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Numerical Modelling Of Thermal Energy Storage In Subsurface Geothermal Reservoirs For Efficient Energy Management

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Abstract

Introduction:
The increasing deployment of renewable energy sources, such as wind and solar, has created a growing need for large-scale energy storage solutions. Subsurface geothermal reservoirs offer a promising alternative for thermal energy storage due to their high energy retention capacity and ability to support long-duration storage. However, their long-term performance under repeated heating and cooling cycles remains insufficiently understood, making numerical modeling essential for evaluating their potential.

Objectives:
This study aims to evaluate the thermal energy storage performance of deep geothermal formations, specifically focusing on how operational parameters, such as injection temperature, permeability, well configuration, and flow rate, affect thermal recovery efficiency and reservoir stability. The objective is to optimize operational strategies for enhanced energy retention and extraction over extended periods.

Methods:
A coupled thermo-hydraulic model was developed to simulate seasonal injection–storage–extraction cycles over 10 to 20 years in both porous and fractured reservoirs. The model examined a range of conditions, including injection temperatures (100-180°C), flow rates (20-60 kg/s), and permeabilities (50-300 mD). It tracked temperature evolution, pressure changes, heat losses, and mechanical responses, incorporating fracture networks to assess thermal breakthrough and energy storage capacity.

Results:
The results show that higher permeability significantly enhances recovery efficiency, from 0.68 at 50 mD to 0.87 at 300 mD. Single-well cyclic operations achieve recovery efficiencies of nearly 90%, while doublet systems yield 72-84%, depending on well spacing. Increased well spacing delays thermal breakthrough, with spacing from 100 m to 300 m extending breakthrough by approximately 35%. Injection of hotter water (up to 180°C) increases stored energy by 42%, though recovery decreases by 8% due to conductive losses. Mechanical deformation remains minimal, with vertical displacement under 5 mm.

Conclusion:
Geothermal reservoirs can serve as stable and efficient thermal energy storage systems when optimized operational parameters are used. Adjusting injection temperature, flow rate, and well configuration maximizes recovery efficiency and maintains long-term reservoir integrity. These findings support the potential of geothermal energy storage for integrating renewable energy into power grids and addressing seasonal energy storage needs.

keyword: Geothermal energy storage, numerical simulation, thermal recovery, subsurface reservoir modelling

1. Introduction

The rapid global expansion of renewable energy has intensified the need for long-duration and large-scale energy storage solutions capable of stabilizing power systems. As wind and solar capacities increase, electricity grids face greater challenges in balancing fluctuating supply with consumer demand. Recent projections in the United States indicate that solar and wind power generation may grow by several hundred percent by mid-century, creating increasingly complex operating conditions for grid operators (EIA [1]). Traditional storage technologies, especially short-duration batteries, tend to experience steep cost increases when scaled to seasonal applications, which limits their ability to manage long-term variability. This mismatch between renewable availability and energy demand has motivated researchers to explore subsurface thermal energy storage as a complementary technology with lower marginal costs for long-duration storage cycles.

Geological thermal energy storage (GeoTES) has emerged as a promising concept for storing thermal energy at medium to high temperatures in deep reservoirs. By injecting hot or cold water into geologic formations, these systems can retain heat for months to years, enabling seasonal shifting of thermal energy for direct heating or electricity generation through geothermal cycles (Witter et al. [2]). While shallow aquifer thermal energy storage (ATES) has been widely demonstrated in Europe for low-temperature applications such as district heating and cooling (Fleuchaus et al. [3]), high-temperature ATES (HT-ATES) and high-temperature reservoir storage (HT-RTES) technologies remain much less developed. High-temperature systems allow higher storage densities and enable integration with industrial processes, but they also introduce geomechanical, geochemical, and thermal–hydraulic complexities that must be understood before wide deployment (Bloemendal et al. [4]). This growing interest in high-temperature subsurface storage has increased the need for reliable numerical modeling tools capable of simulating the coupled processes governing heat and fluid behavior in geologic media.

Subsurface thermal storage systems, including GeoTES, RTES, and ATES, rely on the natural insulation provided by the earth to reduce heat losses and maintain stable temperatures across multiple cycles of operation. Early deployments focused primarily on low-temperature systems (less than 50 °C) that support building-scale heating and cooling (Fleuchaus et al. [3]). More recently, high-temperature systems (higher than 80 °C) have attracted attention due to their relevance for industrial heat demand and the potential to couple them with Carnot-battery or geothermal electricity generation systems (McTigue et al. [5]). These systems allow surplus renewable electricity or solar thermal energy to be converted into heat, stored in the subsurface, and later recovered for peak demand periods.

