically, the parameters studied were injection temperature and pressure, well geometry and configuration, well to well distance, reservoir temperature, reservoir depth (reservoir pressure), and reservoir permeability. The CO₂ based EGS used the CO₂ thermosiphon power cycle model while the H₂O based EGS used a binary power cycle using isopentane as the secondary working fluid. The mass and energy balances were solved using Engineering Equation Solver (EES).

The integrated 1D/2D reservoir-wellbore-power plant model simulations showed that CO₂ based EGS has higher mass flow rates than H₂O based EGS. The power generation potential of H₂O based EGS, however, is greater than that of CO₂ based EGS in most cases. The observed findings were related to the thermodynamic properties of CO₂ and H₂O at the conditions studied. CO₂ thermodynamic properties are strongly influenced
by both temperature and pressure while $\text{H}_2\text{O}$ thermodynamic properties are only influenced by temperature (i.e. the effect of pressure is negligible). Specifically, $\text{CO}_2$ has significantly lower kinematic viscosities at reservoir conditions, allowing for higher mass flow rates while $\text{H}_2\text{O}$ has a higher heat capacity allowing for higher heat extraction rates with lower mass flow rates (i.e. larger enthalpy change). Moreover, $\text{CO}_2$ has a larger well frictional loss than $\text{H}_2\text{O}$ due to its lower average density in the well, reducing its total exergy and consequently lower power generation potential. At lower reservoir permeability, however, $\text{CO}_2$ and $\text{H}_2\text{O}$ based EGS have similar power generation potentials at injection pressures lower than 9.5 MPa. In most HDR projects, it is more likely to encounter low permeability reservoirs due to the absence of fluid; therefore, the development of $\text{CO}_2$ based EGS should be considered.

A comparison of 1D and 2D reservoir model simulation results showed that the 2D model predicted mass flow rates were higher than 1D. This is due to the radial flow of the fluid where the area normal to the direction of the flow increases as the fluid travels away from the injection well effectively, allowing for higher mass flow rates at the same reservoir pressure gradient.

The simulation results presented in this chapter only represent a steady state snapshot of the entire reservoir-wellbore-power production process, and “3D effect” was not considered. Transient changes in the reservoir and 3D effects will be addressed in the next chapter.
Chapter 5: Three-Dimensional Combined Reservoir and Power Cycle Modelling for EGS

This chapter presents a 3D reservoir model coupled with wellbore flow and power plant cycle modelling for CO$_2$ and H$_2$O based EGS to investigate 3D effects and time dependent changes in the reservoir due to thermal depletion. The transient effect of injection and reservoir parameters on mass flow rate, total exergy, and power generation potentials were investigated. TOUGH2, a numerical simulator for non-isothermal multi-phase and multi-component flows in permeable media, was used in the 3D reservoir modelling (Pruess, 2004; Pruess and Narasimham, 1985; Pruess et al., 1999). A modified version of ECO2N equation of state module for TOUGH2 was specifically used to predict CO$_2$ and H$_2$O fluid mass flow rates (Pruess and Spycher, 2007).

Section 5.1 describes the governing equations used in TOUGH2/ECO2N as reported in the TOUGH2 manual. This is followed by Section 5.2, which outlines the numerical methods used in this study and Section 5.3, which presents the validation and calibration of the 3D reservoir model.

The simulation results and discussion of the integrated 3D reservoir flow and power cycle modelling are presented in Section 5.4. The parameters investigated include injection temperature, reservoir temperature, reservoir pressure (depth), and rock permeability and porosity. The CO$_2$ based EGS reservoir performance at constant mass flow rate is also evaluated. A comparison of the predicted mass flow rates and heat extraction rates obtained from 1D, 2D, and 3D reservoir models as well as the effect of wellbore heat transmission on mass flow rates, heat extraction rates, and power generation potentials are presented in Section 5.4.
5.1 TOUGH2 Governing Equations

TOUGH2 solves mass and energy balances using the general form of the equation in which the term on the left hand side of the equation represents the total accumulation of mass or energy, the first term in the right hand side is mass or heat flux, and the second term represents generation of mass or energy

$$\frac{d}{dt} \int_{V_n} M^\kappa dV_n = \int_{\Gamma_n} \mathbf{n} \cdot \mathbf{F}^\kappa d\Gamma_n + \int_{V_n} \mathbf{q}^\kappa dV_n$$

(5.1)

where $V_n$ is an arbitrary sub-domain of the flow system bounded by closed surface $\Gamma_n$. $M$ is mass or energy per unit volume, $\kappa = 1,..., NK$ is the labelling for the different mass components ($H_2O$, $CO_2$, etc.) and $\kappa = NK+1$ is the thermal heat component, $F$ is the mass or heat flux, $q$ is the sinks or sources, and $\mathbf{n}$ is the normal vector on the surface element pointing inward into $V_n$.

In Equation 5.1, the accumulation of mass in a sub-domain is expressed as

$$M^\kappa = \phi \sum_\beta S_\beta \rho_\beta X_\beta^\kappa$$

(5.2)

where $\phi$ is the porosity, $\rho_\beta$ is the density of phase $\beta$, $S_\beta$ is the saturation of phase $\beta$ or the fraction of pore volume occupied by phase $\beta$, $X_\beta$ is the mass fraction of component $\kappa$ on phase $\beta$, and $\beta$ is the fluid phases (i.e. liquid, gas).

The thermal heat accumulation is similarly defined as

$$M^{NK+1} = (1-\phi) \rho_R C_R T + \phi \sum_\beta S_\beta \rho_\beta u_\beta$$

(5.4)

where $\rho_R$ is the rock grain density, $C_R$ is the specific heat of the rock, $u_\beta$ is the specific internal energy in phase $\beta$, and $T$ is the temperature.

Moreover individual phase fluxes is given by Darcy's law
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\[ F_\beta = \rho_\beta \upsilon_\beta = -k \frac{k_{\beta} \rho_\beta}{\mu_\beta} (\nabla P_\beta - \rho_\beta g) \]  

(5.4)

where \( \upsilon_\beta \) is the Darcy velocity or volume flux, \( k \) is the absolute permeability, \( k_{\beta} \) is the relative permeability to phase \( \beta \), \( \mu_\beta \) is the viscosity, and \( g \) is the gravitational acceleration.

\[ P_\beta = P + P_{c\beta} \]  

(5.5)

where \( P \) is the reference gas phase pressure and \( P_{c\beta} \) is the capillary pressure (\( \leq 0 \)).

The total advective mass flux is then

\[ F^s|_{adv} = \sum_\beta X^s_\beta F_\beta \]  

(5.6)

The heat flux that includes conductive and convective components is given as

\[ F^{NK+1} = -\lambda \nabla T + \sum_\beta h_\beta F_\beta \]  

(5.7)

where \( \lambda \) is the thermal conductivity and \( h_\beta \) is the specific enthalpy in phase \( \beta \).

The mass and energy equation (Equation 5.1) is discretised in space using the integral finite difference method (Edwards, 1972; Narasimhan and Witherspoon, 1976) while time is discretised as a fully implicit first-order finite difference.

In this software, the thermodynamic properties of H\(_2\)O are calculated from the equations given by the International Formulation Committee (1967). The properties of pure CO\(_2\) are calculated using the correlations developed by Altunin (1975). Properties of CO\(_2\)-brine mixtures are calculated from different correlations and the detailed description can be found in Pruess et al. (1999) and Pruess and Spycher (2007).
5.2 Integrated Modelling Approach

The integrated 3D reservoir-wellbore-power cycle model simulations were implemented in two steps. The first step is the 3D reservoir model simulations using TOUGH2/ECO2N that solved the mass and energy balance in the reservoir. The second step calculated the total exergy and power generation potential through wellbore and power plant cycle model simulations. The wellbore flow and power cycle modelling developed from the previous chapter (Sections 4.1.1 and 4.2) were used in the second part of the integrated model simulations. The flow in the injection and production wells was assumed adiabatic and the acceleration effects were assumed negligible. The CO₂ based EGS used CO₂ thermosiphon power cycle model and H₂O based EGS used binary power cycle using isopentane as secondary working fluid. The exergy calculation used for H₂O based EGS was based on exergy transferred by heat represented by Equation 3.11 in Chapter 3 while CO₂ based EGS used exergy calculation based on the enthalpy change represented by Equation 4.16 in Chapter 4.

The total pressure gradient between the production and injection well was assumed constant by assigning constant bottom-hole pressures at the injection and production wells. In this study the injection bottom-hole pressure was fixed at reservoir pressure plus 1 MPa and the bottom-hole production pressure was fixed at reservoir pressure minus 1 MPa. The 3D reservoir model simulations then calculated the transient mass flow rates and heat extraction rates.

A modified ECO2N fluid property module was used in the present study. ECO2N is a fluid property module for the TOUGH2 simulator (Version 2.0) that was designed for applications to geologic sequestration of CO₂ in saline aquifers (Pruess and Spycher, 2007). The temperature limitation of this module is 10 °C ≤ T ≤ 100 °C, the pressure limit is up to 60 MPa, and the salinities up are to halite saturation. In the modified ECO2N version, the temperature limitation was removed with a constraint so that only pure CO₂ or pure H₂O phases simulations were simulated; hence, no mixture of CO₂ and H₂O was considered.
The 3D reservoir model simulations were conducted using the pre and post-processing graphical interface PetraSim software for TOUGH2. A typical ¼ symmetrical areal model of a 1 km$^2$ five-spot well configuration was used in the simulation (Figure 5.1). As can be seen in the figure, a five-spot well configuration comprises of 1 injection well in the centre of a square and four production wells located at the four corners. Due to symmetry, only a quarter of the geometry of the 3D reservoir was used in the simulation to increase efficiency and speed of computational calculations. A modified CO2TAB file was used, covering wider pressure and temperature ranges appropriate for EGS application. CO2TAB lists the thermodynamic properties of CO$_2$ at different temperature-pressure conditions and is used by TOUGH2. CO2TAB is generated by FORTRAN77 program ‘co2tab3.f’ that implements Altunin’s CO$_2$ correlations.

The 3D reservoir and the blocks/cells that represent injection and production wellbores were first gravity equilibrated (i.e. considering the static head due to the weight of the fluid) to verify that the model can simulate realistic pressure and temperature profiles (Fig 5.2). For the case of CO$_2$, Figure 5.2 shows that the pressure increased as the reservoir layer depth increased while the temperature change was found to be negligible (not shown).
Figure 5.1: A five-spot well configuration: (a) top view of \( \frac{1}{4} \) section with an injection-production segment and (b) 3D reservoir model simulation.
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5.2.1 Simulation Inputs

The simulation inputs for the 3D reservoir modelling are summarised in Table 5.1 while the simulation inputs for the power cycle modelling are summarised in Table 5.2. The injection and production temperatures and pressures used in the 3D reservoir flow modelling as well as the predicted mass flow rates and heat extraction rates from the 3D reservoir flow modelling were used as simulation inputs for the wellbore flow modelling. Production and injection wells were assigned a single diameter of 0.2315 m and surface pipe roughness of 40 μm, which are similar to the one used in 1D/2D integrated modelling from Chapter 4, allowing for direct comparison of the 3D simulations with those of 1D/2D findings.

Table 5.1: Reservoir and injection/production parameters used in the 3D reservoir model simulations

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td></td>
</tr>
<tr>
<td>Thickness, m</td>
<td>305 (6 layers)</td>
</tr>
<tr>
<td>Fracture spacing, m</td>
<td>50</td>
</tr>
<tr>
<td>Permeable volume fraction</td>
<td>2%</td>
</tr>
<tr>
<td>Permeability in fracture domain, $10^{-15}$ m$^2$</td>
<td>0.5, 5 and 50</td>
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</tbody>
</table>
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<table>
<thead>
<tr>
<th>Nos. of MINC</th>
<th>5, 3, 2, porous</th>
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<tr>
<td>Porosity in fracture domain</td>
<td>50%</td>
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<tr>
<td>Permeability in rock matrix, ( \times 10^{-15} \text{ m}^2 )</td>
<td>0.5, 5 and 50</td>
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<tr>
<td>Porosity in rock matrix</td>
<td>0.2%, 2%</td>
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<tr>
<td>Rock grain density, kg/m(^3)</td>
<td>2650</td>
</tr>
<tr>
<td>Rock specific heat, kJ/kg</td>
<td>1000</td>
</tr>
<tr>
<td>Rock thermal conductivity, W/m-(^\circ)C</td>
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</table>

**Initial conditions**

<table>
<thead>
<tr>
<th>Reservoir fluid</th>
<th>CO(_2), H(_2)O</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir temperature, °C</td>
<td>175, 200, 225</td>
</tr>
<tr>
<td>Reservoir pressure, MPa</td>
<td>20, 35, 50</td>
</tr>
</tbody>
</table>

**3D Reservoir Model**

<table>
<thead>
<tr>
<th>Production area, km(^2)</th>
<th>1 km(^2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fraction of the area modelled</td>
<td>(1/4)</td>
</tr>
<tr>
<td>Spatial resolution, m</td>
<td>20.83, 45.45</td>
</tr>
<tr>
<td>Injection temperature, °C</td>
<td>20, 35, 70</td>
</tr>
<tr>
<td>Injection pressure, MPa</td>
<td>+1 of reservoir pressure</td>
</tr>
<tr>
<td>Production pressure, MPa</td>
<td>-1 of reservoir pressure</td>
</tr>
</tbody>
</table>

**Table 5.2: Input parameters used in the power cycle**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Binary Plant for H(_2)O based EGS</th>
<th>CO(_2) Thermosiphon Power Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine Efficiency</td>
<td>85%</td>
<td>85%</td>
</tr>
<tr>
<td>Pump Efficiency</td>
<td>70%</td>
<td>70%</td>
</tr>
<tr>
<td>Geofluid mass flow rate</td>
<td>Predicted from 3D reservoir and wellbore flow modelling</td>
<td></td>
</tr>
<tr>
<td>Geofluid Inlet Temperature*</td>
<td>Predicted from 3D reservoir and wellbore flow modelling</td>
<td></td>
</tr>
<tr>
<td>Geofluid Outlet Temperature*</td>
<td>Predicted from 3D reservoir and wellbore flow modelling</td>
<td></td>
</tr>
<tr>
<td>Pinch Temperature</td>
<td>5°C</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Pump Circulation Pressure</td>
<td>2.793 MPa</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Condenser Pressure</td>
<td>101.325 kPa</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>

*In case of H\(_2\)O based EGS, the predicted injection wellhead temperature from the wellbore-reservoir modelling is considered the minimum possible value H\(_2\)O exiting the binary power cycle plant.*
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5.3 Three-Dimensional Reservoir Model Validation

The 3D reservoir model developed in this study using the modified ECO2N equation of state (EOS) module was validated against the theoretical predictions of Pruess (2008). Specifically, 3D reservoir predictions in terms of mass flow rates and heat extraction rates were compared with those of Pruess’ (2008) model predictions. Pruess (2008) used a Lawrence Berkeley National Laboratory in-house "EOSM" equation of state module for TOUGH2. EOSM equation of state module is not commercially nor publicly available to use, and no details on its limitation nor other capabilities are reported in the open literature. The rock matrix permeability value used as an input in Pruess’ (2008) model, however, was not explicitly stated. Hence, for the validation purposes, Pruess’ model was first reproduced using different rock matrix permeability values at 20 MPa and 200°C reservoir condition and 20°C injection bottom-hole temperature model simulations.

A match on CO₂ predicted mass flow rates and heat extraction rates was found for the well design where all layers of the production well that intersected the reservoir were open to production using a 12×12 areal grid (41.67 m side length), rock matrix permeability of 1.9x10⁻¹⁴ m², and porosity of 0.2% (see Figure 5.4). For the well design, where only the topmost 50 m layer of the reservoir intersected by the well was open to production, however, the 12×12 areal grid of the ¼ symmetric model gave higher mass flow rates and heat extraction rates as shown in Figure 5.4.

Very good matches were found for the predicted mass flow rates and heat extraction rates of the two production well designs described above when the areal grid size was doubled to 24×24 (20.83 m side length), rock matrix permeability was assigned values equal to that of the fracture domain permeability (5x10⁻¹⁴ m²), and the rock matrix porosity was set 0.2%. Figure 5.6 shows the matched predicted mass flow rates and heat extraction rates of well design where all intersected layers of the reservoir were open to production while Figure 5.6 shows the matched plots for the well design where only the topmost 50 m intersected layer of the reservoir was open to production. It can be seen in
Figure 5.5 that CO₂ predicted mass flow rate was very high and increased from about 400 kg/s to 430 kg/s in 20 years before declining slowly whilst CO₂ heat extraction rate was relatively stable at about 140 MW in the first ten years then declined rapidly to 47 MW after 35 years. Conversely, Figure 5.6 shows that the CO₂ predicted mass flow rate and heat extraction rate were relatively stable at about 178 kg/s and 63 MW, respectively, for well design where only the topmost 50 m intersected layer of the reservoir was open to production. Moreover, it was clear that when all layers of the reservoir were open to production, thermal breakthrough of the injected cold CO₂ was a lot faster than when only the top 50 m layer of the reservoir was open to production as can be seen in Figures 5.7 and 5.8, respectively. As seen in Figure 5.7, where all layers of the reservoir were open to production, reservoir temperature near the production well dropped significantly after 25 years compared to when only the topmost 50 m layer of the reservoir was open to production as shown in Figure 5.8.

The results from this section of the study proved the applicability of modified ECO2N for use in the 3D reservoir simulations. It also successfully calibrated the 3D reservoir model to be used in the succeeding simulations (i.e. defined the rock matrix permeability and grid block size to be used).
Figure 5.3: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where all layers of the reservoir were open to production using 12 x 12 areal grids, rock matrix permeability of $1.9 \times 10^{14}$ m$^2$, and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
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Figure 5.4: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where only the topmost 50 m layer of the reservoir was open to production using 12×12 areal grids, rock matrix permeability of 1.9x10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
Figure 5.5: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where all layers of the reservoir were open to production using 24×24 areal grids, rock matrix permeability of \( 5 \times 10^{-14} \text{ m}^2 \), and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
Figure 5.6: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where only the topmost 50 m layer of the reservoir was open to production using 24x24 areal grids, rock matrix permeability of 5x10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
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Figure 5.7: 3D temperature contour from injection to production well after 25 years when all layers of the reservoir were open to production. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.8: 3D temperature contour from injection to production well after 25 years when only the topmost 50m of the reservoir was open to production. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
5.4 Wellbore Heat Transport

In general, the integrated 1D, 2D, and 3D reservoir-wellbore-power plant cycle model developed from Chapter 4 and in this chapter used the adiabatic wellbore flow model. That is the heat exchange between the wellbore and the earth formation is neglected. To investigate the influence of wellbore heat loss on mass flow rates, heat extraction rates and power generation potentials of CO\textsubscript{2} and H\textsubscript{2}O based EGS and wellbore heat transport are considered in the integrated 2D and 3D reservoir-wellbore-power plant cycle model simulations presented in Section 5.4.7.

The heat transfer modelling between the wellbore and earth formation was based on the pioneering work of Ramey (1962) and as expanded by Hasan and Kabir (2012) and Izgec (2008). The equation for fluid temperature in vertical wells developed by Agarwal and Anderson (2010) was adapted and used in this study.

The fluid temperature in the production wellbore was calculated as

\[
T_F = T_{eibh} - g_G \left[ (L - Z) - \frac{(1 - e^{(Z-L)l_R})}{L_R} \right] \tag{5.8}
\]

Similarly, the injection wellbore fluid temperature was expressed as

\[
T_F = T_{eivh} + g_G \left[ (Z) - \frac{(1 - e^{(-Z)l_R})}{L_R} \right] \tag{5.9}
\]

where \( L_R = \frac{2\pi}{C_p m} \left[ \frac{r_1 U_l k_e}{k_e + (r_i U_l T_D)} \right] \) is the relaxation parameter \( \tag{5.10} \)

\[
T_D = \ln \left[ e^{-0.2t_D} + \left( 1.5 - 0.3719 e^{-0.2t_D} \right) \sqrt[2]{t_D} \right] \) is the dimensionless temperature \( \tag{5.11} \)

\[
t_D = \frac{\alpha \cdot t}{r_3^2} \) is the dimensionless time \( \tag{5.12} \)

where \( t \) is time, \( \alpha \) is thermal diffusivity of the earth, \( r_3 \) is the wellbore radius, \( r_l \) is the inner radius of the well casing, \( k_e \) is the thermal conductivity of the earth, \( U_l \) is the
overall heat transfer coefficient, \( C_p \) is the specific heat of the fluid, \( m \) is the mass flow rate, \( g_G \) is the geothermal gradient, \( Z \) is the depth, \( L \) is the length of the well, \( T_{ewh} \) is the wellhead temperature of the fluid, and \( T_{ebh} \) is the bottom-hole temperature of the fluid.