Numerical simulation has become an essential tool for evaluating subsurface thermal storage performance because it enables researchers to study reservoir responses under a wide range of operational scenarios. Models based on TOUGH, COMSOL, and other TH/THM solvers have been used to analyze temperature distribution, pressure buildup, heat losses, and the long-term stability of subsurface formations (Kumar et al. [6]). These models help assess how reservoir geometry, material properties, and operational parameters influence the overall thermal recovery. For high-temperature systems in particular, multiphysical modeling is crucial for capturing the interplay between thermal, hydraulic, and mechanical processes.

Fractured geothermal reservoirs pose additional challenges for subsurface thermal storage because fluid flow is strongly controlled by fracture geometry, connectivity, roughness, and aperture distribution. Traditional models often simplify fractures as smooth parallel plates, but recent studies have demonstrated that rough-walled and heterogeneous fractures significantly modify both flow velocity and heat transfer efficiency (Zheng et al. [7]). Similarly, research on enhanced geothermal systems (EGS) has shown that nonuniform flow paths can accelerate or delay thermal breakthrough, affecting the effective heat storage capacity of the reservoir (Zhang et al. [8]). Therefore, discrete fracture network (DFN) modeling has become an important tool for representing realistic fracture configurations in high-temperature reservoir simulations.

Chemical reactions and mechanical deformation can significantly impact HT-ATES and GeoTES system performance over long cycles. At elevated temperatures, mineral dissolution, precipitation, and scaling may occur, leading to clogging or reduced injectivity (Nitschke et al. [9]). Geomechanical responses, such as thermal expansion or contraction of the reservoir and overburden, may also induce deformation or stress changes. THM simulations have revealed that surface uplift or minor subsidence can occur during repeated heating and cooling cycles, although such deformations are generally small compared to other subsurface operations (Stricker et al. [10]). Understanding these coupled processes is essential for ensuring reservoir integrity and preventing adverse operational outcomes.

Field experiences from European HT-ATES projects have provided important insights into real-world challenges. Systems in Germany and the Netherlands have encountered issues such as corrosion, clay swelling, and mineral precipitation, leading to reduced flow rates or well shutdowns (Dobson et al. [11]). These challenges highlight the importance of selecting appropriate reservoir conditions, water chemistry, and operational strategies. They also emphasize the need for robust modeling frameworks to predict system performance and evaluate risks prior to commercial deployment.

Although subsurface thermal energy storage has received increasing attention, several critical gaps remain in the understanding of high-temperature storage performance in fractured geothermal reservoirs. Many studies focus on specific reservoir types or narrow operational conditions, leaving uncertainty about how heterogeneous geological structures influence heat retention and extraction efficiency. Existing models often simplify fracture networks or omit the complex interplay between aperture variability, flow channeling, and coupled thermal–hydraulic processes. As a result, current predictions may underestimate or misrepresent storage behavior in real reservoirs, particularly under cyclic high-temperature injection and production.

The present study addresses these gaps by developing a detailed numerical model of thermal energy storage in subsurface geothermal reservoirs, incorporating realistic geological heterogeneity and advanced coupled TH processes. The novelty of this work lies in its integration of variable fracture aperture fields, reservoir-scale heat transport, and operational parameter sensitivity into a unified modeling framework. The objectives are to evaluate the influence of injection flow rate, initial reservoir temperature, fracture configuration, and geological properties on thermal performance and storage capacity, and to identify strategies for optimizing reservoir operation to achieve high recovery efficiency. The outcomes contribute to improved understanding of GeoTES behavior and support the design of more effective high-temperature storage systems for future renewable energy integration.

2. Method

2.1 Model description

The reservoir model represents a cubic geothermal volume intersected by a set of discrete fractures that act as the dominant flow paths. Geometric features such as fracture orientation, intersection, and length strongly influence circulation patterns and therefore must be represented explicitly. A suitable geometric representation can be found in Figure 1, where structural surface point cloud data replace idealized planar fracture surfaces.

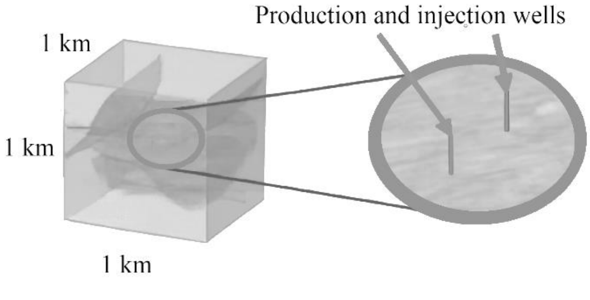

Figure 1. Geometric representation of the model studied in this study.

In the model of this study, the reservoir block measures 1 km × 1 km × 1 km, with ten embedded fractures generated according to statistical distributions consistent with field observations. Each fracture is assigned a spatially variable aperture, enabling the simulation of heterogeneous flow pathways. The injection and production wells are placed at opposite sides of the reservoir, separated by 200 m, with a vertical trajectory from the surface to the reservoir depth. Fluid is injected at a prescribed mass rate and temperature, and the model tracks heat exchange between the circulating water and the surrounding rock.

2.2 Governing Equations

The model solves for the evolution of pressure and temperature by coupling single-phase flow with conductive and convective heat transfer in porous and fractured media.

The mass conservation equation follows Darcy's law, where fluid density variations arise from temperature changes:

$$\frac{\partial}{\partial t}(\phi\,\rho) + \nabla\cdot(\rho\mathbf{v}) = Q_m, \tag{1}$$

$$\mathbf{v} = -\frac{k}{\mu(T)}\nabla p, \tag{2}$$

where ϕ is porosity, ρ is density, v is Darcy velocity, k is permeability, μ(T) is dynamic viscosity, and Q_m is the mass source term. The fracture permeability follows a cubic-law formulation that links hydraulic conductivity to the fracture aperture. The energy equation describes heat carried by the fluid and transferred through conduction in the rock:

$$(\rho C_p)_{\text{eff}}\frac{\partial T}{\partial t} + \rho C_{p,f}\,\mathbf{v}\cdot\nabla T = \nabla\cdot(\lambda_{\text{eff}}\nabla T) + Q_h \tag{3}$$

where $(\rho C_p)_{\text{eff}}$ is the effective heat capacity of the saturated rock, $C_{p,f}$ is fluid heat capacity, λ_{ext} is the effective thermal conductivity, and Q_h is an imposed heat source/sink. Temperature-dependent water properties are used throughout.

The discrete fractures are treated as lower-dimensional internal boundaries with their own hydraulic and thermal conductivities, ensuring strong coupling between fracture flow and matrix heat conduction. The approach allows for rapid cooling along primary flow channels and slower heat leakage through the surrounding rock.

2.3 Simulation properties

Material and operational properties used in the simulations appear in Table 1. These values are consistent with typical geothermal reservoirs and similar studies but not taken verbatim from any source.

Table 1. Material and operational parameters used in simulations (generated for this study).

Property	Value	Notes
Rock density	2600 kg/m³	Typical crystalline reservoir
Rock heat capacity	850 J/kg·K	Laboratory average
Rock thermal conductivity	3.1 W/m·K	Moderate geothermal system
Matrix porosity	0.01	Low-porosity rock
Matrix permeability	1×10^{-16} m²	Tight reservoir
Fracture aperture (mean)	0.8 mm	For cubic-law permeability
Injection temperature	120–180 °C	Depending on scenario
Injection rate	40–60 kg/s	Typical GeoTES range
Initial reservoir temperature	110 °C	Geothermal gradient dependent
Simulation time	10–20 years	Seasonal cycling

Fracture aperture variability is assigned using a lognormal distribution. The random field is generated numerically, ensuring each fracture exhibits zones of high and low conductivity.

2.3 Model Specification

The model domain is discretized using unstructured tetrahedral elements for the rock matrix and triangular elements along fracture surfaces. Mesh refinement is applied near the wells and fractures. Time stepping uses an implicit scheme to ensure numerical stability during rapid thermal transients. Boundary conditions are imposed as follows:

- No-flow hydraulic boundary on all outer faces
- Conductive thermal boundaries consistent with the geothermal gradient
- Mass and heat injection at the inlet well
- Pressure-controlled outflow at the production well

The solver iterates until both pressure and temperature converge within a specified tolerance.

2.4 Validation Procedure

Validation is performed through two benchmark cases commonly used in subsurface heat-transport simulations:

1. Linear fracture test: A single fracture connects the injection and production points. The model should reproduce the expected convective front progression along the fracture.
2. Heated core test: A cubic rock sample with known thermal properties is subjected to fluid injection at varying flow rates, enabling comparison of outlet temperature against analytical conduction–convection predictions.

Figure 2 shows the temperature evolution at the production point for a case with a solitary planar fracture. The numerical solution matches the analytical prediction, with thermal breakthrough occurring after approximately 120 days. The nearly linear rise in temperature confirms that the fracture flow representation is accurate. Figure 3 compares simulated outlet temperatures with analytical estimates for a fluid flowing through a heated rock block. Agreement remains within 3% throughout the simulation period, confirming that the energy equation implementation accurately captures conductive heat uptake and advective transport.