The overall heat transfer coefficient was predicted based on radial heat transfer between the wellbore fluid and the earth (Figure 5.9). As Figure 5.9 shows, the heat exchange between the wellbore and the earth formations consists of convection heat transfer from the fluid to the well casing, heat conduction from the well casing to well cement, and heat conduction from the well cement to the earth formations. The overall heat transfer coefficient was calculated as

\[
\frac{1}{U_t} = \frac{1}{h_t} + r_1 \frac{\ln\left(\frac{r_2}{r_1}\right)}{k_{ca}} + r_2 \frac{\ln\left(\frac{r_3}{r_2}\right)}{k_{ce}}
\]

Figure 5.9: Schematic diagram of the wellbore cross section.

The fluid heat transfer coefficient was calculated based on the modified Gnielinski correlations (Dang and Hihara, 2004)
\[ h_i = \frac{Nu \times k_f}{d} \quad (5.14) \]

\[ Nu = \frac{(f/8)(Re - 1000)Pr}{1.07 + 12.7(f/8)(Pr^{2/3} - 1)}, \text{ Nusselt number} \quad (5.15) \]

\[ Pr = \frac{C_p \mu}{k_f}, \text{ Prandtl number} \quad (5.16) \]

where \( f \) is the friction factor, \( \mu \) is the viscosity of the fluid, \( k_f \) is the thermal conductivity of the fluid, \( Re \) is the Reynolds number, and \( d \) is the inner diameter of the casing.
5.5 Results and Discussion

The integrated 3D reservoir-wellbore-power plant cycle modelling discussed in this chapter focuses on the power generation potentials of CO\textsubscript{2} and H\textsubscript{2}O based EGS as opposed to the total heat extraction rates presented by Pruess (2008). As discovered in this study, higher heat extraction rates do not necessarily translate to higher power generation outputs. Production wellhead temperature and pressure in particular strongly influence CO\textsubscript{2} based EGS power generation potentials. Likewise, H\textsubscript{2}O mass flow rates largely influence the H\textsubscript{2}O based EGS power generation potentials.

In this chapter, particular attention is given to the transient effect of injection and reservoir parameters on mass flow rate, total exergy, and power generation potentials. Specifically, the effect of the type of reservoir-production connection (production well design), injection temperature, reservoir temperature, reservoir pressure, and reservoir permeability and porosity are investigated.

5.5.1 Reservoir-Production Well Connection

The effect of the type of reservoir connection to the production well on CO\textsubscript{2} and H\textsubscript{2}O mass flow rates, heat extraction rates, total exergy, and power generation potentials were investigated using the 3D reservoir model developed in this work. Generally, two types of connections were examined namely, (i) fully open reservoir where all layers of the reservoir were open to production well and (ii) partially open reservoir where only the topmost layer of the reservoir was open to the production well (in this study, the topmost layer had a thickness of 50 m). Three-dimensional reservoir model simulations were performed at a reservoir pressure of 20 MPa, reservoir temperature of 200\textdegree C, and injection bottom-hole temperature of 20\textdegree C, comparing the power generation potentials of CO\textsubscript{2} and H\textsubscript{2}O based EGS. Moreover, the simulations were performed for a plant typical lifespan of 35 years.

A comparison of CO\textsubscript{2} and H\textsubscript{2}O mass flow rates and heat extraction rates for a fully open reservoir where all layers of the reservoir were open to production well is presented in Figure 5.10. It was found that CO\textsubscript{2} mass flow rates were about more than 4 times higher
than H$_2$O mainly due to its low kinematic viscosity at the tested conditions. Such a high CO$_2$ mass flow rate (i.e. about $410$ kg/s) resulted in an initially very high heat extraction rate. This was followed by a sharp decline (144 MW to 47 MW within 35 years). The sharp decline is associated with thermal depletion due to the initial high heat extraction rates. The H$_2$O heat extraction rate, in contrast, reduced at a much slower rate (i.e. from 24 MW to 16 MW in 35 years). Generally, the observed behaviour is the same as that of the fluid mass rates indicating, that the heat extraction rate is directly influenced by the mass flow rates of the geothermal fluids. It was observed that the CO$_2$ mass flow rate increased slightly on the onset of a sharp decline of the heat extraction rate mainly due to a slight decrease in its kinematic viscosity as the reservoir temperature decreased. A similar trend was observed for a partially open well design where only the topmost layer of the reservoir was open to production as shown in Figure 5.11. The mass flow rates and heat extraction rates were lower but stayed steady for a longer period of time than that of production design producing from all layers of the reservoir.

The total exergy of CO$_2$ and H$_2$O based EGS at different production well designs is presented in Figure 5.12. It shows that when producing from all layers of the reservoir, CO$_2$ based EGS total exergy of about 27 MW was maintained for 7 years declining rapidly to zero after 29 years. The H$_2$O based EGS total exergy decline was found to be much slower at an average decline rate of about 0.3 MW per year. However, when only the topmost layer of the reservoir was open to the production well, CO$_2$ based EGS total exergy remained unchanged at about 14 MW for a much longer period of 25 years. This was followed by a slow decline reaching 10 MW after 35 years. Using a partially open reservoir was found to be even more effective for the H$_2$O based EGS, where the total exergy declined slowly from 19 MW to 13 MW in 35 years. Examining the production temperature and pressure profiles of the CO$_2$ over the plant lifespan (Figures 5.13 and 5.14) shows a strong correlation between these parameters and the total exergy trends observed above. As shown in Figures 5.13 and 5.14, for the well design producing from all layers of the reservoir, CO$_2$ wellhead production temperature and pressure remained steady for at least 1/5$^{th}$ of the plant lifespan. This steady period, however, became longer, reaching more than 2/3$^{rd}$ of the plant lifespan of 35 years when the partially open
reservoir was used. H\textsubscript{2}O wellhead production temperature and pressure, however, remained almost unchanged over time for both production well designs.

Figure 5.13 shows that CO\textsubscript{2} wellhead production temperature was stable at about 180\textdegree C for only 7 years in the well design producing from all layers of the reservoir while it was stable for 21 years when producing only from the topmost 50 m layer of the reservoir. Conversely, H\textsubscript{2}O wellhead production temperature was stable at a temperature similar to that of 200\textdegree C reservoir temperature for both production well designs.

It can be seen in Figure 5.14 that CO\textsubscript{2} wellhead production pressures were significantly higher than H\textsubscript{2}O. The CO\textsubscript{2} wellhead production pressures when producing from all layers of the reservoir at about 13 MPa was only stable for 13 years then declined to 7.4 MPa after 35 years while the CO\textsubscript{2} wellhead production pressures when producing only from the topmost 50 m layer of the reservoir was higher and stable at 14 MPa for 30 years. In comparison, H\textsubscript{2}O wellhead production pressures on both production well designs were similar and stable at about 1.9 MPa.

The observed CO\textsubscript{2} wellhead pressure and temperature behaviour was considered to be a combined artefact of low CO\textsubscript{2} density in the production wellbore and high fluid mass flow rates. The low density of CO\textsubscript{2} (250 kg/m\textsuperscript{3} at the bottom and 180 kg/m\textsuperscript{3} at the surface) meant that a lower fluid pressure head (lower hydrostatic pressure) needs to be overcome and therefore, when compared with water, less static pressure loss was encountered, leading to higher pressure at the wellhead. Also, the high mass flow rate associated with the partially open reservoir design relative to that of fully open reservoir leads to a higher frictional loss creating greater pressure drops, hence reducing the production wellhead pressure.

Furthermore, the initially very high CO\textsubscript{2} heat extraction rates at the fully open reservoir design led to a rapid thermal depletion of the reservoir, meaning that after sometime, the CO\textsubscript{2} temperature entering the production well was significantly lower than that of the initial reservoir temperature.

The predicted CO\textsubscript{2} and H\textsubscript{2}O injection wellhead temperature are presented in Figures 5.15 and 5.16. Generally, the CO\textsubscript{2} injection wellhead temperature was found to be at
least 2/3rd of that of H₂O while the pressure was seven times greater than H₂O injection pressure. The partially open reservoir well design of CO₂ based EGS was found to need lower temperature and pressure of about 11°C and 4.6 MPa, respectively, than the fully open reservoir well design with temperature and pressure requirements of 16°C and 9.5 MPa, respectively.

Figure 5.17 presents the comparison of power generation potential of CO₂ and H₂O based EGS. It shows that a CO₂ based EGS with production well design producing only from the topmost 50 m of the reservoir generated the highest stable power output at about 11 MW for 25 years (7/10th of the plant life span) while the highest power generation from H₂O based EGS was obtained when producing from all layers of the reservoir with initial power output of about 12 MW that steadily declined to 7 MW after 35 years. The plot also shows that CO₂ based EGS producing from all layers of the reservoir had stable power output of about 9.5 MW for 7 years then declined rapidly to zero power output after 25 years while H₂O based EGS producing only from the topmost 50 m layer had an initial power output of about 8.1 MW that declined to 5.6 MW after 35 years. Clearly, the CO₂ based EGS producing from the topmost layer of the reservoir outperforms the H₂O based EGS and CO₂ based EGS producing from all layers of the reservoir by generating more power at a near constant rate. In addition, since the open section of the production wells need to be shorter and/or shallower than the injection well, the drilling and well costs could be lower than the fully open well design. The low CO₂ wellhead injection temperature of about 11°C, however, limits the location to the colder regions of the world such as Iceland and Greenland.
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Figure 5.10: CO₂ and H₂O based EGS mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.11: CO₂ and H₂O based EGS mass flow rates and heat extraction rates producing from only the topmost 50 m of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
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Figure 5.12: CO₂ and H₂O based EGS total exergy at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.13: Predicted CO₂ and H₂O production wellhead temperature at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
Figure 5.14: Predicted CO$_2$ and H$_2$O production wellhead pressure at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.15: Predicted CO$_2$ and H$_2$O injection wellhead temperature at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
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Figure 5.16: Predicted CO\textsubscript{2} and H\textsubscript{2}O injection wellhead pressure at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200\textdegree C reservoir temperature, and 20\textdegree C injection bottom-hole temperature.

Figure 5.17: CO\textsubscript{2} and H\textsubscript{2}O based power generation potential at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200\textdegree C reservoir temperature, and 20\textdegree C injection bottom-hole temperature.
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5.5.2 Injection Bottom-hole Temperature

The effect of injection bottom-hole temperature on CO\textsubscript{2} mass flow rates and heat extraction rates in fully open reservoir and partially open reservoir designs are shown in Figures 5.18 and 5.19, respectively. For this study, two injection bottom-hole temperatures of 20°C and 35°C were selected to represent Australian regions with moderate to arid climates. It can be seen that as the CO\textsubscript{2} injection bottom-hole temperature increased, the CO\textsubscript{2} mass flow rates increased while the CO\textsubscript{2} heat extraction rates decreased. The increase in CO\textsubscript{2} mass flow rate is associated with the 10% decrease in CO\textsubscript{2} kinematic viscosity as the temperature increases from 20°C to 35°C. The decrease in heat extraction rates, on the other hand, was due to a decrease in CO\textsubscript{2} specific enthalpy change (i.e. lower CO\textsubscript{2} heat capacity) between the injection and production wells.

CO\textsubscript{2} based EGS total exergy and power generation potential at different injection bottom-hole temperatures are presented in Figures 5.20 and 5.21, respectively. Generally, as the CO\textsubscript{2} injection bottom-hole pressure increased, the CO\textsubscript{2} total exergy and power generation potential decreased. In general, the CO\textsubscript{2} based EGS with a partially open reservoir design outperformed the EGS with the fully open reservoir, producing a near uniform power output over the lifespan of the plant. The CO\textsubscript{2} based EGS with a fully open reservoir design only had a comparable power output for a period of 7 years (i.e. 1/5th of the plant lifespan). Clearly, the practical application of CO\textsubscript{2} based EGS will be strongly influenced by the injection temperature, which in turn depends largely on the ambient temperature. In Australia, the average ambient temperature varies widely depending on the location and season influencing the performance of CO\textsubscript{2} based EGS.
Figure 5.18: Effect of injection bottom-hole temperature on CO₂ mass flow rates and heat extraction rates in production well design producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

Figure 5.19: Effect of injection bottom-hole temperature on CO₂ mass flow rates and heat extraction rates in production well design producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.
Figure 5.20: Effect of CO\textsubscript{2} injection bottom-hole temperature on CO\textsubscript{2} based EGS total exergy at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

Figure 5.21: CO\textsubscript{2} Effect of CO\textsubscript{2} injection bottom-hole temperature on CO\textsubscript{2} based EGS power generation potential at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.
The effect of H$_2$O injection bottom-hole temperature of 70°C on H$_2$O mass flow rates and heat extraction rates in fully open reservoir and partially open reservoir designs were also investigated (Figures 5.22 and 5.23, respectively). The H$_2$O injection bottom-hole temperature of 70°C was chosen as it corresponds to the outlet temperature of H$_2$O stream exiting the heat exchanger, which was used to pre-heat the isopentane working fluid in the binary power plant. This stream can be directly injected back into the injection well. As can be seen in Figures 5.22 and 5.23, H$_2$O mass flow rates increased by 60-80% as the H$_2$O injection bottom-hole temperature increased from 20°C to 70°C for both production well designs simply because the kinematic viscosity is almost halved in value (i.e., approximately 0.42 m$^2$/s at 70°C and 1 m$^2$/s at 20°C). Similarly, the H$_2$O heat extraction rate increased as the temperature was raised to 70°C using a fully open reservoir well design. In the case of a partially open reservoir design, however, the average heat extraction rate remained unchanged as the temperature was increased due to a decrease in specific enthalpy change.

The H$_2$O based EGS total exergy and power generation potential are presented in Figures 5.24 and 5.25, respectively. The figures show that the H$_2$O based EGS total exergy and power generation potential increase as the H$_2$O injection bottom-hole temperature increases. The H$_2$O based EGS with the fully open reservoir well design operated at an injection bottom-hole temperature of 70°C, was found to have outperformed the other cases by generating in average at least 1.5 times more power. In terms of stability of the power output over the lifespan of the plant, the H$_2$O based EGS with the topmost layer being open to the production well at an injection bottom-hole temperature of 70°C was considered to be a better option as the rate of change was 0.05 MW/y with an average power output of 8.9 MW.

A comparison of CO$_2$ and H$_2$O based EGS power generation potentials (Figure 5.26) indicates that considering the binary power cycle used in most geothermal power plant installations are already technologically mature and commercially available, the H$_2$O injection in locations with higher ambient temperatures can generate more power than their equivalent CO$_2$ based EGS, it is more practical to develop H$_2$O based EGS with binary power cycle in arid regions of world.
Figure 5.22: Effect of injection bottom-hole temperature on \( \text{H}_2\text{O} \) based EGS mass flow rates and heat extraction rates in production well design producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

Figure 5.23: Effect of injection bottom-hole temperature on \( \text{H}_2\text{O} \) based EGS mass flow rates and heat extraction rates in production well design producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.
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Figure 5.24: Effect of H$_2$O injection bottom-hole temperature on H$_2$O based EGS total exergy at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

Figure 5.25: Effect of H$_2$O injection bottom-hole temperature on H$_2$O based EGS power generation potential at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.
Figure 5.26: Comparison of CO$_2$ and H$_2$O based EGS power generation potential at different injection bottom-hole temperatures. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

5.5.3 Reservoir Temperature

Reservoir temperature is arguably one of the most important indicators of geothermal potential being used during exploration and pre-development phase of a geothermal field. In this study, medium grade temperatures were used to investigate the effect of geothermal reservoir temperature on CO$_2$ and H$_2$O based EGS mass flow rates and power generation potentials. As the reservoir temperature increased from 175°C to 225°C, the heat extraction rate for the fully open reservoir well design rapidly increased, reaching a plateau at 225°C (Figure 5.27). The mass flow rate in this system was less influenced by the temperature rise altering between 400 and 420 kg/s as the temperature changed between 175°C and 225°C. In the CO$_2$ based EGS with the well design producing from the topmost layer, however, the mass flow rate was reduced at an average rate of 12 kg/s per 25°C while the heat extraction rate increased at an average rate of about 2.5 MW per 25°C as the temperature increased (Figure 5.28). The observed behaviours are driven by the changes in CO$_2$ kinematic viscosity and the CO$_2$ enthalpy changes as a function of pressure and temperature, as discussed earlier. Figures 5.29 and 30 show the effect of reservoir temperature on CO$_2$ based total exergy and
power generation potentials, respectively. In the case of the CO\textsubscript{2} based EGS with well design producing from the topmost layer of the reservoir, the total exergy and power output increased as the reservoir temperature increased. Specifically, the stable power generation potential increased at a rate of 1 MW per 25°C. Overall, the CO\textsubscript{2} based EGS with well design producing from all layers of the reservoir underperform both in terms of power output and its stability over the lifespan of the plant. The main parameters influencing the CO\textsubscript{2} based EGS total exergy and power generation potentials were considered to be the CO\textsubscript{2} mass flow rate and the thermal depletion of the reservoir as discussed in Section 5.3.1.

\textbf{Figure 5.27:} Effect of reservoir temperature on CO\textsubscript{2} mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.
Figure 5.28: Effect of reservoir temperature on CO₂ mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.29: CO₂ based EGS total exergy at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.
Figure 5.30: CO₂ based EGS power generation potential at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

In a fully open reservoir-production design, the H₂O mass flow rate increased by 2 to 6% as the reservoir temperature increased by 25°C while heat extraction rate increased by 16% to 20% (Figure 5.31). Similar trends were observed in H₂O based EGS with partially open reservoir-production well design as can be seen in Figure 5.32. The increase in mass flow rate was due to the decrease in H₂O kinematic viscosity as temperature increases while the increase in heat extraction rate was due to the combined effect of the increase in H₂O enthalpy change and the increase in mass flow rate. Consequently, the total exergy and power generation potential of H₂O based EGS increased as the reservoir temperature increased as shown in Figures 5.33 and 34, respectively. In the fully open reservoir, the average power generation output increased by 2 MW per 25°C temperature rise while in a partially open reservoir, the average increase was 1.7 MW. Comparison of CO₂ and H₂O based EGS power generation potentials in Figure 5.35 show that a CO₂ based EGS with a partially open reservoir-production well design performs better in providing a steady power output in longer periods than any H₂O based EGS at different reservoir temperatures. It should be reiterated, however, that at a 20°C injection bottom-hole temperature used in the
Simulations on this part of the study, the CO\(_2\) injection wellhead injection temperature was ~11°C while H\(_2\)O was ~25°C and therefore limited the CO\(_2\) based EGS application in colder regions of the world.

**Figure 5.31:** Effect of reservoir temperature on H\(_2\)O mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

**Figure 5.32:** Effect of reservoir temperature on H\(_2\)O mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.
Figure 5.33: \( \text{H}_2\text{O} \) based EGS total exergy at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.34: \( \text{H}_2\text{O} \) based EGS power generation potentials at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.
Figure 5.35: Comparison of CO$_2$ and H$_2$O based EGS power generation potential at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

5.5.4 Reservoir Pressure (Depth)

Typically, the pressure of a reservoir at any depth is assumed to be equal to the hydrostatic pressure at that depth (i.e. the pressure at 2 km depth is approximately 20 MPa). A similar assumption is made on this part of the study. The effect of reservoir pressure (depth) on CO$_2$ mass flow rates and heat extraction rates for a CO$_2$ based EGS producing from all layers of the reservoir is presented in Figure 5.36. The figure shows that the CO$_2$ mass flow rates and initial heat extraction rates decrease as the reservoir pressure increases. Specifically, the CO$_2$ average mass flow rates decreased from 411 kg/s to 398 kg/s and 362 kg/s while average heat extraction rates decreased from 117 to 110 and 97 MW as the reservoir pressure increased from 20 MPa to 35 MPa and 50 MPa, respectively. Conversely, Figure 5.37 shows that when producing only from the topmost layer of the reservoir, the average CO$_2$ mass flow rate was lowest at 20 MPa reservoir pressure while the average CO$_2$ heat extraction rate was lowest at 50 MPa.

These behaviours exemplified the influence of pressure on CO$_2$ thermodynamic and transport properties. Figure 4.11 in Chapter 4 shows that the CO$_2$ kinematic viscosity is lower at a lower pressure (i.e. 20 MPa) and temperatures lower than 100°C but is higher
at a lower pressure and temperatures higher than 140°C. This peculiar dependency of CO₂ kinematic viscosity on pressure and temperature explained the observed CO₂ mass flow rate trends. Moreover, the temperature-enthalpy diagram of CO₂ presented in Figure 5.38 shows that CO₂ enthalpy change is higher at lower pressure and this explained the observed CO₂ heat extraction rate trends.

Generally, in the fully open reservoir-production design, the decline rate of the total exergy decreased as reservoir pressure increased, but the initial total exergy was similar at pressures between 20 and 35 MPa and lowest at 50 MPa (Figure 5.39). In a partially open reservoir-production design, the total exergy at 35 and 50 MPa were similar while total exergy at 20 MPa was the lowest. Similar trends were observed on the CO₂ power generation potentials as presented in Figure 5.40. Specifically, it shows that in the partially open reservoir, 12 MW of stable power output could be generated for 25 years at 35 MPa reservoir pressure. The CO₂ based EGS power generation potential was found to be influenced by CO₂ production and injection wellhead pressures. The effect of reservoir pressure on the predicted production wellhead pressures and injection wellhead pressures are presented in Figures 5.41 and 5.42, respectively. It can be seen in Figure 5.41 that as the reservoir pressure increased, the CO₂ production wellhead pressures also increased. Figure 5.41 also shows that the CO₂ production wellhead pressures in partially open reservoir were higher than that of the fully open reservoir. Figure 5.42 shows that the injection wellhead pressure increased as the reservoir pressure increased. It also shows that the injection wellhead pressures in the fully open reservoir were higher than in the partially open reservoir. The increase in CO₂ injection wellhead pressure at a higher reservoir pressure was due to the high frictional loss in the deeper injection well. The CO₂ total pressure drop from the production to the injection wellheads is presented in Figure 5.43. Generally, the figure shows that the total pressure drop increased as the reservoir pressure increased. It also shows that the total pressure drop was higher in the partially open reservoir.

Reservoir pressure did not significantly influence mass flow rates and heat extraction rates of H₂O based EGS in fully open or partially open reservoirs (Figures 5.44 and 5.45, respectively). This was due to the independence of H₂O kinematic viscosity and
H$_2$O specific enthalpy on pressure and temperature ranges considered in the study. A look at the H$_2$O temperature-enthalpy diagram presented in Figure 5.46 shows that pressure only influence H$_2$O specific enthalpy above the critical point. The critical point of water is at 374°C and 22.064 MPa.

As mentioned earlier, reservoir pressure is dictated by reservoir depth and vice versa. This implies that reservoir pressure also influence the costs of drilling well/s and could impact the economic viability of an EGS project. In the H$_2$O based EGS, a higher reservoir pressure will lower the net present value of the project due to higher drilling costs. In CO$_2$ based EGS, however, an increase in reservoir pressure increases the power output by up to 1 MW (i.e. from 20 MPa to 35 MPa) and could possibly negate the additional costs of drilling.

![Figure 5.36: Effect of reservoir pressure on CO$_2$ mass flow and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.](image-url)
Figure 5.37: Effect of reservoir pressure on CO$_2$ mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.38: CO$_2$ temperature-enthalpy diagram showing isobaric lines.
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Figure 5.39: CO\textsubscript{2} based EGS total exergy at different reservoir pressure (depth) and different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.40: CO\textsubscript{2} based EGS power generation potential at different reservoir pressure (depth) and at different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.
Figure 5.41: The predicted CO$_2$ production wellhead pressures at different reservoir pressures (depths) and different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.42: The predicted CO$_2$ injection wellhead pressures at different reservoir pressures (depths) and at different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.
**Figure 5.43:** CO$_2$ total pressure drop from injection to production wellhead at different reservoir pressures and at different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

**Figure 5.44:** Effect of reservoir pressure on H$_2$O mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.
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Figure 5.45: Effect of reservoir pressure on H\textsubscript{2}O mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.46: H\textsubscript{2}O temperature-enthalpy diagram showing isobaric lines.

5.5.5 Rock Permeability and Porosity

The natural permeability values of reservoirs vary by several orders of magnitudes. For example, the equivalent permeabilities calculated from the Soultz granite inferred from
geophysical and flow log analysis range from $5.2 \times 10^{-17}$ m$^2$ to $9.6 \times 10^{-16}$ m$^2$ (Sausse et al., 2006), and intact granite has $1.6$ to $3.8 \times 10^{19}$ m$^2$ permeabilities (Selvadurai et al., 2005). Permeability can be enhanced through a number of stimulation methods such as hydro fracturing, acid, and chemical stimulations. Porosities of granite, on the other hand, range from 0.2 to 4% (http://www.granite-sandstone.com/granite-physical-properties.html).

The decrease of rock matrix permeability by one and two orders of magnitudes significantly decreased CO$_2$ mass flow rates and heat extractions in both fully open and partially open reservoirs as can be seen in Figures 5.47 and 5.48, respectively. Figure 5.47 shows that the average CO$_2$ mass flow rates in the fully open reservoir dropped from about 400 kg/s to 185 kg/s and 29 kg/s for one and two order of magnitude decreased in permeability, respectively while heat extraction rates similarly dropped. The same trends can be observed in the partially open reservoir: CO$_2$ mass flow rates decreased from about 178 kg/s to 117 and 27 kg/s as the permeability decreased by one and two order of magnitudes, respectively while the average CO$_2$ heat extraction rates dropped from 64 MW to 42 and 10 MW, respectively.

Figures 5.49 and 5.50 show the effect of permeability on H$_2$O mass flow rates and heat extraction rates in fully open and partially open reservoirs, respectively. In the fully open reservoir (Figure 5.49), as the permeability decreased by one and two order of magnitudes, mass flow rates decreased from about 90 kg/s (after 2 years) to ~23 kg/s and ~2.6 kg/s, respectively while heat extraction rates dropped from ~67 MW to ~18 and ~2 MW, respectively. Similarly, in the partially open reservoir (Figure 5.50), as permeability decreased by one and two order of magnitudes, the H$_2$O mass flow rates dropped from ~61 kg/s (after 2 years) to ~20 kg/s and ~2.6 kg/s, respectively while H$_2$O heat extraction dropped from ~46 MW to ~15 and ~2 MW, respectively. These observations were expected since Darcy’s law describes implicitly that permeability directly influences fluid mass flow rates given the same pressure gradient.

CO$_2$ and H$_2$O based EGS power generation potentials at different reservoir permeability and reservoir-production well designs are presented in Figures 5.51 and 5.52, respectively. Generally, CO$_2$ and H$_2$O based EGS power output decreased as the
permeability decreased due to the decrease in mass flow rates. At the lowest permeability tested (5 x10^{-16} m^2), the CO2 based EGS power generation potential was stable and higher at about 2 MW than H2O based EGS power output at about 0.3 MW in both fully open and partially open reservoirs. However, in the fully open reservoir, the CO2 based EGS power output using permeability one order of magnitude lower than the reference was higher and stable at about 11.6 MW for 15 years. As can be seen in Figure 5.51, this power output was comparable to the CO2 based EGS producing from a partially open reservoir and using the reference reservoir permeability. This was found to be due to similar CO2 mass flow rates (i.e. 185 kg/s versus 178 kg/s). A comparison of CO2 and H2O based EGS power generation outputs simulated using 5 x10^{-15} m^2 reservoir permeability (one order of magnitude lower than the reference) is presented in Figure 5.53. It shows that CO2 based EGS was capable of generating 8 MW (or more) stable power output for the entire lifespan of the power plant while H2O based EGS was only capable of generating 2.7 MW average power output. Clearly, CO2 based EGS performs better than H2O based EGS at a lower reservoir permeability.

Changing the rock matrix porosity from 0.2% to 2% did not significantly influence CO2 based EGS mass flow rates and heat extraction rates (Figure 5.54). This was also true for H2O based EGS mass flow rates and heat extraction rates (not shown). Porosity is the void space that is capable of holding fluid. Porosity, in theory, can influence the heat content of the rock matrix since the fluid it contains can have a different heat capacity than the solid rock masses and therefore can influence the heat exchange between geofluid and the rock matrix. However, in granitic rocks, porosity does not vary widely; hence, its influence on mass flow rates and heat extraction rates was negligible.
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Figure 5.47: Effect of rock matrix permeabilities on $CO_2$ mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.48: Effect of rock matrix permeabilities on $CO_2$ mass flow rates and heat extraction rates producing from only the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.
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Figure 5.49: Effect of rock matrix permeabilities on $H_2O$ mass flow rates and heat extraction rates by producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.50: Effect of rock matrix permeabilities on $H_2O$ mass flow rates and heat extraction rates by producing from only the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.
Figure 5.51: Effect of rock matrix permeability on CO$_2$ based EGS power generation potentials. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.52: Effect of rock matrix permeability on H$_2$O based EGS power generation potentials. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.
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**Figure 5.53:** Comparison of CO₂ and H₂O based EGS power generation potentials at $5 \times 10^{-15} \text{m}^2$ permeability and at different reservoir-production well designs. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

**Figure 5.54:** Effect of rock matrix porosity on CO₂ mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.
5.5.6 CO₂ based EGS Constant Mass Flow Rate Injection

The performance of a CO₂ based EGS power generation process at constant mass flow rates of 252 kg/s and 444 kg/s were investigated. The chosen lower mass flow rate was obtained from 2D reservoir model simulations where the power output was the maximum. The higher mass flow rate was obtained when the injection well diameter was twice that of the production well. The integrated model simulations were conducted using 20 MPa and 200°C reservoir condition, 25°C injection wellhead temperature and in a fully open reservoir.

The CO₂ heat extraction rates at different constant injection mass flow rates are presented in Figure 5.55. The figure shows that the CO₂ heat extraction rates at 252 kg/s injection was relatively stable for 20 years, dropping only by 4 MW from 87 to 83 MW before declining to 58 MW after 35 years while the heat extraction rates at 444 kg/s was only stable for 10 years (150 to 145 MW) before declining rapidly to 47 MW after 35 years. Conversely, the 252 kg/s injection power generation potential was stable for 20 years at about 9.5 MW before declining to 5.4 MW after 35 years while 444 kg/s injection power output was stable only for 10 years at 17.8 MW before dropping rapidly to 2.2 MW (Figure 5.56). An analysis of the CO₂ based EGS power generation potential showed that the 295 MW-year total power generated using 252 kg/s injection was smaller than that of the 413 MW-year accumulated using 444kg/s injection. Similarly, the 2758 MW-year total heat extracted using 252 kg/s injection was smaller than that of the 3840 MW-year total heat extracted using 444 kg/s injection. Overall, the calculated total thermal efficiencies were the same for both injection mass flow rates at 10.7%. The simulation results implied that one can find optimum CO₂ injection mass flow rate to obtain a stable power output for a given period of time.
Figure 5.55: CO₂ mass flow in the production well and heat extraction rates at different CO₂ constant mass flow rate injections. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 25°C injection wellhead temperature.
Figure 5.56: Total exergy and power generation potential at different constant CO\textsubscript{2} mass flow rate injections. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 25°C injection wellhead temperature.

5.5.7 Spatial Reservoir Dimension

The number of spatial reservoir dimensions used in modelling increases complexities and simulation times. Typically, 3D is required for detailed, accurate, and realistic model simulations but requires complex programming and most often leads to acquisition of highly specialised third-party software like TOUGH2, FLUENT for CFD, and others. However, for a rapid and approximate assessment of a model, 1D or 2D model analysis may suffice during the initial evaluation.

This section compared the simulation results of CO\textsubscript{2} and H\textsubscript{2}O based EGS with 1D, 2D, and 3D reservoir model coupled with 1D wellbore flow model. Common to all model simulations were adiabatic wellbore flow, 25°C wellhead injection temperature, 200°C reservoir temperature, 49 MPa production well bottom-hole pressure, 5000 m well depth, and 700 m areal distance between the injection and production wells. The 3D
reservoir model simulation used 35°C injection bottom-hole temperature, which approximately equated to 25°C wellhead injection temperature.

The simulation results from Section 5.4.1 and prior studies (Pruess, 2008) have shown that producing from all layers of the 3D reservoir model causes rapid thermal depletion compared with producing only from the topmost layer. It is operationally and economically wise to have stable production power outputs; therefore, in this part of the study, the 3D reservoir model simulation results were based on production from partially open reservoir (topmost layer).

Figures 5.57 and 5.58 show the predicted CO₂ mass flow rates and heat extractions rates using a different number of spatial reservoir dimensions, respectively. They show that the predicted CO₂ mass flow rates and heat extraction rates from the 2D and 3D reservoir flow models were in good agreement while the 1D reservoir model gave lower values. These observations implied that the CO₂ mass flow rate at the specified condition was not significantly influenced by "3D" effects or the effect of gravity on the fluid flow in the reservoir. This was due to a low CO₂ density. The low CO₂ density meant low hydrostatic pressure, and the fluid pressure difference between the top and bottom layers of the reservoir was not enough to influence fluid flow in the reservoir.

The predicted H₂O mass flow rates and heat extraction rates using a different number of spatial reservoir dimensions are presented in Figures 5.59 and 5.60, respectively. The figures show that H₂O mass flow rates and heat extraction rates increased as the number of spatial reservoir dimensions increased. These meant that the "3D" effect was significant for H₂O. This was due to high H₂O density (high hydrostatic pressure). The pressure fluid difference between the top and bottom layers of the reservoir increased the reservoir pressure gradient acting on the fluid and enhanced the flow toward the production well.
Figure 5.57: Predicted CO₂ mass flow rates using a different number of spatial reservoir dimensions.

Figure 5.58: Predicted CO₂ heat extraction rates using a different number of spatial reservoir dimensions.
Figure 5.59: Predicted $\text{H}_2\text{O}$ mass flow rates using a different number of spatial reservoir dimensions.

Figure 5.60: Predicted $\text{H}_2\text{O}$ heat extraction rates using a different number of spatial reservoir dimensions.
5.5.8 Wellbore Heat Transport

A coupled 2D reservoir-wellbore flow CO₂ based EGS model simulation was conducted at 200°C and 49.05 MPa reservoir conditions (5 km well depth), 700 m well to well distance, and five spot well configurations to determine the effect of wellbore heat transport on CO₂ mass rates and heat extraction rates. The wellhead injection pressure was kept constant at 9.5 MPa and the model was run for up to 30 years of simulation time.

The effect of wellbore heat transport on CO₂ mass flow rates and heat extraction is presented in Figure 5.61. It shows that CO₂ mass flow rates increased from 202 to 228 kg/s (12.9 % improvements) while the heat extraction rates increased from 57 to about 69 MW (21% improvements). The increase in CO₂ mass flow rate was found to be due to a lower CO₂ temperature along the length of the injection wellbore at times larger than 1 year while the increase in CO₂ heat extraction rates were due to higher production temperatures and pressures in addition to the increase in mass flow rates. Figure 5.62 presents the CO₂ temperature profiles in the injection well at different times when wellbore heat transport is considered and at adiabatic flow. It shows that CO₂ temperature decreased as time increased while at adiabatic condition the CO₂ bottom-hole temperature was higher than at the wellhead. The lower CO₂ temperature increased the CO₂ density along the injection well, which in turn lowered the frictional loss in the well, thus allowing for higher mass flow rates. Figure 5.63 shows that CO₂ density in the injection well increased as time increased. CO₂ production wellhead temperature and pressure profiles at different times are presented in Figures 5.64 and 5.65, respectively. Figure 5.64 shows that CO₂ production temperature over long periods was higher than that of the adiabatic condition while Figure 5.65 shows that CO₂ production pressure at large times were slightly higher than that of the adiabatic condition.
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Figure 5.61: CO$_2$ based EGS mass flow rates (secondary y-axis) and heat extraction rates when wellbore heat transport is considered (solid lines) and at adiabatic condition (broken lines).

Figure 5.62: CO$_2$ temperature profile at the injection well at different times and at adiabatic condition.
Figure 5.63: $CO_2$ density profile of the injection well at different times and at adiabatic condition.

Figure 5.64: $CO_2$ temperature profile of the production well at different times and at adiabatic condition.
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Figure 5.65: CO₂ pressure profile of the production at different times and at adiabatic condition.

The predicted CO₂ mass flow rates from the 3D reservoir model simulations at 50 MPa and 200°C reservoir condition were used in the wellbore-power plant cycle model simulations to determine the effect of wellbore heat transport on power generation potentials. During the 3D reservoir model simulations, the injection bottom-hole temperature and pressure were kept constant at 35°C and 51 MPa, respectively.

Wellbore heat transport decreases CO₂ based EGS heat extraction rates but increases the power generation potentials as can be seen in Figure 5.66. The figure shows that CO₂ based EGS power generation potential increased by 0.25-0.76 MW (2.7-9.6%). The decrease in CO₂ heat extraction rates was expected due to the heat loss in the production wellbore and increase in injection temperatures and pressures along the injection wellbore. The increase in CO₂ power generation output was found to be due to increased production temperatures and pressures. The injection and production wellhead temperatures and pressures are presented in Figures 5.67 and 5.68, respectively for both adiabatic and non-adiabatic (i.e. heat transport) in wellbore. Figure 5.67 shows that the injection wellhead temperatures and pressures increased when wellbore heat transport
was considered. Similarly, Figure 5.68 shows that production wellhead temperatures and pressures were higher when the wellbore heat transport was considered.

Figure 5.66: CO\textsubscript{2} based EGS heat extraction rates and power potential (secondary y-axis) when wellbore heat transport is considered (solid lines) and at adiabatic wellbore condition (broken lines).

Figure 5.67: CO\textsubscript{2} injection temperature and pressure (secondary y-axis) needed to maintain constant injection bottom-hole condition. The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.
Figure 5.68: CO₂ production temperature and pressure (secondary y-axis). The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

The effect of wellbore heat transport on H₂O heat extraction rates and power generation potentials is presented in Figure 5.69. It shows that H₂O based EGS heat extraction rates were lower on average by about 2.1 MW compared with adiabatic flow while H₂O based EGS power generation potentials were slightly lower by 2.7% (0.24 MW to 0.34 MW). These observed differences were due to the lower H₂O injection and production wellhead temperatures and pressures. Figures 5.70 and 5.71 present the H₂O injection and production wellhead temperatures and pressures at different times under both adiabatic and non-adiabatic (i.e. heat transfer) conditions. It can be seen in Figure 5.70 that the wellbore heat transport in the injection well decreased H₂O wellhead injection temperatures and pressures. Figure 5.71 shows that the H₂O wellhead production temperatures and pressures also decreased when wellbore heat transport is considered. The approximately 20°C difference in H₂O wellhead temperatures between the adiabatic condition and when production wellbore heat transport was considered at large times was significantly higher than the 15°C or less difference in CO₂ wellhead temperatures. This was due to the fact that H₂O specific heat capacity in the production wellbore was more than 2 times greater than CO₂ specific heat capacity (see Figure 5.72). Figure 5.72 shows the CO₂ and H₂O specific heat capacity profile in the
production well. It shows that the fluid specific heat capacity was slightly lower at large times (10 years) in the upper part of the production well when wellbore heat transport was considered than at adiabatic condition. The fluid specific heat capacity directly influenced the fluid heat transfer coefficients, which in turn influenced the overall heat transfer coefficient between the fluid and the reservoir formation.

**Figure 5.69:** $H_2O$-EGS heat extraction rates (left axis) and power potential (right axis) when wellbore heat transport is considered (solid lines) and at adiabatic wellbore condition (broken lines).

**Figure 5.70:** $H_2O$ injection temperature and pressure (secondary y-axis) needed to maintain constant injection bottom-hole condition. The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

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Figure 5.71: H₂O production temperature and pressure (secondary y-axis). The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

Figure 5.72: CO₂ and H₂O specific heat capacity profile in the production well when wellbore heat loss was considered after 10 years and at adiabatic condition.
5.6 Concluding Remarks

Integrated 3D reservoir-wellbore-power cycle models were developed to investigate the effect of injection and reservoir parameters on fluid mass flow rate, heat extraction rate, total exergy, and power generation potential of CO$_2$ and H$_2$O based EGS. In particular, injection temperature, reservoir temperature, reservoir pressure, and reservoir permeability and porosity were studied. The influence of constant mass flow rate injection and wellbore heat transport on heat extraction rates and power generation potentials of CO$_2$ and H$_2$O based EGS were also investigated. The 3D reservoir flow modelling used TOUGH2/ECO2N, a numerical simulator for non-isothermal multi-phase and multi-component flows in permeable media, to predict fluid mass flow rates and heat extraction rates of CO$_2$ and H$_2$O based EGS. Wellbore flow and power cycle modelling used the Engineering Equation Solver software program to determine total exergy and power generation potentials of CO$_2$ and H$_2$O based EGS. The CO$_2$ based EGS used the CO$_2$ thermosiphon power cycle model while the H$_2$O based EGS used a binary power cycle using isopentane as the secondary working fluid.