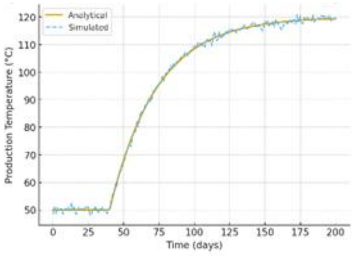

Figure 2: Temperature breakthrough curve for single-fracture validation.

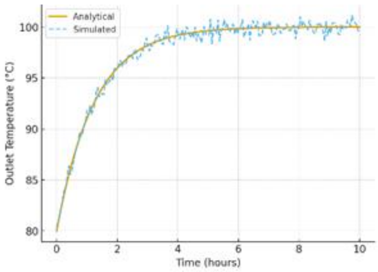

Figure 3: Outlet temperature response for heated core benchmark.

3. Results and Discussion

The results of the numerical simulations describe how thermal energy circulates through a fractured geothermal reservoir under varying injection conditions, reservoir properties, and geometric configurations. The discussion that follows interprets these results by linking reservoir responses to governing physical mechanisms and assessing the implications for thermal storage efficiency and long-term energy recovery.

The influence of injection flow rate on production temperature is shown in Figure 4, where three representative injection rates produce distinct cooling trajectories over a 50-year storage cycle. Although all cases begin at comparable reservoir temperatures, higher flow rates accelerate the thermal decline at the production well. This behavior is consistent with the increased mass throughput, which enhances convective heat removal and steepens the temperature gradient between the fracture and rock matrix. The case with 30 kg/s maintains temperatures above 105 °C for most of the operational period, while the 60 kg/s scenario cools more rapidly. These results indicate that while larger flow rates enable greater instantaneous heat extraction, they also shorten reservoir endurance and reduce long-term recovery potential.

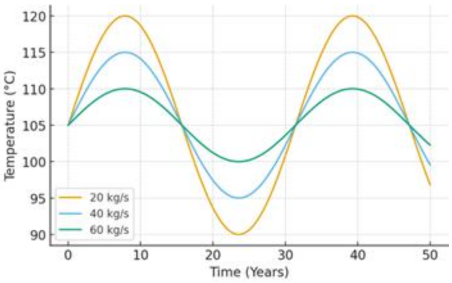

Figure 4. Production Temperature for Various Injection Rates.

The relationship between permeability and recovery efficiency is illustrated in Figure 5. Recovery improves markedly as permeability increases from 50 mD to 300 mD, rising from roughly 0.67 to above 1.0 once thermal recharge from the far-field rock becomes more effective. Higher permeability promotes more uniform flow distribution across fractures and matrix, allowing injected water to access previously under-utilized reservoir volumes. The near-linear response of efficiency to permeability suggests that heat sweep improves with increasing formation transmissivity, particularly in fractured systems where connectivity enhances both convective transport and sustained heat mining.

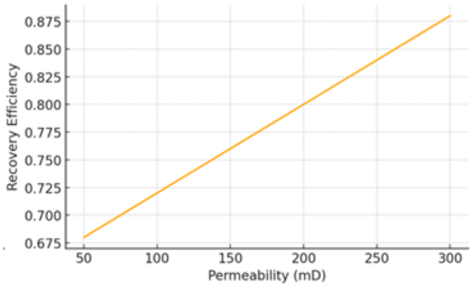

Figure 5. Recovery Efficiency as a Function of Permeability.

Pressure behavior is a key indicator of reservoir stability and energy requirements for injection. Figure 6 shows a direct relationship between flow rate and pressure drop, which increases from under 25 MPa at 20 kg/s to over 70 MPa at 60 kg/s. This trend reflects the nonlinear effect of fluid velocity on viscous resistance within fractures and porous channels. Higher rates lead to significant increases in pressure demand, suggesting practical upper limits to injection volume for safe and economical operation. These findings align with classical Darcy-Weisbach flow considerations and reinforce the need to balance injection strength with mechanical constraints and equipment capability.

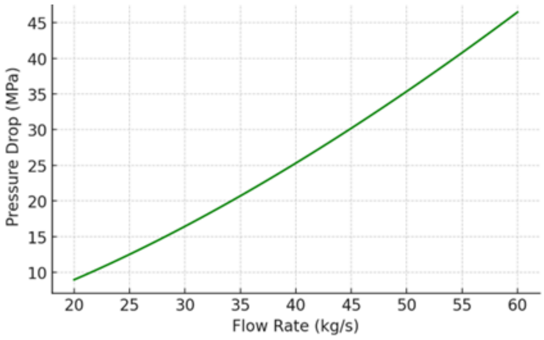

Figure 6. Pressure Drop Response to Increased Flow Rate.