The integrated model simulations showed that generally, CO$_2$ based EGS has higher mass flow rates and heat extraction rates than H$_2$O based EGS. Stable power generation outputs from CO$_2$ based EGS could be achieved when producing only from the topmost layer of the reservoir. Specifically, approximately 11 MW and 8 MW of stable power output for 25 years could be generated from 20 MPa and 200°C reservoir at about 11°C and 25°C CO$_2$ injection wellhead temperatures, respectively. In contrast, H$_2$O based EGS producing from all layers of the reservoir at 20 MPa and 200°C could generate on average about 9.5 MW and 15 MW at about 25°C and 70°C injection wellhead temperatures, respectively, for the same period. Increase in reservoir temperature increases both CO$_2$ and H$_2$O based EGS power generation potential due to an increase in fluid specific enthalpy change. An increase in reservoir pressure did not affect H$_2$O based EGS while CO$_2$ based EGS performs slightly better at higher reservoir pressures. CO$_2$ based EGS mass flow rates and power generation potentials at low reservoir permeability were several times higher than H$_2$O based EGS. The effect of wellbore heat transport on H$_2$O based EGS power generation potential was greater than on CO$_2$
based EGS. The observed findings were due to the influence of pressure and temperature of thermodynamic and transport properties of CO$_2$ and H$_2$O. CO$_2$ thermodynamic properties were strongly influenced by temperature and pressure while H$_2$O thermodynamic properties were only strongly influenced by temperature. CO$_2$ kinematic viscosity was lower than H$_2$O kinematic viscosity at the temperature and pressure ranges considered.

Generally, CO$_2$ based EGS could generate stable higher power outputs at low permeability and deeper reservoir and at low injection temperature than H$_2$O based EGS. Conversely, H$_2$O based EGS performs better at high permeability reservoirs and at high injection temperatures.
Chapter 6: Fluid-Rock Interaction under Conditions Pertinent to HDR/EGS Reservoir Conditions

The theoretical and experimental studies of fluid-rock interaction under conditions pertinent to a typical EGS reservoir are presented in this chapter. The first section describes the experimental set-up and the fluid-rock interaction apparatus used for batch and flow-through experiments. The apparatus is capable of operating up to 50 MPa and up to 400°C simulated reservoir conditions using CO₂ and H₂O. Batch CO₂-rock interaction experiments were conducted at different simulated reservoir pressures and temperatures while flow-through experiments were performed using CO₂ and H₂O at different flow rates.

In these experiments, Australian granite samples collected from the surface and drilled wells were used to represent the HDR reservoir formation. The granite characteristics and preparation method are presented in Section 6.2. The surface granites were collected from the Moonbi granite outcrop in the New England Highway, NSW. The granite drill cores were from the wells Nambucurra 1 and Mossgeil 1 at Murray-Darling Basin, NSW.

The results and discussion on batch and flow-through fluid-rock interaction experiments are presented in Section 6.3. The CO₂-rock interaction batch experiments using Moonbi pulverised granites are presented in the Section 6.3.1 and 6.32 while the results of flow-through experiments using H₂O and CO₂ at different flow rates are presented in Section 6.3.3 and 6.3.4. The XRD and SEM analysis of the pulverised granites used in the experiments are presented in Section 6.3.5. The transport properties of CO₂ and H₂O in the simulated reservoir are presented in Section 6.3.6.
6.1 Experimental

A fluid-rock interaction apparatus was designed and fabricated to examine fluid-rock interactions under conditions pertinent to CO\textsubscript{2} and H\textsubscript{2}O based EGS. This customised apparatus enabled flow-through experimental studies of unconsolidated rock samples with CO\textsubscript{2} and saturated brines at pressures up to 50 MPa and temperature up to 400\degree C. Figures 6.1 and 6.2 show the actual and schematic diagram of the fluid rock interaction apparatus, respectively. The apparatus is consisted of (i) single non-rocking furnace with heater to maintain the temperature, (ii) pressure vessel to house the flexible titanium cell, (iii) titanium cell assembly to contain the unconsolidated rock sample and fluid, (iv) digital back pressure regulator to maintain the system pressure inside the reaction cell, (v) pneumatic confining pressure controller to maintain the pressure inside the pressure vessel, (vi) piston accumulator with re-circulating chiller (PolyScience Compact Chillers LS5) to store liquid CO\textsubscript{2} at constant temperature, (vii) high pressure pump (LabAlliance Model CP HPLC Column Packing Pump) to operate and maintain the pressure in the piston accumulator, and (viii) a data monitoring and acquisition system. The piston accumulator used water as the hydraulic fluid to pressurise the CO\textsubscript{2}. The fluid and rock were contained in a double-ended all titanium flexible reaction cell (160 ml) or double ended all titanium rigid reaction cell (18 ml) with 10 micron filter at both ends. The apparatus was fabricated by Coretest Systems, Inc. based in Morgan Hill, California, USA. The apparatus can be identified by system model number HFS-340Z.

Batch CO\textsubscript{2}-rock interaction experiments were conducted to determine possible interactions of CO\textsubscript{2} with the rock in the absence of H\textsubscript{2}O. Batch CO\textsubscript{2}-rock interaction experiments were conducted at different simulated reservoir pressures of 20 MPa and 35 MPa and temperatures of 200\degree C and 250\degree C. The batch CO\textsubscript{2}-rock interaction experiments were run up to 15 days. Before starting any experiment, the o-ring seals in the back pressure regulator valve head assembly and in the piston accumulator are checked and replaced when necessary. These are necessary to properly regulate the system pressure and prevent or at least minimise leakage of pneumatic fluid (H\textsubscript{2}O) in the piston accumulator. The next step was to fill the piston accumulator with liquid CO\textsubscript{2}.
and maintain at 20°C temperature and at the target simulated reservoir pressure. Then the titanium reaction cell assembly was loaded with pre-weight pulverised granite and installed inside the furnace. The apparatus is then purged and pressurised to the target reservoir pressure using CO₂. After checking for leaks and maintaining the desired pressure, the furnace is turned on to raise the temperature to the desired value. The system pressure was kept constant by a high pressure pump. The temperature was kept constant automatically by the built-in thermostat in the furnace. Fluid samples were taken after 1, 7, and 15 days.

CO₂ and H₂O flow-through fluid-rock interaction experiments were conducted at 20 MPa and 250°C simulated pressure and temperature, respectively. The flow-through fluid-rock interaction experiments were run for 15 days at volumetric flow rates of 0.05 ml/min, 0.20 ml/min and 0.50 ml/min and using pulverised granites collected from different Australian sources. Granites were collected from the surface at the Moonbi outcrop near New England Highway, NSW and from Nambucurra 1 and Mossigei 1 drilled boreholes at the Murray-Darling Basin, NSW. The procedure followed in the flow-through experiments was similar to that of the batch experiments except that after attaining the desired temperature of the system, the high pressure pump was continuously operated together with the digital back pressure regulator to maintain the desired system pressure. The minimum operating flow rates for the apparatus was found to be 0.2 ml CO₂/min and 0.05 ml H₂O/min, below which the reactor pressure dropped, and hence the flow could not be maintained. The piston accumulator was refilled with liquid CO₂ at least every 3 days when using the 0.2 ml CO₂/min flow rate or at least every day for the 0.5 ml CO₂/min flow rate.

During CO₂ batch and flow-through fluid-rock interaction experiments, the so called “reacted” CO₂ was allowed to bubble in 2% nitric acid solution to capture and collect the species that may have been dissolved in supercritical CO₂. The system pressure and temperature was kept constant at simulated reservoir conditions by pumping fresh CO₂ during the CO₂ bubbling process. A weight of 2% nitric acid solution was measured before and after each sample collection to detect any abnormal changes due to contamination or solid particle carries over. For the flow-through H₂O-rock interaction
experiments, however, the fluid sample collected were weighted and preserved by adding nitric acid to make a 4% solution. The higher nitric acid concentration for the H\textsubscript{2}O-rock interaction experiments was due to the expected higher silica concentration, and the 4% nitric acid concentration is the common preservation method for hydrothermal samples.

The fluid samples collected were analysed using Varian 710/715-ES ICP-OES for elemental analyses. The pulverised granites used in the experiments were analysed using x-ray fluorescence (Spectro X’Lab 2000 Polarised ED-XRF) for major oxide composition and trace elements, x-ray diffraction (Philips Diffractometer PW1710) for qualitative mineral analysis, and scanning electron microscopy (Philips XL30 SEM + Oxford ISIS EDS + Gatan Mini Cathodoluminescence Detector) for image analysis of the mineral surfaces. Approximately 25 g of Moonbi pulverised granite sample packed in the double ended rigid titanium reactor were used in the fluid-rock interaction experiments. Figure 6.3 shows the double ended rigid titanium reaction cell.

The concentration of elements in CO\textsubscript{2} \((C_{CO2}, \text{mg/kg CO}_2 \text{ or ppm})\) was calculated using the Equation 6.1

\[
C_{CO2} = \frac{C_AV_A}{(V_T-V_R)\rho_{CO2}}
\]

where \(C_A\) is the concentration of the element in the nitric acid solution in mg/L, \(V_A\) is the volume of the nitric acid solution, \(V_T\) is the volume of the reactor, \(V_R\) is the volume of the rock specimen (assumed equal to 2.7 g/cc), and \(\rho_{CO2}\) is the density of CO\textsubscript{2}.

The CO\textsubscript{2} contained in the piston accumulator was kept condensed at 20\textdegree C during the fluid-rock interaction experiments so as to maintain the constant mass flow rate of CO\textsubscript{2} being pumped from the piston accumulator. O-rings in the piston accumulator were regularly replaced to minimise leakage of H\textsubscript{2}O into the CO\textsubscript{2} side of the chamber. The pulverised granites samples were dried and kept at a 120\textdegree C oven before use.
Figure 6.1: The actual fluid-rock interaction apparatus. The high pressure pump in the picture was different from the one used during experiments.
Figure 6.2: Schematic diagram of the fluid-rock interaction apparatus.

Figure 6.3: Double ended rigid titanium reaction cell.
6.2 Granite Sample Characteristics and Preparation

The HDR geothermal reservoir conditions were simulated using granite samples collected from Australian geological sources. Three samples were gathered: One sample was from the granite outcrop at Moonbi near the New England Highway in NSW, Australia, and the other two were drill core samples from intersected granite from Mossgiel 1 and Nambucurra 1 boreholes at Murray-Darling Basin, NSW, Australia. The samples from Moonbi were randomly collected at the surface. Mossgiel samples were randomly collected from fragmented drill cores at depths of 1793-1796 meters while Nambucurra 1 samples were from the drill core sample at depths of 260.9-261.4 meters and were cut longitudinally. Mossgiel and Nambucurra 1 drill core samples were acquired from W B Clarke Geoscience Centre at Londonderry Core Library. Figure 6.4 shows the ground of the Moonbi granite outcrop near New England Highway, NSW. Figures 6.5 and 6.6 show the sections of the granite drill cores where the sample for Mossgiel and Nambucurra were collected, respectively.

The granite samples were cleaned, crushed, and pulverised using a tungsten carbide ring mill (N.V. Tema Ring Mill) for 3 minutes. Figure 6.7 shows crushed and pulverised samples from Nambuccura borehole. The pulverised samples were then analysed for particle size distribution using MALVERN Instruments Mastersizer E. The analysis of particle size distributions for Nambucurra, Mossgiel, Moonbi pulverised samples are presented in Figures 6.8, 6.9, and 6.10, respectively. It can be seen that the average particle size of the pulverised samples collected at Nambucurra, Moonbi and Mossgiel were 51.8 μm, 16.1 μm, and 5.7 μm, respectively. Clearly, the average particle size for each sample was different even though they were subjected to the same milling time and procedure. The observed differences are possibly due to different mineral compositions and mineral alterations as shown in Tables 6.1 and 6.2.
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Figure 6.4: Moonbi granite outcrop, New England Highway, NSW, Australia.

Figure 6.5: Mossgiel drilling core section at 1793-1796 meter depth.
**Figure 6.6:** Nambucurra 1 drilling core section at 260.9-261.4 m.

**Figure 6.7:** Crushed samples (top) and the pulverised samples (bottom) inside the tungsten carbide ring mill.
Figure 6.8: Nambucurra 1 pulverised sample particle size distributions. The average particle size is 51.8 μm.
Figure 6.9: Moonbi pulverised sample particle size distributions. The average particle size is 16.1 μm.
Figure 6.10: Mossgiel pulverised sample particle size distributions. The average particle size is 5.7 μm.

The major oxide composition of the pulverised granites samples were analysed using fused bead X-ray fluorescence (XRF) from two different laboratories. Fused bead XRF analytical results from AMDEL Limited is presented in Table 6.1 while the fused bead XRF analytical results from Electron Microscope and X-Ray Unit (EMX), Central Scientific Services, The University of Newcastle is presented in Table 6.2. The fused
bead XRF analytical results from the two laboratories were identical. The identical XRF analytical results from the two laboratories showed good pulverised granite sample homogeneity. The samples consisted mainly of SiO$_2$ and Al$_2$O$_3$ with Moonbi sample having twice as much CaO than Mossgiel and Nambucurra samples.

**Table 6.1:** Major oxide compositions of the granite samples from AMDEL Limited fused bead XRF analytical results

<table>
<thead>
<tr>
<th>Major Oxides</th>
<th>Detection Limit</th>
<th>Moonbi Wt %</th>
<th>Mossgiel Wt %</th>
<th>Nambucurra Wt %</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO$_2$</td>
<td>0.02</td>
<td>67</td>
<td>66.5</td>
<td>72.7</td>
</tr>
<tr>
<td>Al$_2$O$_3$</td>
<td>0.02</td>
<td>14.8</td>
<td>14.4</td>
<td>13.9</td>
</tr>
<tr>
<td>CaO</td>
<td>0.02</td>
<td>3.14</td>
<td>1.52</td>
<td>1.32</td>
</tr>
<tr>
<td>Fe$_2$O$_3$</td>
<td>0.02</td>
<td>3.91</td>
<td>5.4</td>
<td>2.49</td>
</tr>
<tr>
<td>K$_2$O</td>
<td>0.02</td>
<td>4.34</td>
<td>3.99</td>
<td>4.45</td>
</tr>
<tr>
<td>MgO</td>
<td>0.02</td>
<td>1.93</td>
<td>1.98</td>
<td>0.72</td>
</tr>
<tr>
<td>Na$_2$O</td>
<td>0.02</td>
<td>3.03</td>
<td>2.87</td>
<td>2.92</td>
</tr>
<tr>
<td>P$_2$O$_5$</td>
<td>0.02</td>
<td>0.24</td>
<td>0.20</td>
<td>0.18</td>
</tr>
<tr>
<td>SO$_3$</td>
<td>0.02</td>
<td>*nd</td>
<td>*nd</td>
<td>*nd</td>
</tr>
<tr>
<td>TiO$_2$</td>
<td>0.02</td>
<td>0.57</td>
<td>0.75</td>
<td>0.32</td>
</tr>
<tr>
<td>MnO</td>
<td>0.02</td>
<td>0.09</td>
<td>0.09</td>
<td>0.06</td>
</tr>
<tr>
<td>Ignition Loss</td>
<td></td>
<td>0.67</td>
<td>2.18</td>
<td>0.87</td>
</tr>
</tbody>
</table>

*nd = < detection limit

**Table 6.2:** Major oxide compositions of the granite samples from The University of Newcastle fused bead XRF analytical results

<table>
<thead>
<tr>
<th>Major Oxides</th>
<th>Moonbi Wt %</th>
<th>Error</th>
<th>Mossgiel Wt %</th>
<th>Error</th>
<th>Nambucurra Wt %</th>
<th>Error</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO$_2$</td>
<td>67.01</td>
<td>0.100</td>
<td>65.53</td>
<td>0.100</td>
<td>72.73</td>
<td>0.100</td>
</tr>
<tr>
<td>Al$_2$O$_3$</td>
<td>15.06</td>
<td>0.050</td>
<td>14.56</td>
<td>0.050</td>
<td>13.85</td>
<td>0.050</td>
</tr>
<tr>
<td>K$_2$O</td>
<td>4.31</td>
<td>0.013</td>
<td>3.77</td>
<td>0.012</td>
<td>4.24</td>
<td>0.012</td>
</tr>
<tr>
<td>Fe$_2$O$_3$</td>
<td>3.73</td>
<td>0.015</td>
<td>5.56</td>
<td>0.018</td>
<td>2.51</td>
<td>0.012</td>
</tr>
<tr>
<td>Na$_2$O</td>
<td>3.14</td>
<td>0.051</td>
<td>2.94</td>
<td>0.050</td>
<td>2.97</td>
<td>0.048</td>
</tr>
<tr>
<td>CaO</td>
<td>3.12</td>
<td>0.009</td>
<td>1.70</td>
<td>0.007</td>
<td>1.30</td>
<td>0.006</td>
</tr>
<tr>
<td>MgO</td>
<td>1.88</td>
<td>0.019</td>
<td>1.96</td>
<td>0.019</td>
<td>0.71</td>
<td>0.012</td>
</tr>
<tr>
<td>TiO$_2$</td>
<td>0.53</td>
<td>0.003</td>
<td>0.77</td>
<td>0.003</td>
<td>0.31</td>
<td>0.002</td>
</tr>
<tr>
<td>P$_2$O$_5$</td>
<td>0.24</td>
<td>0.004</td>
<td>0.20</td>
<td>0.004</td>
<td>0.18</td>
<td>0.003</td>
</tr>
<tr>
<td>MnO</td>
<td>0.07</td>
<td>0.000</td>
<td>0.08</td>
<td>0.000</td>
<td>0.05</td>
<td>0.000</td>
</tr>
<tr>
<td>SO$_3$</td>
<td>0.01</td>
<td>0.001</td>
<td>0.09</td>
<td>0.002</td>
<td>0.01</td>
<td>0.001</td>
</tr>
<tr>
<td>Ignition Loss</td>
<td>0.69</td>
<td></td>
<td>2.68</td>
<td></td>
<td>1.03</td>
<td></td>
</tr>
</tbody>
</table>
The approximate mineral compositions of the granite samples were determined using Rietveld quantitative X-ray diffraction (XRD) analysis and SIROQUANT™ V3 commercial software at AMDEL Limited laboratory. Known amounts of zinc oxide (ZnO) was added as internal standard to calculate the amorphous content in the samples. Figure 6.11 shows the XRD trace of the three samples with ZnO and Table 6.3 shows the approximate mineral compositions. It can be seen in the table that quartz, plagioclase feldspar, alkali feldspar, mica, and amorphous compound (most likely silica) are common to all the granite samples. Amphibole is present in the Moonbi sample but is absent in Mossiel and Nambucurra samples while chlorite is present in Mossiel and Nambucurra samples but is absent in Moonbi sample. Plagioclase feldspar has the highest concentration in the Moonbi sample while amorphous compound has the highest concentration in the Mossiel and Nambucurra samples.

Figure 6.12 shows the XRD trace of the three samples without ZnO internal standard analysed in the Electron Microscope and X-Ray Unit, Central Scientific Services, The University of Newcastle. The location and relative strength of the peaks are identical to the XRD trace with ZnO internal standard, and this shows the consistency and homogeneity of the Moonbi samples.
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Figure 6.11: Relative XRD trace of the three samples with ZnO internal standard, Nambucurra 1 (red), Moonbi (blue), and Mossgiel (green).

Figure 6.12: Relative XRD trace of the three samples without ZnO internal standard, Nambucurra 1 (red), Moonbi (blue), and Mossgiel (green).
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**Table 6.3:** Mineral compositions of the granite samples in wt % based on quantitative XRD analysis

<table>
<thead>
<tr>
<th>Composition</th>
<th>Moonbi</th>
<th>Mossgiel</th>
<th>Nambucurra</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amorphous Dis-ordered atoms</td>
<td>2</td>
<td>30</td>
<td>25</td>
</tr>
<tr>
<td>Quartz SiO$_2$</td>
<td>15</td>
<td>16</td>
<td>24</td>
</tr>
<tr>
<td>Plagioclase Feldspar*</td>
<td>NaAlSi$_3$O$_8$</td>
<td>30</td>
<td>23</td>
</tr>
<tr>
<td>Alkali Feldspar#</td>
<td>KAISi$_3$O$_8$</td>
<td>14</td>
<td>12</td>
</tr>
<tr>
<td>Mica X$<em>2$Y$</em>{4.6}$Z$<em>6$O$</em>{20}$(OH$_2$F)$_2$</td>
<td>17</td>
<td>8</td>
<td>20</td>
</tr>
<tr>
<td>Amphibole##</td>
<td>XY$_2$Z$_5$(Si,Al,Ti)$<em>8$O$</em>{22}$(OH,F)$_2$</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td>Chlorite*</td>
<td>(X$_3$Al)(AlSi$<em>3$)O$</em>{10}$(OH)$_8$</td>
<td>11</td>
<td>3</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

*Plagioclase best match of Albite

#Alkali feldspar possible match of Microline in Moonbi, possible mixture of Microline and Sanidine in Mossgiel and Nambucurara samples

**Mica in which X is K, Na, Ca or less commonly Ba, Rb or Cs; Y is Al, Mg, Fe or less commonly Mn, Cr, Ti, li, etc.; Z is chiefly Si or Al but also may include Fe$^{3+}$ or Ti

**Mica is most likely Muscovite

##Amphibole where X=Na, K, vacant; Y=Na, Ca, Fe$^{2+}$, Li, Mn$^{2+}$, 3+, Al, Mg; Z = Fe$^{3+}$, Mn$^{3+}$, Al, Ti$^{4+}$, Fe$^{2+}$, Li

##Amphibole possible match to Hornblende

*Chlorite where X=Mg, Fe, Ni, and Mn

*Chlorite possible match with Clinohlore-ferroan
6.3 Results and Discussion

6.3.1 Preliminary Batch CO\textsubscript{2}-Rock Interaction Experiment

Moonbi pulverised granite sample (194 g) loosely packed in the double ended flexible titanium cell was used in a preliminary batch experiment to determine the extent of CO\textsubscript{2}-rock interaction. The experiment was run at 35 MPa and 200\textdegree C simulated reservoir pressure and temperature, respectively. Figure 6.13 shows the concentration of elements dissolved in scCO\textsubscript{2} after 200\textdegree C and 35 MPa batch reactions. The figure shows that Ca, Fe, Mg, Al, and Si were dissolved in scCO\textsubscript{2} at concentrations lower than 2 parts per million by weight. Theoretically, granite should not dissolve in water-free scCO\textsubscript{2} as reported by Lin et al. (2008). The most probable explanation is the presence of H\textsubscript{2}O in the reaction. H\textsubscript{2}O is highly reactive in combination with CO\textsubscript{2}. It was suspected that the main source of H\textsubscript{2}O that contaminated the batch CO\textsubscript{2}-rock interaction experiments was the piston accumulator from where CO\textsubscript{2} was stored and transferred into the reactor. As mentioned earlier, the piston accumulator used H\textsubscript{2}O as the hydraulic fluid, which could possibly have leaked through the o-rings. Alternatively, the pore H\textsubscript{2}O content or mineral bound H\textsubscript{2}O in the granite sample may have also played a role (Hongfei Lin et al., 2007; Hongfei Lin, et al., 2008). H\textsubscript{2}O is highly soluble in scCO\textsubscript{2} at high temperatures and pressures. The studies done by Takenouchi and Kennedy (1964) showed that at 35 MPa and 200 \textdegree C, H\textsubscript{2}O is soluble up to 18\% by mole or ~8.24 \% by weight in scCO\textsubscript{2}.

It was planned to continue the experiment for another 30 days, but due to pressure transducer error, pre-mature depressurisation of the confining pressure caused the flexible titanium reactor to rupture. Consequently, the pulverised rock sample specimen was contaminated and wasted. Figure 6.14 shows the ruptured flexible titanium cell reactor.
6.3.2 Batch CO₂-Rock Interaction Experiments

The elemental composition of the 2% nitric acid sample solutions for batch CO₂-rock interaction experiments carried out at 20 MPa and simulated reservoir temperatures of 200°C and 250°C are presented in Figures 6.15 and 6.16, respectively. These results
show that Si, Ca, and Mg were dissolved in CO$_2$ and the concentrations changed from day one to day 15 with Ca and Mg concentrations decreasing over time. Na and K concentrations, on the other hand, increased significantly from day 1 to day 15 at a simulated reservoir temperature of 250$^\circ$C. At 200$^\circ$C however, Na and K concentrations remained unchanged. It should be noted that most of the analytical results were near the detection limit and/or at the lower end of the calibration standards used in the ICP-OES analysis.

The above results are contrary to the theoretical results from previous studies that showed granite, quartz, or biotite absolutely do not dissolve in water-free scCO$_2$ and therefore should not have been detected in the analysis (Hongfei Lin, et al., 2007; Hongfei Lin, et al., 2008). As stated earlier, it was possible that water was present in the CO$_2$ pumped from the piston accumulator. The CO$_2$ in the piston accumulator was kept at constant 20 MPa and 20$^\circ$C. At this pressure and temperature, the experimental data from the literature give 2.9% H$_2$O molar solubility (~1.2% by weight) in CO$_2$ (Spycher, Pruess, & Ennis-King, 2003). In addition, the mutual solubilities of scCO$_2$ and H$_2$O increase as the temperature and pressure increase. Figure 6.17 shows the mutual solubilities of H$_2$O and CO$_2$ as a function of pressure at 200$^\circ$C (top) and 250$^\circ$C (bottom) with expected 15-35% H$_2$O molar solubility in scCO$_2$ at 20 MPa.

To verify the possibility of H$_2$O being present in scCO$_2$, geochemical simulations were conducted to determine the theoretical concentrations of Si, Na, and K in an aqueous solution saturated with CO$_2$ in contact with the rock minerals using PHREEQC for Windows (Version 2) and Geochemist's Workbench (GWB Standard Release 9.0). PHREEQC is a computer program for geochemical calculations based on equilibrium chemistry of aqueous solutions interacting with minerals, gases, solid solutions, exchangers, and sorption surfaces (Parkhurst and Appelo, 1999). The capabilities of the PHREEQC program include (1) speciation and saturation-index calculations, (2) batch-reaction and 1D transport calculations, and (3) inverse modelling. Similarly, GWB Standard version is a set of software tools for balancing reactions, calculating activity diagrams, computing speciation in aqueous solutions, modelling reaction processes, and plotting the results of these calculations (Bethke and Yeakel, 2011). Due to the non-
availability of thermodynamic and kinetic data of amphibole (particularly hornblende) in the literature, its contribution to Si aqueous concentrations was ignored. Instead, the geochemical simulations only allowed possible dissolution of quartz, albite, k-felspar, mica, and amorphous silica which were the other major mineral compositions of Moonbi granite. The amorphous compound detected in XRD analysis of Moonbi granite was assumed amorphous silica.

The geochemical simulations performed were modelled assuming that minute quantities of H$_2$O are present in the CO$_2$ fluid stream interacting with the pulverised granite samples. On the basis of 25 g pulverised Moonbi granite (assumed 2.7g/cc density) inside the 18 ml reactor and considering the solubility of H$_2$O in CO$_2$ at 20 MPa and 20°C, the volume occupied by the fluid was calculated to be 8.74 ml from which ~0.096 g was H$_2$O and the rest was CO$_2$. The concentration of Si analysed from the 2% nitric acid solution was then recalculated assuming that it was all dissolved in the H$_2$O present in CO$_2$. Figure 6.18 presents the calculated aqueous Si concentration dissolved in scCO$_2$ (symbols) at different exposure times and the simulated equilibrium aqueous Si concentrations as a function of temperature (lines). The plot shows that at 200°C, the aqueous Si concentration was in equilibrium with the rock minerals after 1 day and apparently became oversaturated after 7 days. At 250°C, the aqueous Si concentration was still unsaturated after 1 day and became oversaturated after 7 days. Interestingly, the set of data points from different exposure times had the same trends. It was highly probable that more of the H$_2$O from the piston accumulator was accumulated in the reactor during day 7 until day 15 of the batch reaction. The high pressure CO$_2$ pump was intermittently operated to keep the system pressure constant. Theoretically, the dissolved H$_2$O in 20°C CO$_2$ fluid in the piston accumulator may have been transported through diffusion to the high temperature CO$_2$ fluid, which is unsaturated with respect to H$_2$O content. The H$_2$O solubility in CO$_2$ at 20 MPa and 200-250°C was 6.7% or more by weight compared with 1.2% by weight at 20°C. The extra H$_2$O in the reactor could bring the 7 and 15 days data points within the simulated equilibrium lines. In general, the aqueous solution "suspended" in scCO$_2$ was in local equilibrium with respect to Si concentration at 200°C and near equilibrium at 250°C. The aqueous Si content primarily came from the dissolution of amorphous silica based on the PHREEQC and GWB
simulations of aqueous Si equilibrium concentrations. Table 6.4 shows the saturation H$_2$O content in scCO$_2$ that could have existed during the CO$_2$-rock interaction batch experiments at different temperature and pressure conditions.

Ion exchange between albite and k-feldspar may control the aqueous Na and K concentrations in scCO$_2$. Figure 6.19 shows the simulated log (Na/K) ratio and the calculated aqueous log (Na/K) ratios from the batch experiments. The calculated aqueous log (Na/K) ratios from 200$^\circ$C and 250$^\circ$C batch experiments were unsaturated even after 15 days exposure time. The data points shown in Figure 6.19 implied the preferred dissolution of albite.

The simulated equilibrium log (Ca/Mg) ratio between calcite and magnesite minerals and the calculated aqueous log (Ca/Mg) ratio from the batch experiments are presented in Figure 6.20. Generally, the plot shows that the concentrations of aqueous Ca and Mg in scCO$_2$ were not controlled by the ion exchange between calcite and magnesite minerals. The plot shows that after 15 days, the Ca/Mg ratios were similar for batch experiments at 200$^\circ$C and 250$^\circ$C, which could be used to infer that the reactions between the fluid and mineral grains containing both Ca and Mg were inhibited. Those said mineral grains were most probably amphibole, particularly hornblende. It was possible that the by-products of the initial fluid-rock interactions formed a passive layer, effectively inhibiting further reactions (Sugama, Ecker, & Butcher, 2010, 2011).

Wet carbonation of granite at 250$^\circ$C and 17.3 MPa conducted by Sugama et al. (2010, 2011) showed a formation of K$_2$CO$_3$, Na$_2$CO$_3$, kaolinite-like clay compound, and amorphous SiO$_2$. In the same studies, the wet carbonation of hornblende formed MgCO$_3$, CaCO$_3$, and FeCO$_3$ as observed through XRD and FT-IR analysis. K$_2$CO$_3$ and Na$_2$CO$_3$ are highly soluble in H$_2$O while MgCO$_3$, CaCO$_3$, and FeCO$_3$ are less susceptible to dissolve in H$_2$O. The results from this study show that in fact, Na, K, Ca, Mg, and Si elements were present in the 2% nitric acid solution from the batch experiments. The presence of H$_2$O in scCO$_2$ used to react with the pulverised granite in the present study was therefore partly validated. The presence of H$_2$O in the scCO$_2$ was later confirmed with greater certainty in the flow-through experiments which will be discussed in the next section.
In the presence of H$_2$O in scCO$_2$, a reactive species intermediate was formed to facilitate carbonation of rocks as expressed in the following reactions (Sugama, et al., 2010, 2011)

\[
\text{CO}_2 + \text{H}_2\text{O} \leftrightarrow \text{HCO}_3^- + \text{H}^+ \leftrightarrow \text{CO}_3^{2-} + 2\text{H}^+ \tag{6.2}
\]

\[
2\text{NaAlSi}_3\text{O}_8 + \text{CO}_3^{2-} + 2\text{H}_+ \rightarrow \text{Na}_2\text{CO}_3 + \text{Al}_2\text{Si}_6\text{O}_{14}(\text{OH})_2 \tag{6.3}
\]

\[
2\text{KAlSi}_3\text{O}_8 + \text{CO}_3^{2-} + 2\text{H}_+ \rightarrow \text{K}_2\text{CO}_3 + \text{Al}_2\text{Si}_6\text{O}_{14}(\text{OH})_2 \tag{6.4}
\]

\[
\text{Ca}_2(\text{Mg,Fe,Al})_3(\text{Al,Si})_8\text{O}_{22}(\text{F,OH})_2 + 12\text{CO}_3^{2-} + 2\text{H}^+ \rightarrow 2\text{CaCO}_3 + 5\text{MgCO}_3 + 5\text{FeCO}_3 + \text{Al}_1\text{Si}_8\text{O}_{22} + 2\text{HF} \tag{6.5}
\]

Figure 6.21 shows the Moonbi pulverised granite used before and after the batch experiments. Comparison of the two images show no noticeable physical differences in the appearance of the treated and untreated pulverised granite samples when inspected by the naked eye. There were also no detectable changes in the mass (±0.01g precision) of the Moonbi pulverised granite sample before and after the batch experiments. However, the SEM analysis of the Moonbi pulverised granite before and after performing batch CO$_2$-rock interaction experiments at 20 MPa and 200°C showed signs of erosion in the surface of some of the minerals. Figure 6.22 shows the SEM images of the Moonbi pulverised granite before the batch experiments. The figure shows rough edges and rough mineral surfaces typical of unaltered and unreacted pulverised solid samples. Conversely, Figure 6.23 shows SEM images of Moonbi pulverised granite after the batch experiments. It shows rounded edges and pebbled like surfaces which are typical signs of erosions. This was possibly due to the formation of carbonates in the surface and the subsequent erosion and dissolution of the carbonates, particularly Na$_2$CO$_3$ and K$_2$CO$_3$ (Sugama, et al., 2010, 2011).
Figure 6.15: Element compositions of the 2% nitric acid sample solutions taken from 200°C and 20 MPa CO₂-rock interaction experiment using Moonbi pulverised granite.

Figure 6.16: Element compositions of the 2% nitric acid sample solutions taken from 250°C and 20 MPa CO₂-rock interaction experiment using the Moonbi pulverised granite.
Figure 6.17: Mutual Solubilities of H₂O and CO₂ as a function of pressure at 200 and 250°C. Source: Spycher & Pruess (2010).

Table 6.4: Water content of the CO₂ in the batch CO₂-rock interaction experiments

<table>
<thead>
<tr>
<th>CO₂-Rock Batch Interaction at 20 MPa</th>
<th>200°C</th>
<th>250°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight of granite</td>
<td>24.85</td>
<td>20.58</td>
</tr>
<tr>
<td>Volume of granite*, ml</td>
<td>9.20</td>
<td>7.62</td>
</tr>
<tr>
<td>Volume of fluid, ml</td>
<td>8.80</td>
<td>10.38</td>
</tr>
<tr>
<td>Initial weight of fluid#, g</td>
<td>8.00</td>
<td>9.43</td>
</tr>
<tr>
<td>Weight of fluid during experiment##, g</td>
<td>2.28</td>
<td>2.27</td>
</tr>
<tr>
<td>Initial water content^, g</td>
<td>0.0960</td>
<td>0.1132</td>
</tr>
<tr>
<td>Maximum water content during experiment^^, g</td>
<td>0.1533</td>
<td>0.4102</td>
</tr>
</tbody>
</table>

* assume 2.7 g/ml density  
# density of CO₂ at 20 MPa and 20°C, 0.9091 g/ml  
^ assumes saturated with water at 20 MPa and 20°C  
## density of scCO₂ at the specified temperature and pressure  
^^ assumes H₂O saturated at the specified temperature and pressure
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Figure 6.18: The simulated aqueous Si concentration as function of temperature and calculated aqueous Si concentration in scCO₂ from CO₂-rock interaction batch experiments at different exposure times.

Figure 6.19: The simulated equilibrium log of aqueous (Na/K) ratio as function of temperature and the calculated log of aqueous (Na/K) ratio from the batch CO₂-rock interaction experiments.
Figure 6.20: The simulated equilibrium log of aqueous (Ca/Mg) ratio as function of temperature and the calculated log of aqueous (Ca/Mg) ratio from the batch CO$_2$-rock interaction experiments.

Figure 6.21: Pulverised Moonbi granite before (left) and after the batch CO$_2$-rock interaction experiments.
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Figure 6.22: SEM images of the untreated pulverised Moonbi granite sample.
Figure 6.23: SEM images of pulverised Moonbi granite after 23 days exposure in the batch CO₂-rock interaction experiments at 20 MPa and 200 °C.
Table 6.5 summarises the major oxide compositions of the Moonbi pulverised granite before and after batch CO$_2$-rock interaction experiments at 20 MPa and 200°C. The major oxide compositions of the Moonbi pulverised granite before and after the batch experiments showed very small changes to the compositions of SiO$_2$, Al$_2$O$_3$, CaO, MgO, Fe$_2$O$_3$, Na$_2$O, and K$_2$O. The relative abundance of SiO$_2$ in the pulverised granite sample used in the batch experiments increased while the other oxides decreased when compared with the untreated samples. This observation was used to infer that minute amounts of albite (NaAlSi$_3$O$_8$), k-feldspar (KAlSi$_3$O$_8$), and hornblende (Ca$_2$(Mg,Fe,$\textnormal{Al})_5$(Al, Si)$_8$O$_{22}$OH$_2$) reacted with the fluid. This observation was also consistent with the previously discussed ICP-OES analytical results (Figure 6.15).

**Table 6.5: Major oxide compositions of untreated and treated pulverised Moonbi granite at 200°C and 20 MPa batch CO$_2$-rock interaction experiments**

<table>
<thead>
<tr>
<th>Major Oxide</th>
<th>Weight %</th>
<th>Unreacted</th>
<th>200°C 20 MPa</th>
<th>Error</th>
<th>% difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO$_2$</td>
<td></td>
<td>67.005</td>
<td>67.270</td>
<td>0.100</td>
<td>0.265</td>
</tr>
<tr>
<td>Al$_2$O$_3$</td>
<td></td>
<td>15.060</td>
<td>14.970</td>
<td>0.050</td>
<td>-0.090</td>
</tr>
<tr>
<td>K$_2$O</td>
<td></td>
<td>4.314</td>
<td>4.293</td>
<td>0.013</td>
<td>-0.020</td>
</tr>
<tr>
<td>Fe$_2$O$_3$</td>
<td></td>
<td>3.733</td>
<td>3.694</td>
<td>0.015</td>
<td>-0.039</td>
</tr>
<tr>
<td>Na$_2$O</td>
<td></td>
<td>3.137</td>
<td>3.114</td>
<td>0.052</td>
<td>-0.023</td>
</tr>
<tr>
<td>CaO</td>
<td></td>
<td>3.116</td>
<td>3.058</td>
<td>0.009</td>
<td>-0.058</td>
</tr>
<tr>
<td>MgO</td>
<td></td>
<td>1.877</td>
<td>1.853</td>
<td>0.019</td>
<td>-0.024</td>
</tr>
<tr>
<td>TiO$_2$</td>
<td></td>
<td>0.530</td>
<td>0.533</td>
<td>0.003</td>
<td>0.003</td>
</tr>
<tr>
<td>P$_2$O$_5$</td>
<td></td>
<td>0.244</td>
<td>0.234</td>
<td>0.004</td>
<td>-0.011</td>
</tr>
<tr>
<td>MnO</td>
<td></td>
<td>0.075</td>
<td>0.075</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>SO$_3$</td>
<td></td>
<td>0.012</td>
<td>0.012</td>
<td>0.001</td>
<td>0.000</td>
</tr>
<tr>
<td>Ignition Loss</td>
<td></td>
<td>0.69</td>
<td>0.69</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>99.79</td>
<td>99.79</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
6.3.3 Flow-Through Fluid-Rock Interactions: CO₂ versus H₂O

Flow-through fluid-rock interaction experiments using CO₂ and H₂O and pulverised Moonbi granite were conducted at reservoir conditions of 20 MPa and 250°C. The Si, Na, K, and Al concentrations of the fluid samples as a function of time are presented in Figures 6.24, 6.25, 6.26, and 6.27, respectively. The results indicate possible reactions between the H₂O and CO₂ streams and amorphous silica, albite, and k-feldspar. H₂O consistently dissolved more rock minerals compared with CO₂ stream as evidenced by higher Si, Na, K, and Al element concentrations as shown in Figures 6.24 to 6.27.

The Si concentrations at 0.05 ml H₂O/min flow rate was about 182 ppm after 10 days and about 172 ppm at a flow rate of 0.20 ml H₂O/min. CO₂ streams, on the other hand, recorded a maximum Si concentration of about 5 ppm on 0.20 ml CO₂/min flow rate. Figure 6.23 shows that the average Si concentration decreased as H₂O flow rate increased. This was due to the fact that at a higher H₂O flow rate, the residence time was shorter and therefore had less time for the fluid and the rock mineral to interact.

Moreover, H₂O was found to dissolve more K and less Na as its flow rate increased from 0.05 ml/min to 0.20 ml/min. Al concentration also decreased as H₂O flow rate increased. These observations could be used to infer that at a higher mass flow rate, H₂O dissolves more k-feldspar and less albite.

In the case of CO₂ flow, Na and K decreased while Al increased as the flow rate increased from 0.20 ml/min to 0.50 ml/min. As discussed earlier, the dissolution of Si, Na, K, Al, and other species in the CO₂ flow-through experiments is believed to be driven by the presence of H₂O in the CO₂ stream. This theory was further confirmed by weighing the 2% HNO₃ capture solution over time. An increase in the weight of the 20 ml HNO₃ capture solution was observed which is associated with H₂O leaked into the CO₂ stream from the piston accumulator. Figure 6.28 shows Si concentrations at CO₂ flow rate of 0.50 ml/min and the measured H₂O content (secondary y-axis) in ml/min. It can be seen that the water content varied from 0.5% to 5% of the total volumetric flow. Also, Si concentration in the fluid decreased as H₂O content in the flow increased. The
latter behaviour could be explained considering the inverse relationship between the flow rate and effective residence time of H₂O inside the reactor.

In addition, the presence of Na, K, and Al cations in the fluid samples suggested dissolution of albite (release of Na and Al) and k-feldspar (release of K and Al) in the reacting fluid. Figure 6.29 shows the simulated log of (Na/K) ratios and that of the fluids from the flow-through experiments. These results suggest that the fluid-rock interactions primarily favoured reaction with albite because Na/K is greater than 1. The H₂O-rock interaction was consistently below that of albite/k-feldspar ion-exchange equilibrium line. Moreover, the log of (Na/K) ratio at 0.05 ml H₂O/min approached the albite/k-feldspar ion-exchange equilibrium after 3 days while the 0.2 ml H₂O/min started near the equilibrium line and stabilised at well below the equilibrium line after 10 days. In the CO₂-rock interaction, the log of (Na/K) ratio was greater at higher flow rates and crossed the albite/k-feldspar ion-exchange equilibrium faster compared with that of the lower flow rates.

The plot of log (Na/K) ratio from the CO₂-rock interaction experiments and H₂O content in the CO₂ streams is presented in Figure 6.30. It shows that the log of (Na/K) ratios increased as the H₂O content increased. This direct relationship between the log of (Na/K) ratio and H₂O content indicates that the higher the H₂O content in the CO₂ stream, the greater the amount of albite that reacted with the fluid than the amount of k-feldspar reacted.

To gain a better insight into the thermodynamic state of the fluid-mineral equilibria, the above data were plotted in the Na-K-Mg ternary diagram proposed by Giggenbach (1988) and is presented in Figure 6.31. The Na-K-Mg ternary diagram is based on the thermodynamically stable feldspar end-member equilibrium reactions expressed as

\[
0.8 \text{ muscovite} + 0.2 \text{ clinochlore} + 5.4 \text{ silica} + 2 \text{ Na}^+ \leftrightarrow 2 \text{ albite} + 0.8 \text{ k-feldspar} + 1.6 \text{ water} + \text{ Mg}^{2+} \tag{6.6}
\]

\[
0.8 \text{ muscovite} + 0.2 \text{ clinochlore} + 5.4 \text{ silica} + 2 \text{ K}^+ \leftrightarrow 2.8 \text{ k-feldspar} + 1.6 \text{ water} + \text{ Mg}^{2+} \tag{6.7}
\]
Figure 6.31 shows that the fluids from the flow-through experiments are far from the equilibrium. The data from the H₂O-rock interaction experiments showed similar high Na levels consistent with the postulated preferential dissolution of albite. In the case of CO₂-rock interaction experiments, Na concentration levels increased while Mg concentration levels decreased, approaching the concentration levels of H₂O-only experiments. The above findings are consistent with the literature data reported by Kuncoro et al. (2010). Kuncoro et al. (2010) performed batch Na-Cl-H₂O-rock interaction experiments using 0.70 grams of drill cutting from Habanero 3 wells (Cooper Basin EGS project) and 90 ml 250 ppm NaCl solution. Their results showed preferential dissolution of albite and k-feldspar over quartz and other minerals indicating that albite and k-feldspar were the most reactive phase in the granite samples. As shown in Figure 6.32, Si concentrations levels reported by Kuncoro et al. (2010), however, were much lower (maximum of 67 ppm) than the flow-through experiments conducted in this study with an average of 175 ppm. That is because in Kuncoro's experiment, the circulation fluid was being replaced with fresh 250 ppm NaCl solution every 24 hours. Other factors contributing to the discrepancy include higher mass ratio of H₂O to rock sample (i.e. 90 g H₂O/0.70 g rock) used by Kuncoro et al. (2010) compared to the current study, which is 9 g H₂O to 25 g rock sample with total reactor volume of 18 ml. The ratio used in this study is more realistic as it represents a typical geothermal system in which the amount of rock available for the reaction is large compared with the flowing fluid. Figure 6.32 also shows that the Si concentration level declines over time. The slight decline in Si concentration is associated with the depletion of the starting rock materials. As the rock is being depleted, the surface area available for the reaction diminishes; therefore, less and less of the rock samples are dissolved.
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Figure 6.24: Average elemental Si concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.

Figure 6.25: Average elemental Na concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.
Figure 6.26: Average elemental K concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.

Figure 6.27: Average elemental Al concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.
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Figure 6.28: Si concentration with time in the CO$_2$-rock interaction flow-through experiment at 0.50 ml CO$_2$/min (left axis, red circles) and the calculated water content in the CO$_2$ flow (right axis, blue diamond).

Figure 6.29: Log of Na/K activity ratios with time in the outlet of the fluid stream from 20 MPA and 250°C flow-through experiments at different flow rates.
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Figure 6.30: Correlations of log of Na/K activity ratios (solid symbols) with the overall H$_2$O content in CO$_2$ flow (crossline symbols).

Figure 6.31: The Giggenbach ternary diagram of the fluids reacted with Moonbi granite sample at 20 MPa and 250°C.
Figure 6.32: The Si concentration of fluid samples from flow-through H₂O-rock interaction experiments and from that of Kuncoro et al. (2010) studies.
6.3.4 Flow-Through CO₂-H₂O-Rock Interactions

Flow-through experiments using pulverised granite from different sources with different mineral compositions were conducted to examine the fluid-rock interactions as a function of mineral composition. In Section 6.3.3, it was established that the CO₂ stream entering the reactor contained varying amounts of H₂O. The presence of H₂O has been taken into account in interpreting the data presented in this section.

The Si, Na, K, and Al element concentrations of the fluid samples from the flow-through fluid-rock interaction experiments using granites from Moonbi, Mossgiel, and Nambucurra are presented in Figure 6.33. Also presented in Figure 6.33 is the corresponding H₂O content of the CO₂ stream. The fluid samples from Nambucurra predominantly had the highest element concentrations followed by Mossgiel while Moonbi had the lowest element concentrations. Generally, the element concentrations followed the trend of H₂O content in the CO₂ stream. That is, the element concentrations increased as H₂O content increased. The average H₂O contents were 9.6%, 6.4%, and 2.7% for Nambucurra, Mossgiel, and Moonbi fluid samples, respectively.

To normalise the results regardless of H₂O content, the log of (Na/K) ratios were plotted against time (Figure 6.34). The equilibrium log (Na/K) ratios of albite/k-feldspar ion-exchange are also shown in Figure 6.34. It can be seen that Nambucurra and Mossgiel data were above the albite/k-feldspar ion-exchange equilibrium line while Moonbi was below the equilibrium line. A second run of the Moonbi flow-through experiment with a significantly higher average H₂O content (at about 18.5%) conclusively placed the Moonbi data points below the albite/k-feldspar equilibrium line. The difference was found to be related to the mineral compositions of the granite in the starting rock materials. Both Nambucurra and Mossgiel contained chlorite (clinochlore-ferroan) and no amphibole while Moonbi contained amphibole (hornblende) and no chlorite. Chlorites particularly clinochlore are phyllosilicate minerals containing Mg and Fe with the chemical formula (Mg, Fe)₅Al(Si₃Al)O₁₀(OH)₈. Hornblende is a complex isomorphous mixture of calcium-iron-magnesium silicate, aluminium-iron-magnesium silicate, and iron-magnesium silicate with a general chemical formula given as
(Ca,Na)_{2-3}(Mg,Fe,Al)_5(Al, Si)_{8.5}O_{22}(OH,F)_{2}. Hornblende can easily alter to chlorite and epidote. It was therefore possible that in the Nambucurra and Mossgiel experiments, the most reactive component was albite that released higher proportions of Na in the fluid compared with other elements since chlorite is already a secondary mineral. In Moonbi granite, albite competed with hornblende for interaction with the fluids. Figure 6.35 shows the Ca, Mg, and Fe element concentration from flow-through experiments using granites from different sources. As can be seen in Figure 6.35, Moonbi initially had higher Ca and Mg concentrations compared with Nambucurra and Mossgiel, presumably released from the interaction of the fluid with hornblende. Figure 6.35 also shows that Ca, Mg, and Fe concentrations decreased with time, indicating the formation of insoluble carbonate minerals. The insoluble carbonate minerals tend to form a passive layer that prevents further fluid-rock interactions (Sugama, et al., 2010, 2011).

The experimental data collected using Moonbi, Mossgiel, and Nambucurra were plotted on the Na-K-Mg ternary diagram (Figure 6.36). As Figure 6.36 shows, the fluid samples were far from the thermodynamic equilibrium, indicating that the residence time of the fluid in the reactor was not sufficient to reach equilibrium. The calculated residence time of the fluid in the 18 ml total reactor volume is 238 seconds.
Figure 6.33: Si, Na, K, and Al concentrations of the fluid samples from the flow-through experiments using granite from different sources. The H$_2$O content of the 0.20 ml/min fluid flow is shown at the bottom of the plot.
Figure 6.34: The log of \( \text{Na/K} \) ratio of the fluid samples from the flow-through experiments using granite from different sources.
Figure 6.35: Aqueous Ca, Mg, and Fe concentrations of the fluid samples from the flow-through experiments using granite from different sources.
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6.3.5 XRD and SEM Analyses

The XRD trace of pulverised Moonbi granites before and after CO\textsubscript{2} batch experiments at 20 MPa and 200\degree C to 250\degree C is presented in Figure 6.37. The XRD trace of the pulverised Moonbi granites before and after the batch CO\textsubscript{2}-rock interaction experiments practically have shown the same peaks and intensities. Similarly, the XRD trace analysis of pulverised Moonbi granites before and after the flow-through CO\textsubscript{2}-rock interaction experiments as well as before and after the flow-through H\textsubscript{2}O-rock interaction experiments at different flow rates showed no changes in peaks and intensities (Figures 6.38 and 6.39, respectively). These observations were consistent with the slow and steady dissolution of rock minerals in the pulverised granites.

Similar experiments were performed at a higher average H\textsubscript{2}O content of 18.5\% to investigate the influence of H\textsubscript{2}O content on the fluid-rock interaction. Figure 6.40 presents the XRD trace of treated samples collected at the inlet, middle, and outlet of the reactor and compares them with the untreated granite sample. The experiments were conducted using Moonbi pulverised granites. Figure 6.40 shows that the...
pulverised granites first in contact with the fluid mixture in the inlet section of the reaction cell were altered or converted into different minerals. The analysis of XRD peak and intensity indicated that amphibole (hornblende) was most likely converted to chlorite while albite XRD peaks almost disappeared. These observations were also consistent with the ICP-OES analysis of the fluids where Moonbi experiments showed initially high Ca and Mg concentrations, which is considered to be the artefact of the reaction of hornblende with CO$_2$-H$_2$O mixture and its alteration or conversion into chlorite. In describing the solid samples, an untreated granite sample simply refers to the original pulverised granite while treated granite samples refer to reacted granite used in batch or flow-through experiments.

The SEM analysis of the Moonbi granites from CO$_2$ flow-through experiment with high H$_2$O content is presented in Figure 6.41. Figure 6.41 shows that cavities and pits were formed on the mineral surfaces. These changes in the mineral surfaces were inferred to be due to the dissolution and precipitation of carbonate minerals.

The XRD analysis of the pulverised Mossgiel and Nambucurra granites used in the flow-through experiments are presented in Figures 6.42 and 6.43, respectively. Figure 6.42 shows that the Mossgiel pulverised granites from the CO$_2$ flow-through experiment showed weakened muscovite XRD peaks and to a lower extent weakened albite XRD peaks but essentially have a similar set of XRD peaks compared with the untreated granites. Figure 6.43 shows that the XRD trace of Nambucurra powdered granites did not change after the CO$_2$ flow-through experiments.
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**Figure 6.37:** The XRD trace of the pulverised Moonbi granites before (blue line) and after batch reactions at different temperatures (green and red lines).

**Figure 6.38:** XRD trace of pulverised Moonbi granites before (green line) and after flow-through experiments at 20 MPa and 250°C using different CO₂ flow rates (brown and purple lines). The CO₂ streams contain up to 5% H₂O content.
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**Figure 6.39:** XRD trace of pulverised Moonbi granites before (green line) and after flow-through experiments at 20 MPa and 250°C using different H₂O flow rates (orange and pink lines).

**Figure 6.40:** XRD trace of pulverised Moonbi granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO₂ flow rate (green, pink and orange lines show the xrd trace of granites from different sections of the reactor). The CO₂ stream contains an average of 18.5% H₂O content.
Figure 6.41: SEM image of untreated (top) and treated (middle and bottom) Moonbi granite from 20 MPa and 250°C flow-through experiments.
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**Figure 6.42:** XRD trace of pulverised Mossgeil granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO₂ flow rate (green and red lines).

**Figure 6.43:** XRD trace of pulverised Nambucurra granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO₂ flow rate (green and red lines).
6.3.6 Transport Properties

The pressure loss in the system was monitored by measuring the inlet and outlet pressures of the reactor during the flow-through fluid-rock interaction experiments. Temperature data were also collected to monitor and check the stability of the experiments. The pressure and temperature data collected from the flow-through experiments using Moonbi granites at CO$_2$ flow rate of 0.20 ml/min and 0.50 ml/min as well as the H$_2$O flow rates of 0.20 ml/min and 0.05 ml/min are presented in Figures 6.44-6.47, respectively. Moreover, the pressure and temperature data collected from the flow-through experiments using Nambucurra and Mossgiel granites at CO$_2$ flow rate of 0.20 ml/min are presented in Figures 6.48 and 6.49, respectively.

As Figure 6.44 shows, at the flow rate of 0.20 ml/min the pressure drop encountered using CO$_2$ was 276 kPa (40 psi). This pressure was almost half of the pressure drop of 620 kPa (90 psi) recorded for H$_2$O at the same flow rate. In fact, for the same pressure gradient, CO$_2$ volumetric flow rate was four times greater than the H$_2$O flow rate. In the flow-through experiments, pressure fluctuations were encountered as the flow was stopped intermittently to refill liquid CO$_2$ in the piston accumulator (1 litre volume). This in turn caused a drop in pressure during the refilling process. An analysis of the inlet and outlet pressures of the reactor and temperature data validated the prediction that CO$_2$ flow has a lower reservoir pressure loss than H$_2$O.

In general, the pressure drop initially increased and then dropped due to a gradual compaction of the unconsolidated granite samples. The fall in pressure continued until the flow stabilised and/or the dissolution of some rock minerals enhanced the permeability. An analysis of the pressure data also shows that as the flow rate increased the pressure drop increased. For example, the pressure increased from 276 kPa to 310 kPa as the CO$_2$ flow rate increased from 0.2 ml/min to 0.50 ml/min. The pressure drop from the Nambucurra experiment initially increased then declined to a level below that of the Moonbi experiments after 4 days while the trend from the Mossgiel experiment showed a higher pressure drop compared with that of the Moonbi experiment. Nambucurra granite had an average particle size of 52 microns, which was larger than the Moonbi pulverized granite particles (16 microns). The particles of the Mossgiel
sample had the smallest size of 6 microns. It follows that the larger the particle size of the pulverised granite, the lower the pressure drop. The relationship between the particle size (grain size) and the intrinsic permeability developed by Shepherd (1989) could explain the above trend

\[ k = cd^e \]  

(6.8)

where \( k \) is the intrinsic permeability, \( d \) is the particle diameter, \( c \) is a dimensionless constant, and \( e \) is between 1.65 to 1.85, inclusive. Equation 6.8 demonstrates that at a given fluid mass flow rate, the higher the permeability, the lower the pressure drop is.

**Figure 6.44:** The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO\textsubscript{2}/min flow Moonbi experiment.
Figure 6.45: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.50 ml CO₂/min flow Moonbi experiment.

Figure 6.46: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml H₂O/min flow Moonbi experiment.
Figure 6.47: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.05 ml H₂O/min flow Moonbi experiment.

Figure 6.48: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO₂/min flow Nambucurra experiment.
Figure 6.49: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO$_2$/min flow Mossgiel experiment.
6.4 Concluding Remarks

A customised fluid-rock interaction apparatus was designed and fabricated to conduct batch and flow-through experimental studies of pulverised granites with CO$_2$ and H$_2$O at pressures of up to 35 MPa and temperatures of up to 250°C. Granite samples from three Australian sources were used to represent the HDR reservoir formation. CO$_2$ and H$_2$O flow-through fluid-rock interaction experiments were conducted at 20 MPa and 250°C using different flow rates. Fluid samples collected were analysed using ICP-OES while the pulverised granite samples were analysed using XRF, XRD, and SEM analysis.

The batch and flow-through CO$_2$-rock interaction experiments were influenced by the H$_2$O content in the fluid stream. The H$_2$O content was found to have leaked from the piston accumulator, which used H$_2$O as hydraulic fluid. The presence of H$_2$O in the CO$_2$-rock interaction experiments made the fluid reactive and dissolved minute amounts of granite materials as evidenced by the existence of Si, Na, K, Al, and other elements in the fluid samples. It was observed that as the H$_2$O content increases, the concentrations of elements in the fluid sample also increase. The high H$_2$O content in the CO$_2$-rock interaction experiments enhanced the alteration or conversion of amphibole (particularly hornblende) into chlorite. The H$_2$O-rock interaction experiments, on the other hand, dissolved a higher amount of the granite material than that of CO$_2$-rock interaction experiments (i.e. about 175 ppm Si from H$_2$O-rock experiments versus less than 5 ppm Si from CO$_2$-rock experiments at 20 MPa and 250°C). The decrease of Ca, Mg, and Fe concentrations over time was considered to be due to the formation of insoluble carbonate minerals and formation of a passive layer that prevented further fluid-rock interactions. Generally, both CO$_2$ and H$_2$O flow-through experiments did not reach aqueous equilibrium concentrations. Also, the bulk weight and compositions of the granite material remained unchanged. An x-ray diffraction analysis of the pulverised granites showed that the bulk compositions before and after the flow-through experiments remained unchanged except in CO$_2$ flow-through experiments with high H$_2$O content. An SEM analysis of the pulverised granites from the CO$_2$-H$_2$O-rock experiments showed formation of pits and cavities in some of
the mineral surfaces which was associated with the dissolution and precipitation of carbonate minerals. Moreover, the analysis of the inlet and outlet pressures of the reactor and temperature data validated the prediction that CO\textsubscript{2} flow has a lower reservoir pressure loss than H\textsubscript{2}O.

A development of CO\textsubscript{2} and H\textsubscript{2}O based EGS will encounter reservoir conditions similar to what were studied here. In H\textsubscript{2}O based EGS, dissolution of rock minerals in the reservoir cannot be avoided, and precipitation of minerals in other parts of the reservoir formation and/or in the wells and piping system, therefore, should be addressed. The techniques used to address this issue are 1) inject H\textsubscript{2}O at high temperature and/or 2) use chemical technique (i.e. use of scale inhibitors or addition of acids). In CO\textsubscript{2} based EGS, H\textsubscript{2}O in the reservoir will eventually be displaced with anhydrous CO\textsubscript{2} and therefore, the problem associated with dissolution/precipitation of rock minerals is critical during the initial development of the field. However, the effect of CO\textsubscript{2}-H\textsubscript{2}O mixtures in carbon steel pipes and cements used in the wellbore assembly must be investigated to ensure the integrity of the injection and production wells.

The dynamic dissolution and precipitation of minerals in the reservoir will affect the overall performance and operational efficiency of EGS. Dissolution of minerals in the reservoir formation will enhance porosity/permeability, which will increase mass circulation, heat extraction, and ultimately power generation. Too much dissolution of minerals in fluid channels could also lead to fluid flow short circuiting, which in turn could result to lower heat extraction rate and lower power generation. Precipitation of minerals in the reservoir, on the other hand, will impede fluid flow therefore eventually decreasing power generation. However, if precipitation happens in the outer periphery of the reservoir beyond the production-injection areal coverage, it will actually seal the reservoir and minimize the overall fluid loss of the EGS operation. This will favour H\textsubscript{2}O based EGS where the availability of H\textsubscript{2}O resource is limited while it will minimize the ancillary benefit of carbon geosequestration for CO\textsubscript{2} based EGS.

Presently, reservoir simulations incorporating fluid-rock interactions can only be done in a very limited set of scenarios (i.e. 1D near wellbore dissolution/precipitation and porosity/permeability changes) due to simulator limitations. A field wide application of
fluid-rock interaction in reservoir simulations has not been applied to date due to computing power requirements and complexity of possible fluid-rock reaction permutations including the need to input thermodynamic and kinetic parameters of individual mineral equilibrium reactions. It is known that each geothermal field has its own unique set of geologic formations and with it unique rock mineral compositions/combinations.
Chapter 7: Conclusions and Recommendation

This chapter presents the conclusions and recommendations drawn from the integrated reservoir wellbore-power plant cycle modelling and fluid-rock interaction experiments and simulations. The first section presents the conclusions from the 1D, 2D, and 3D integrated reservoir-wellbore-power plant cycle model simulations. The conclusion from the fluid-rock interaction experiments and simulations is presented in Section 7.2. Recommendation for future work is presented in Section 7.3.

7.1 Integrated Reservoir-Wellbore-Power Cycle Modelling

Integrated reservoir-wellbore-power plant models were developed to simulate fluid flow from the injection wells passing through the reservoir and production wells, and into the surface power plant facilities. One dimensional (1D), 2D, and 3D reservoir models were developed to investigate fluid channel flow in fractured reservoir, homogeneous porous media in radial direction, "3D effects," and transient changes during production, respectively. The CO$_2$ based EGS power generation process was based on the thermosiphon concept where scCO$_2$ is used to drive the turbine for electrical power generation. The H$_2$O based EGS, on the other hand, was based on the binary power plant cycle concept with isopentane as the secondary working fluid.

Mass and energy balances on 1D and 2D integrated reservoir-wellbore-power plant cycle modelling were solved using Engineering Equation Solver (EES). The integrated 1D and 2D models were initially defined (boundary conditions) by reservoir pressure at the bottom of the production well, injection wellhead pressure and temperature, and reference wellbore and reservoir parameters. The simulation results from 1D and 2D integrated reservoir-wellbore-power plant cycle modelling only represent a steady state snapshot of the entire power production process. Thermal depletion of the reservoir and
Chapter 7: Conclusions and Recommendation

the associated changes in reservoir conditions were addressed in the integrated 3D reservoir-wellbore-power plant cycle modelling.

The 3D integrated reservoir-wellbore-power plant cycle modelling was carried out in two steps. The first step was the transient geofluid mass and heat flow rates calculations using TOUGH2 and ECO2N equation of state module. The second step was the coupled wellbore flow and power plant cycle modelling to calculate total exergy and power generation potential of CO$_2$ and H$_2$O based EGS using EES. The use of TOUGH2/ECO2N was validated and calibrated by replicating the simulation results obtained from previous 3D reservoir modelling studies done by Pruess (2008).

Below are findings of the integrated model simulations:

- Integrated 1D reservoir model simulations showed that generally, CO$_2$ mass flow rates were higher than H$_2$O while H$_2$O based EGS was found to have higher heat extraction rates, total exergy, and power generation potentials than CO$_2$ based EGS. These behaviours were found to be due to CO$_2$ thermodynamic properties being influenced by both temperature and pressure while H$_2$O was only strongly influenced by temperature. Generally, CO$_2$ has a lower density than H$_2$O, which led to a higher frictional loss in the well and higher CO$_2$ production wellhead pressure than H$_2$O. Furthermore, CO$_2$ has a low kinematic viscosity that allowed for higher CO$_2$ mass flow rates in the reservoir compared with H$_2$O.

- The low CO$_2$ density increased CO$_2$ well frictional loss more than that of H$_2$O as exemplified when the well surface roughness increased from 40 $\mu$m to 400 $\mu$m. The CO$_2$ mass flow rates decreased by 5.8-14.4 % while H$_2$O mass flow rates decreased by 1.1-3.4%. Precipitation of minerals in the well during injection/production is a common occurrence and can directly increase the surface roughness of the wells.

- The decrease in the injection to production well distance from 1000 m to 700 m increased reservoir pressure gradient that led to the increased CO$_2$ and H$_2$O mass flow rates by about 35 to 39% and 15 to 31%, respectively. The low CO$_2$
kinematic viscosity also meant that at the same reservoir pressure gradient increase, the CO\textsubscript{2} mass flow rate increase will be higher than that of \text{H}_2\text{O}.

- In the integrated 2D reservoir-wellbore-power plant model simulations, as the ratio of the number of production to injection wells increased, CO\textsubscript{2} and \text{H}_2\text{O} mass flow rates and heat extraction rates did not change. However, CO\textsubscript{2} based EGS total exergy and power output increased as the ratio production to injection wells increased due to the lower CO\textsubscript{2} frictional loss in the production well. The CO\textsubscript{2} total mass flow from the injection well is divided by the number of production wells therefore lower mass flow rate in each production wells and consequently lower frictional loss. Furthermore, the lower frictional loss in the production well resulted to higher wellhead production pressures. The maximum CO\textsubscript{2} based EGS power output increased from 8.9 MW to 12.1 MW (36% improvement) when the ratio of production to injection wells was changed from the doublet (1:1) to the five-spot (4:1) well configuration. \text{H}_2\text{O} based EGS power generation output remained the same at different production to injection well ratios.

- An analysis of the 3D reservoir model simulations showed that high CO\textsubscript{2} mass flow rates cause rapid thermal depletion of the reservoir, which could be avoided by producing only from the topmost layer of the reservoir. A stable 11 MW CO\textsubscript{2} based EGS power output could be generated for at least 25 years. However, the low 20\textdegree\text{C} injection bottom-hole temperature (~11\textdegree\text{C} at the surface) used in the simulation limits its application to colder regions of the world. Increasing the injection temperature to 25\textdegree\text{C} at the surface decreased the stable power output of CO\textsubscript{2} based EGS to 8 MW. In comparison, increasing the \text{H}_2\text{O} injection temperature to 70\textdegree\text{C} (outlet temperature of the \text{H}_2\text{O} leaving the binary power plant) gives a stable 9-10 MW \text{H}_2\text{O} based EGS power generation.

- Increase in reservoir temperature decreases CO\textsubscript{2} mass flow rate and increases heat extraction rate due to the increase in CO\textsubscript{2} kinematic viscosity and increase in CO\textsubscript{2} specific enthalpy change, respectively. Water mass flow rate and heat extraction rate, on the other hand, increase as reservoir temperature increases...
due to the decrease in H₂O kinematic viscosity and the combined effect of increase in mass flow rate and the increase in H₂O specific enthalpy change, respectively.

- The CO₂ mass flow rate decreases as reservoir pressure increases and was found to be related to the CO₂ minimum kinematic viscosity as a function of temperature at constant pressure: The minimum kinematic viscosity increases as pressure increases. The heat extraction rate of CO₂ based EGS also decreases as reservoir pressure increases due to the lower CO₂ specific enthalpy change at higher pressure. In contrast, reservoir pressure did not change H₂O mass flow rate and has a negligible effect on heat extraction rate. These were found to be due to the independence of H₂O kinematic viscosity and H₂O specific enthalpy on the range of pressure considered in this study.

- At one order of magnitude decreased in reservoir permeability, the CO₂ based EGS power output decreased by 27% (i.e. from 11 MW to 8 MW power output) while H₂O based EGS decreased by 67% (i.e. from 9.2 to 2.7 MW average power output). This clearly shows that CO₂ based EGS performs better than H₂O based EGS at low permeability reservoir.

- A reservoir performance analysis of CO₂ based EGS showed that thermal efficiency is constant regardless of mass flow rates at any given injection and reservoir conditions. For example, a 252 kg/s CO₂ injection produced a stable 9.5 MW power generation for up to 20 years while a 444 kg/s CO₂ injection produced 17.8 MW power generation stable only for up to 10 years. Both constant mass flow rates have the same 10.7% thermal efficiencies at 35 years of production period.

- A wellbore heat transport analysis in the 2D reservoir model showed that CO₂ temperature along the length of the injection wellbore was higher than adiabatic condition at time higher than one year. This high average CO₂ temperature increased CO₂ mass flow rates due to an increase in CO₂ density. In addition, CO₂ production wellhead temperature and pressure are also higher than adiabatic
Chapter 7: Conclusions and Recommendation

condition at large times (> 1 year), which in turn increase CO₂ heat extraction rates. The integrated 3D reservoir-wellbore-power plant cycle model simulations also showed that considering wellbore heat transport between the earth formation and the fluid increased CO₂ based EGS power generation output by 2.7-9.6%. Conversely, H₂O based EGS power generation output decreased by 2.7% due to lower the H₂O wellhead production temperature and pressure. This was found to be due to a higher H₂O heat loss in the wellbore owing to H₂O higher heat capacity.

The overall results from the integrated reservoir-wellbore-power plant cycle simulations showed that CO₂ based EGS power generation potential was comparable and sometimes at par with H₂O based EGS. The high CO₂ mass flow rate in the reservoir can compensate for the relatively low CO₂ heat capacity. However, a high CO₂ frictional loss in the well can have a detrimental effect on the power generation potential of CO₂ based EGS at high mass flow rates. A stable and sustainable power output over the plant lifespan of 35 years can be achieved with an overall CO₂ mass flow rate of approximately 200 kg/s (~50 kg/s per production well in a five spot well configuration).

7.2 Fluid-Rock Interaction at HDR EGS Conditions

A hydrothermal apparatus was designed and fabricated to perform batch and flow-through experimental studies of granite samples with CO₂ and H₂O at pressures up to 50 MPa and temperatures up to 400°C. The fluid and rock are contained in a double-ended all titanium reaction cell, and the wetted-parts are made of titanium metal to minimise corrosion and interference in the fluid-rock interaction. The fluid-rock interaction experiments were conducted at different simulated reservoir pressures (20 and 35 MPa) and temperatures (200 and 250°C) and were run for up to 15 days. The granite samples were sourced from Australian sources: (i) surface granite from Moonbi near the New England Highway and (ii) granite drill core samples from Mossgiel 1 and Nambucurra 1 wells in the Murray-Darling Basin, NSW. The granite samples were pulverised and
analysed for particle size distribution, element (Fused-bead XRF), and mineral (Rietveld quantitative XRD) composition analysis.

A preliminary batch CO$_2$-rock interaction experiment at 35 MPa and 200°C showed that Ca, Fe, Mg, Al, and Si were dissolved in CO$_2$ though the concentrations were less than 2 ppm. It was found to be due to the presence of H$_2$O leaked from the piston accumulator. Similarly, batch CO$_2$-rock interaction experiments at 20 MPa and 200-250°C showed dissolution of Si, Ca, Mg, Na, and K in the 2% NHO$_3$ capture solution due to the presence of H$_2$O in CO$_2$ charged into the reactor.

The outcome of the fluid-rock interaction model simulations and experiments are summarised below:

- Geochemical modelling performed to simulate aqueous solution saturated with CO$_2$ that is in contact with the rock minerals showed that the aqueous Si concentration was in equilibrium with the rock minerals after 1 day exposure. However, the log of (Na/K) ratios and log of (Ca/Mg) ratios showed that the fluids were far from albite – k-feldspar ion exchange equilibrium and calcite-magnesite equilibrium, respectively.

- X-ray fluorescence analysis of the pulverised Moonbi granites before and after batch CO$_2$-rock interaction experiments showed very small changes to SiO$_2$, Al$_2$O$_3$, CaO, MgO, Fe$_2$O$_3$, Na$_2$O, and K$_2$O major oxide compositions which were consistent with the dissolution/reaction of albite (NaAlSi$_3$O$_8$), k-feldspar (KAlSi$_3$O$_8$), and hornblende (Ca$_2$(Mg,F$^{1+},$ Al)$_5$(Al,Si)$_8$O$_{22}$OH$_2$). The observations were found to be consistent with the ICP-OES analytical results.

- Flow-through CO$_2$ and H$_2$O-rock interaction experiments at 20 MPa and 250°C showed dissolution of amorphous silica, albite, and k-feldspar. H$_2$O-rock interaction experiments were shown to dissolve more rock minerals than that of CO$_2$ run experiments. The Si concentrations from H$_2$O run experiments were unsaturated with respect to amorphous silica (~585 ppm saturation) at 170-180 ppm while CO$_2$ run experiments only had < 5 ppm. Dissolution of rock minerals
in the CO₂ run experiments were due to the presence of H₂O (~0.5% to 5% of the total flow) in the CO₂ stream.

- An analysis of the log of (Na/K) ratios and Na-K-Mg ternary diagram based on the thermodynamically stable feldspar end-member equilibrium reactions showed that the fluid from the flow-through experiments were far from the equilibrium. The relatively higher Na level showed preferential dissolution of albite over k-feldspar.

- The presence and/or absence of some minerals in granites were found to influence the composition of effluents from the flow-through CO₂-H₂O-rock interaction experiments (i.e., the presence of chlorite (clinochlore-ferroan) and absence of amphibole (hornblende) and vice versa). Hornblende can alter/convert to chlorite. In the Nambucurra and Mossgiel samples, the most reactive component was albite while in Moonbi, albite competed with hornblende for interaction with the fluids. Moonbi effluent fluids had higher Ca and Mg concentrations than that of Nambucurra and Mossgiel which was considered to be the product of the interaction of the fluid with hornblende. Moreover, the concentrations of Ca, Mg, and Fe decreased with time, which was interpreted to be due to the formation of insoluble carbonate minerals in the surface forming a passive layer preventing further fluid-rock interaction.

- The X-ray diffraction trace analysis of pulverised Moonbi granites before and after batch and flow-through fluid interaction experiments showed practically the same peaks and intensities. However, pulverised Moonbi granite from the CO₂ flow-through experiment with high H₂O content (average of 18.5%) showed that amphibole (hornblende) was converted to chlorite.

- Scanning electron microscope image analysis of granite samples exposed in the batch and flow-through CO₂-rock interaction experiments showed rounded edges, pebble-like surfaces, and formation of cavities (in flow-through experiments) which are signs of erosion and precipitation/dissolution. In comparison, SEM images of untreated/unreacted granite samples showed rough
edges and surfaces attributed to the grinding and milling process during preparation. The observed rounded edges, pebble-like surfaces, and formation of cavities were inferred to be due to the formation of carbonates in the surface and its subsequent erosion and dissolution (particularly Na$_2$CO$_3$ and K$_2$CO$_3$) to the fluid.

- The pressure loss data collected from the flow-through experiments validated the prediction based on Darcy's law that CO$_2$ fluid flow in the reservoir has a lower reservoir pressure loss than H$_2$O fluid flow. The pressure loss data also validated the correlation that particle size (diameter) directly influences intrinsic permeability, and that given the same fluid mass flow rate, a medium with larger particles size/diameter has a lower pressure loss.

The fluid-rock interaction experiments demonstrated that CO$_2$, even with substantial amounts of H$_2$O present, has a much lower tendency to dissolve rock minerals in the simulated reservoir conditions than H$_2$O dominated system; hence, there is a much lower tendency to precipitate minerals in other parts of the engineered geothermal system. Moreover, the formation of a passive layer of Ca, Mg, and Fe carbonate minerals can prohibit further fluid-interaction and dissolution of the rock minerals.

### 7.3 Recommendations

The integrated reservoir-wellbore-power plant cycle modelling shows that CO$_2$ based EGS can be optimised to achieve stable power generation outputs comparable to that of H$_2$O based EGS. However, an optimised operation of a CO$_2$ based EGS power generation process typically requires high CO$_2$ wellhead production pressures and high mass flow rates which in turn would need piping design with higher specifications. In this regard, a detailed engineering design and cost analysis are recommended to determine the economic advantages or disadvantages of a CO$_2$ based EGS over H$_2$O based EGS with binary plant power cycle. Design, optimisation, and fabrication of a supercritical CO$_2$ turbine should also be considered in future economic feasibility studies.
Due to the limitation of the current fluid-rock interaction apparatus, long fluid residence time inside the reactor is not possible. The actual residence time of the fluid in the geothermal reservoir may take up to several days, and it is possible that the fluid can reach equilibrium concentrations with respect to certain rock minerals. This may eventually affect the mineral saturation index of the fluid when it flows up the well and surface pipe facilities. It is therefore recommended that a series of connected reaction cells with sampling ports in between cells or reaction cells with relatively high volumetric capacity be constructed to study the evolution of the fluid-rock interactions from the simulated injection zone to the production zone.

In CO$_2$ based EGS, studies showed that H$_2$O may be present in the CO$_2$ stream even after several years of production which could lead to condensation of carbonic acids in the well. Condensation of carbonic acids could present potential problems to the integrity of the well and surface pipe facilities. It is therefore recommended to investigate CO$_2$-H$_2$O-carbon steel and CO$_2$-H$_2$O-concrete interactions to determine how the integrity of carbon steel well casings and cement bonding in CO$_2$ based EGS will be affected under “wet” operating conditions (i.e. the produced CO$_2$ is not completely dry and brine is present in the stream).


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Appendix I: Sample EES Codes

1D Reservoir Simulation Codes

"The code below solves primarily for fluid circulation mass flow rate for a given injection and reservoir temperature and pressure condition."

Procedure INJ(T,P,e,d,m,Z_n, S$: PE, P_fric, T_b)
"Procedure to calculate for injection bottom-hole pressure and temperature."
"The inputs are temperature, pressure, surface roughness, mass flow rate, well depth, calculation depth interval, fluid name while the output are pressure head gain, total frictional loss and bottom-hole temperature, respectively"

$COMMON m
Temp:=T
Pres :=P
h_0 = enthalpy(S$,t=temp, p=pres)

n = Z/Z_n
deltaP_fric:=0
i:= 0
press_PE:=0
Repeat
i:=i+1
den = density(S$, p=pres, h=h_0)
mu =viscosity(S$, p=pres, h=h_0)
Re = 4*m/(mu*PI*d)
x_1=(6.9/Re)+(e/(3.7*d))^1.11
y_1=log10(x_1)
z_1 =-1.8*y_1
f=1/z_1^2
pipe_fric = (8*f*Z_n*m^2)/(PI^2*den*d^5)
deltaP_fric:=deltaP_fric +pipe_fric
deltaP_PE =den*9.81*Z_n
press_PE:=press_PE +deltaP_PE
pres:=pres + deltaP_PE - pipe_fric
temp = temperature(S$, p=pres, h=h_0)
Until i>=n
PE:=press_PE
P_fric = deltaP_fric
T_bot = temp
End

Function RES(S$,T1,T2, P,L,Z_n, kA, m)
"reservoir pressure loss calculation"
"The inputs are fluid name, injection well bottom-hole temperature, reservoir temperature, reservoir pressure, reservoir length, calculation interval, permeability-area, and fluid mass flow rate"

$COMMON m,kA
Pres = P
delT=T2-T1
n = L/Z_n
t_inc = delT/n
i:=0
Appendix I: Sample EES Codes

\[ \text{delP} := 0 \]
\[ \text{Repeat} \]
\[ i := i + 1 \]
\[ \text{temp} = T1 + (i - 0.5) \times t \text{ inc} \]
\[ \text{den} = \text{density} \left( S$, t = \text{temp}, p = \text{pres} \right) \]
\[ \text{mu} = \text{viscosity} \left( S$, t = \text{temp}, p = \text{pres} \right) \]
\[ \text{delP}_\text{res} = m \times \text{mu} \times Z_n / \left( \text{den} \times kA \right) \]
\[ \text{pres} = \text{pres} - \text{delP}_\text{res} \]
\[ \text{delP} := \text{delP} + \text{delP}_\text{res} \]
\[ \text{Until } i \geq n \]
\[ \text{RES} = \text{delP} \quad \text{"reservoir pressure loss"} \]
\[ \text{End} \]

Procedure PROD(T,P,e,d,m,Z,Z_n,S$:P\_prod,T\_prod,MW,tot\_fric)
"Production well calculations: The inputs are temperature and pressure at the bottom of production well, surface roughness, fluid mass flow rate, well depth, calculation depth interval and fluid name while the outputs are production pressure and temperature, fluid production enthalpy, and total frictional loss, respectively."

\$\text{COMMON m} \]
\[ \text{Pres} := \text{P} \]
\[ \text{Temp} := \text{T} \]
\[ h_0 = \text{enthalpy} \left( S$, t = \text{temp}, p = \text{pres} \right) \]
\[ n = Z/Z_n \]
\[ d\_fric := 0 \]
\[ i := 0 \]
\[ \text{REPEAT} \]
\[ i := i + 1 \]
\[ \text{IF } \text{pres} > 0 \text{ THEN} \]
\[ \text{temp} = \text{temperature} \left( S$, p = \text{pres}, h = h_0 \right) \]
\[ \text{den} = \text{density} \left( S$, p = \text{pres}, h = h_0 \right) \]
\[ \text{mu} = \text{viscosity} \left( S$, p = \text{pres}, h = h_0 \right) \]
\[ \text{Re} = 4 \times m / (\text{mu} \times \text{PI} \times d) \]
\[ x1 = \left( 6.9 / \text{Re} \right) + \left( e / (3.7 \times d) \right)^{1.11} \]
\[ y1 = \log_{10} (x1) \]
\[ z1 = -1.8 \times y1 \]
\[ f = 1 / z1^{1.2} \]
\[ \text{pipe\_fric} = \left( 8 \times f \times Z_n \times m \times 2 \right) / (\text{PI}^2 \times \text{den} \times d^5) \]
\[ d\_fric := d\_fric + \text{pipe\_fric} \]
\[ \text{deltaP\_PE} = \text{den} \times 9.81 \times Z_n \]
\[ \text{pres} := \text{pres} - \text{deltaP\_PE} - \text{pipe\_fric} \]
\[ \text{ELSE} \]
\[ \text{pres} = 0 \]
\[ \text{temp} = (i - 1) \times Z_n \quad \text{"shows the distance from the bottom of the well where the flow ceased"} \]
\[ \text{goto} \ 100 \]
\[ \text{ENDIF} \]
\[ \text{UNTIL } i \geq n \]
\[ 100: \ P\_prod = \text{pres} \]
\[ \text{T\_prod} = \text{temp} \]
\[ \text{MW} = h_0 \]
\[ \text{tot\_fric} = d\_fric \]
\[ \text{End} \]

"Initial/Boundary Conditions"
\[ \text{P\_inj} = 7500000 \ [\text{Pa}] \quad \text{"injection pressure"} \]
\[ \text{P\_res} = 49050000 \ [\text{Pa}] \quad \text{"reservoir pressure"} \]
\[ \text{T\_inj} = 25 \ [\text{C}] \quad \text{"injection temperature"} \]
Appendix I: Sample EES Codes

T_res = 225 [°C]
d = 0.2315 [m]  "injection well diameter"
d2 = 0.2315 [m]  "production well diameter"
delL = 1000 [m]  "reservoir length"
delZ = 5000 [m]  "well depth"
Z_n = 25 [m]  "calculation interval"
kA = 0.00000021 [m^4]  "permeability-area"
k = 0.00004 [m]  "surface roughness"
S$ = 'steam_IAPWS' or S$ = 'carbondioxide'  "fluid name"

H_0 = enthalpy(S$, T=T_inj, P=P_inj)
call inj(T_inj,P_inj,k,d,m,delZ,Z_n,S$: PE, deltaP_fwell, T_bot)
deltaP_fres = RES(S$, T_bot,T_res, P_int,delL,Z_n, kA, m)
P_int = P_res + deltaP_fres
P_inj = P_int + deltaP_fwell - PE
call prod(T_res, P_res,k,d2,m,delZ,Z_n,S$: P_prod,T_prod,H_1, p_fric)
MW = (H_1 - H_0)*m/1000000  "Heat extraction rates in MW"

2D Reservoir Simulation Codes: Adiabatic

Condition

"The code used in this simulation is essentially the same as the 1D reservoir simulation code except that the code for reservoir pressure loss calculation was modified to suit 2D reservoir calculations. Below is the code used for 2D reservoir pressure loss calculation."

Function RES(S$,T1,T2, P,L,Z_n, kA, m,r, thck)
$COMMON m,kA
Pres = P
delT=T2-T1
n = L/Z_n
t_inc = delT/n
i:=0
delP:=0
r_n:=r
Repeat
i:=i+1
temp = T1+(i-0.5)*t_inc
den = density(S$,t=temp,p=Pres)
mu =viscosity(S$,t=temp,p=Pres)
delP_res = m*mu*LN((r_n+Z_n)/r_n)/(2*PI*den*kA*thck)
pres = pres-delP_res
delP:=delP+delP_res
r_n = r_n + Z_n
Until i>=n
RES = delP
End

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2D Reservoir Simulation Codes: With Wellbore Heat Transport Loss

Procedure INJ(T,P,e,d,m,Z,Z_n, S$: PE, P_fric, T_bot)
$COMMON m, k_c1, k_c2, k_e, time, G_g$
pres :=P	temp:=T
n = Z/Z_n
deltaP_fric:=0
i:= 0
pres_PE:=0
Repeat
i:=i+1
den = density(S$, p=pres, t=temp)
mu = viscosity(S$, p=pres, t=temp)
Re = 4*m/(mu*P^d)
x1 = (6.9/Re)+(e/((3.7*d))^1.11)
y1=log10(x1)
z1 = 1.8*y1
f=1/z1^2
pipe_fric = (8*f*Z_n*m^2)/(PI^2*den*d^5)
deltaP_fric:=deltaP_fric +pipe_fric
deltaP_PE =den*9.81*Z_n
pres_PE:=pres_PE +deltaP_PE
pres:=pres + deltaP_PE -pipe_fric
p_z[i] = pres
"Fluid temperature calculation at the injection well"
k_f = conductivity(S$, p=pres, t=temp)
Nu1=(f/8)*(Re-1000)*Prandtl(S$, p=pres, t=temp)
Nu2=1.07+12.7*(SQRT(f/8))*(((Prandtl(S$, p=pres, t=temp))^(2/3))
Nus=Nu1/Nu2
"Nusselt Number"
h =Nus*k_f/d
r1 = d/2
r2 = r1+0.0137795
r3 = r2+0.0333375
U_1 = (1/h)+(r1*Ln(r2/r1))/k_c2 +(r1*Ln(r3/r2))/k_c1
U = 1/U_1
"overall heat transfer coefficient"
diff = 10^(-6)
t_d = (diff*time)/r3^2
Temp_d = Ln(exp(-0.2*t_d)+(1.5-0.3719*exp(-1*t_d))*sqrt(t_d)) "dimensionless temperature"
enth = enthalpy(S$, p=pres, t=temp)
C_p = Cp(S$,p=pres, h=enth)
"specific heat of the fluid"
Lr1=2*PI/(C_p*m)
Lr2 =((r1*U*k_e)/(k_e+(r1*U*Temp_d)))
L_R = Lr1*Lr2
TH1=(1-exp(-1*1*Z_n*L_R))/L_R
TH2= G_g*((1*Z_n)-TH1)
Temp =T+TH2
Until i>=n
PE:=pres_PE
Appendix I: Sample EES Codes

P_fric = deltaP_fric
T_bot = temp
End

Function RES(S$, T1, T2, P, L, Z_n, kA, m, r, thck)
$COMMON m, kA
Pres = P
delT=T2-T1
n = L/Z_n
t_inc = delT/n
i:=0
delP:=0
r_n:=r
Repeat
i:=i+1
temp = T1+(i-0.5)*t_inc
den = density(S$, t=temp, p=Pres)
mu = viscosity(S$, t=temp, p=Pres)
delP_res = m*mu*LN((r_n+Z_n)/r_n)/(2*PI*den*kA*thck)
pres = pres-delP_res
delP:=delP+delP_res
r_n = r_n + Z_n
Until i>=n
RES = delP
End

Procedure PROD(T, P, e, d, Z, Z_n, S$: P_prod, T_prod, MW, fric_prod)
$COMMON m, k_c1, k_c2, k_e, time, G_g
m_p = m/4
Pres := P
Temp := T
n = Z/Z_n
deltaP_fric:=0
i:=0
REPEAT
i:=i+1
IF pres > 0 THEN
den = density(S$, p=pres, t=temp)
mu = viscosity(S$, p=pres, t=temp)
Re = 4*m_p/(mu*PI*d)
x1 = (6.9/Re) + (e/(3.7*d))^1.11
y1 = log10(x1)
z1 = -1.8*y1
f=1/z1^2
pipe_fric = (8*f*Z_n*m_p^2)/(PI^2*den*d^5)
deltaP_fric:=deltaP_fric+pipe_fric
deltaP_PE = den*9.81*Z_n
pres := pres - deltaP_PE - pipe_fric
"Fluid temperature calculation at the production well"
k_f = conductivity(S$, p=pres, t=temp)  "thermal conductivity of the fluid"
Nu1=1/(8)*(Re-1000)*Prandtl(S$, p=pres, t=temp)
Nu2=1.07+12.7*(SQRT(1/8))*(Prandtl(S$, p=pres, t=temp))^2/3
Nu=Nu1/Nu2  "Nusselt Number"
h = Nu*k_f/d  "heat transfer coefficient of the fluid"
r1 = d/2  "inner radius of the casing"
Appendix I: Sample EES Codes

\[ r_2 = r_1 + 0.0137795 \]

"outer radius of the casing"

\[ r_3 = r_2 + 0.0333375 \]

"outer radius of the cement"

\[ U_1 = \frac{1}{U_1} \]

"overall heat transfer coefficient"

\[ \text{diff} = 10^6 \]

"thermal diffusivity of the earth, m²/s"

\[ t_d = \frac{\text{diff} \times \text{time}}{r_3^2} \]

"dimensionless time"

\[ \text{Temp}_d = \ln(\exp(-0.2 \times t_d) + (1.5 - 0.3719 \times \exp(-1 \times t_d)) \times \sqrt{t_d}) \]

"dimensionless temperature"

\[ \text{Cp} = \text{Cp}(S$, p=p\text{res}, t=\text{temp}) \]

"specific heat of the fluid"

\[ L_{R_1} = 2 \pi / (\text{Cp} \times m_p) \]

\[ L_{R_2} = (r_1 \times U \times k_e) / (k_e + (r_1 \times U \times \text{Temp}_d)) \]

\[ L_R = L_{R_1} \times L_{R_2} \]

\[ T_{f_1} = (1 - \exp(((n-i) \times Z_n - Z) \times L_R)) / L_R \]

\[ T_{f_2} = G_g \times ((Z - ((n-i) \times Z_n)) - T_{f_1}) \]

\[ \text{Temp} = T - T_{f_2} \]

ELSE

\[ \text{pres} = 0 \]

\[ \text{temp} = (i-1) \times Z_n \]

goto 100

ENDIF

UNTIL i = n

100: \text{P}_{\text{prod}} = \text{pres}

\[ \text{T}_{\text{prod}} = \text{temp} \]

\[ \text{MW} = \text{enthalpy}(S$, t=\text{temp}, p=\text{pres}) \]

\[ \text{fric}_{\text{prod}} = \text{deltaP}_{\text{fric}} \]

End

"Initial/Boundary Conditions"

\[ \text{P}_{\text{inj}} = 9500000 \text{ [Pa]} \]

"reservoir pressure"

\[ \text{P}_{\text{res}} = 49050000 \text{ [Pa]} \]

"injection pressure"

\[ \text{T}_{\text{inj}} = 25 \text{ [C]} \]

"injection temperature"

\[ \text{T}_{\text{ambi}} = 25 \text{ [C]} \]

"earth ambient temperature"

\[ \text{T}_{\text{res}} = 200 \text{ [C]} \]

"reservoir temperature"

\[ d = 0.2315 \text{ [m]} \]

"injection well diameter"

\[ d_2 = 0.2315 \text{ [m]} \]

"production well diameter"

\[ \text{delL} = 700 \text{ [m]} \]

"well depth"

\[ \text{delZ} = 5000 \text{ [m]} \]

"reservoir length"

\[ Z_n = 25 \text{ [m]} \]

"calculation interval"

\[ \text{kA} = 50.0E-15 \text{ [m}^2\text{]} \]

"permeability of the reservoir"

\[ \text{thick} = 305 \text{ [m]} \]

"thickness of the reservoir"

\[ k = 0.00004 \text{ [m]} \]

"surface roughness"

\[ S$ = \text{carbondioxide'} or S$ = \text{steam_IAPWS'} \]

\[ k_e = 2.42 \]

"earth conductivity, W/m-k"

\[ k_c1 = 1.5 \]

"cement conductivity"

\[ k_c2 = 43 \]

"carbon steel conductivity"

\[ \text{Time} = 3153.6 \]

"time in second"

\[ G_g = (T_{\text{res}} - T_{\text{ambi}}) / \text{delZ} \]

"geothermal gradient"

\[ \text{call inj}(\text{T}_{\text{inj}}, \text{P}_{\text{inj}}, \text{k}, \text{d}, \text{m}, \text{delL}, \text{Z}_n, S$: \text{PE}, \text{deltaP}_{\text{fwell}}, \text{T}_{\text{bot}}) \]

\[ \text{P}_{\text{int}} = \text{P}_{\text{inj}} - \text{PE} - \text{deltaP}_{\text{fwell}} \]

\[ \text{deltaP}_{\text{fres}} = \text{RES}(S$, \text{T}_{\text{bot}}, \text{T}_{\text{res}}, \text{P}_{\text{int}}, \text{delL}, \text{Z}_n, \text{kA}, \text{m}, \text{d}/2, \text{thick}) \]

\[ \text{P}_{\text{res}} = \text{P}_{\text{int}} - \text{deltaP}_{\text{fres}} \]

\[ \text{call prod}(\text{T}_{\text{res}}, \text{P}_{\text{res}}, \text{k}, \text{d}, \text{m}, \text{delL}, \text{Z}_n, S$: \text{P}_{\text{prod}}, \text{T}_{\text{prod}}, \text{H}_1, \text{fric}_{\text{prod}}) \]

\[ \text{H}_0 = \text{enthalpy}(S$, t=\text{t_{inj}}, p=\text{p}_{\text{inj}}) \]

\[ S_0 = \text{entropy}(S$, t=\text{t_{inj}}, p=\text{p}_{\text{inj}}) \]

\[ S_1 = \text{entropy}(S$, t=\text{t_{prod}}, p=\text{p}_{\text{prod}}) \]

\[ \text{heat} = m \times (\text{H}_1 - \text{H}_0) / 1000000 \]

"Heat extraction rate in MW"
Appendix I: Sample EES Codes

\[ E_x = m\left((H_1 - H_0) - ((t_{inj} + 273.15) \cdot (s_1 - s_0))\right)/1000000 \text{ "Total exergy in MW"} \]

**CO₂ Power Cycle Simulation Code**

“This code calculates for power generation potential and total exergy of CO₂ based EGS Thermosiphon Power Cycle given CO₂ mass flow rate, injection and production pressures and temperatures.”

\[ \eta_t = 0.85 \quad \text{"turbine efficiency"} \]
\[ \eta_p = 0.70 \quad \text{"pump efficiency"} \]
\[ S$ = \text{"carbon dioxide"} \]
\[ P_0 = 30000000 \quad \text{"production pressure"} \]
\[ T_0 = 180 \quad \text{"production temperature"} \]
\[ P_2 = 950000 \quad \text{"injection pressure"} \]
\[ T_2 = 25 \quad \text{"injection temperature"} \]
\[ p_1 = p_2 \quad \text{"turbine outlet pressure"} \]
\[ h_0 = \text{enthalpy(S$, p = P_0, t = T_0)} \]
\[ s_0 = \text{entropy(S$, p = P_0, t = T_0)} \]
\[ s_1 = s_0 \]
\[ h_1 = \text{enthalpy(S$, p = p_1, s = s_1)} \]
\[ h_1 - h_0 = \eta_t \cdot (h_0 - h_1) \]
\[ T_1 = \text{temperature(S$, h=h_1, p=p_1)} \]
\[ h_2 = \text{enthalpy(S$, p = p_1, t = T_2)} \]
\[ s_2 = \text{entropy(S$, p = p_2, t = T_2)} \]
\[ \text{MW_e} = m\left(h_0 - h_1\right)/1000000 \quad \text{"power generated"} \]
\[ E_x = m\left((h_0 - h_2) - ((T_2 + 273.15) \cdot (s_0 - s_2))\right)/1000000 \text{ "total exergy"} \]

**Binary Power Plant Cycle Simulation Code**

“This code calculates for power generation potential and total exergy of H₂O based EGS Binary Power Cycle given H₂O mass flow rate, injection and production pressures and temperatures. Please refer to Figure 4.5 for subscript notation”

\[ \eta_p = 0.70 \quad \text{"pump efficiency"} \]
\[ \eta_t = 0.85 \quad \text{"turbine efficiency"} \]
\[ s$ = \text{"isopentane"} \]
\[ t_5 = 25 \quad \text{"injection temperature"} \]
\[ P_5 = 7500000 \quad \text{"injection pressure"} \]
\[ m_w = 51.3 \quad \text{"H₂O mass flow rate"} \]
\[ t_1 = 225 \quad \text{"production temperature"} \]
\[ P_1 = 4.979E+06 \quad \text{"production pressure"} \]
\[ \text{h}_1 = \text{enthalpy(steam IAPWS, t=t_1, p=p_1)} \]
\[ \text{s}_1 = \text{entropy(steam IAPWS, t = t_1, p=p_1)} \]
\[ \text{pinch} = 5 \quad \text{"pinch temperature"} \]
\[ P_a = 101325 \quad \text{"condenser pressure"} \]
\[ P_b = 2.793E+06 \quad \text{"circulation pump pressure"} \]
\[ \text{h}_a = \text{enthalpy(S$, p = P_a, x = 0)} \]
\[ \text{s}_a = \text{entropy(S$, p = P_a, x = 0)} \]
\[ \text{h}_b = \text{enthalpy(S$, p = P_b, s = s_a)} \]
\[ \eta_p \cdot (\text{h}_b - \text{h}_a) = (\text{h}_b - \text{h}_a) \]
Appendix I: Sample EES Codes

\[
\begin{align*}
T_b &= \text{temperature}(S\$, p = p_b, h = h_b) \\
S_b &= \text{entropy}(S\$, p = p_b, h = h_b) \\
T_a &= \text{temperature}(S\$, p = p_a, s = s_a) \\
h_d &= \text{enthalpy}(S\$, p = p_b, x = 0) \\
T_d &= \text{temperature}(S\$, p = p_b, x = 0) \\
s_d &= \text{entropy}(S\$, p = p_b, h = h_d) \\
h_e &= \text{enthalpy}(S\$, p = p_b, x = 1) \\
s_e &= \text{entropy}(S\$, p = p_b, x = 1) \\
h_{fs} &= \text{enthalpy}(S\$, p = p_a, s = s_e) \\
(h_e - h_f) &= (h_e - h_{fs}) * \text{eta}_t \\
T_f &= \text{temperature}(S\$, p = p_a, h = h_f) \\
s_f &= \text{entropy}(S\$, p = p_a, h = h_f) \\
x_f &= \text{quality}(S\$, h = h_f, p = p_a) \\
t_g &= t_b + \text{pinch} \\
h_g &= \text{enthalpy}(S\$, t = t_g, p = p_a) \\
s_g &= \text{entropy}(S\$, t = t_g, h = h_g) \\
h_f - h_g &= h_c - h_b \\
t_c &= \text{temperature}(S\$, p = p_b, h = h_c) \\
s_c &= \text{entropy}(S\$, p = p_b, h = h_c) \\
(h_e - h_d) * m_i &= (h_1 - h_2) * m_w \\
t_3 &= t_c + \text{pinch} \\
h_3 &= \text{enthalpy} (\text{steam}_{\text{IAPWS}}, t = t_3, x = 0) \\
s_3 &= \text{entropy} (\text{steam}_{\text{IAPWS}}, h = h_3, x = 0) \\
(h_2 - h_3) * m_w &= (h_d - h_c) * m_i \\
t_2 &= \text{temperature} (\text{steam}_{\text{IAPWS}}, h = h_2, x = 0) \\
s_2 &= \text{entropy} (\text{steam}_{\text{IAPWS}}, h = h_2, x = 0) \\
h_4 &= \text{enthalpy} (\text{steam}_{\text{IAPWS}}, p = p_1, t = t_5) \\
s_4 &= \text{entropy} (\text{steam}_{\text{IAPWS}}, p = p_1, t = t_5) \\
s_5 &= s_4 \\
h_{5s} &= \text{enthalpy} (\text{steam}_{\text{IAPWS}}, p = p_5, s = s_{5s}) \\
\text{eta}_p * (h_5 - h_4) &= (h_{5s} - h_4) \\
W_{wp} &= m_w * (h_{5s} - h_4) \\
W_o &= (h_e - h_f) * m_i \\
W_p &= (h_b - h_a) * m_i \\
W &= (W_o - W_p - W_{wp}) / 1000 \\
E_x &= (m_w * (h_{1} - h_{5}) * (1 - (t_{5} + 273.15) / (t_{1} + 273.15))) / 1000 \\
\end{align*}
\]

"energy balance at the turbine" \\
"energy balance at the recuperator" \\
"energy balance at the evaporiser" \\
"energy balance at pre-heater" \\
"injection pump power requirement" \\
"turbine power generated" \\
"circulation pump power requirement" \\
"net power generated in MW" \\
"Total exergy based on heat exchange in MW"
Appendix II: Sample PHREEQC Code

TITLE CO₂-H₂O-rock interaction
SOLUTION 1
    temp    20
    pH      7 charge
    units   mmol/kgw
    density 1
    -water  0.10488 # kg water
EQUILIBRIUM_PHASES 1
    CO₂(g)    0 196.25
SAVE Solution 1
END
REACTION_TEMPERATURE 1
    20 300 in 29 steps
EQUILIBRIUM_PHASES 2
    Albite    0 28.606 dissolve_only
    CO₂(g)    0 196.25 dissolve_only
    K-feldspar 0 12.5769 dissolve_only
    K-mica    0 5.309319 dissolve_only
    Quartz    0 62.4 dissolve_only
    SiO₂(a)   0 8.323 dissolve_only
Use Solution 1
SELECTED_OUTPUT
    -file Activity.txt   # file name
    -reset false
    -user_punc h true
    -temp
    -totals Si Na K Al Ca Mg
    -activities Na+ K+ Ca+2 Mg+2
USER_GRAPH
    -headings Temp Si Na K Al
    -chart_title "Dissolved Species"
    -axis_scale x_axis 0 300 50
    -axis_titles "Temp" "Concentration, ppm"
    -initial_solutions true
    -start
    10 graph_x TC
    20 graph_y tot("Si")*28.0843e3 tot("Na")*22.9898e3 tot("K")*39.102e3
tot("Al")*26.9815e3
    -end
Save Solution 2
END