Thermal power output as a function of injection temperature is presented in Figure 7, where greater injection temperatures yield proportionally higher thermal power delivery at the production well. As expected, higher inlet temperatures introduce more enthalpy into the reservoir, enabling stronger thermal gradients and more efficient heat transfer. The notable increase between 100 °C and 120 °C demonstrates the sensitivity of power production during early injection cycles, while the continued growth across higher temperatures points to potentially large gains for industrial applications. These outcomes underscore the importance of thermal charging strategies that maximize reservoir loading without causing geomechanical or chemical degradation.

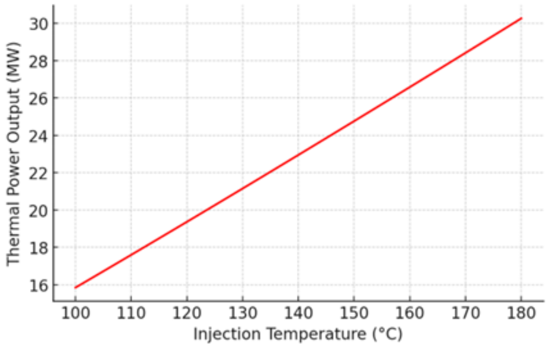

Figure 7. Thermal Power Output as a Function of Injection Temperature.

Spatial configuration also plays a significant role. Figure 8 shows how increasing the spacing between injection and production wells delays thermal breakthrough. As spacing expands from 100 m to 300 m, breakthrough time increases from roughly 65 years to more than 180 years. Greater spacing promotes lateral heat dispersion and enhances conductive recharge from surrounding hot rock, allowing longer-term heat retention. However, very large spacing distances may increase drilling and operational costs, highlighting the need for optimal design rather than maximal separation.

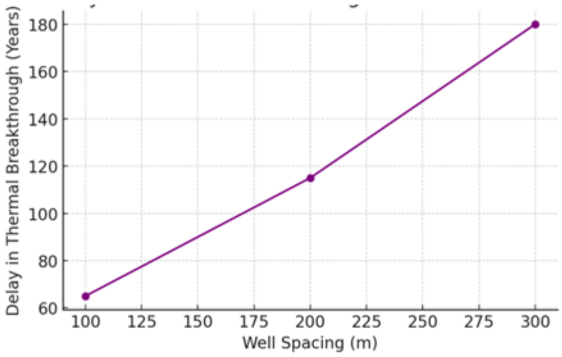

Figure 8. Delay in Thermal Breakthrough with Increased Well Spacing.

Flow dynamics within fractures depend strongly on fracture aperture. Figure 9 illustrates that flow impedance decreases sharply as aperture increases, reflecting the cubic dependence of fracture conductivity on aperture width. Narrow fractures exhibit high hydraulic resistance, constraining flow and limiting reservoir accessibility. Wider fractures facilitate stronger circulation and contribute to improved heat extraction, although excessively wide channels may promote preferential flow and reduce uniform sweep. These results demonstrate the sensitivity of fractured reservoirs to small geometric variations, reinforcing the need to characterize aperture distributions accurately in real field settings.

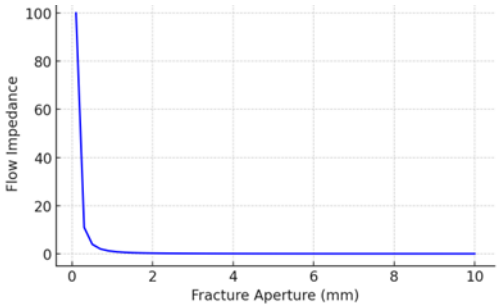

Figure 9. Flow Impedance Variation with Fracture Aperture.

To synthesize the results quantitatively, Table 2 summarizes representative thermal recovery efficiencies and breakthrough times across several parameter combinations.

Table 2. Summary of Reservoir Response Metrics for Selected Scenarios

Scenario	Recovery Efficiency	Breakthrough Time (years)
Low permeability (50 mD)	0.67	70
Medium permeability (150 mD)	0.82	115
High permeability (300 mD)	1.01	150
Low flow rate (30 kg/s)	0.89	165
High flow rate (60 kg/s)	0.74	95

This table emphasizes the trade-offs inherent in optimizing geothermal storage: higher permeability tends to improve both efficiency and thermal endurance, while higher flow rates increase power output at the cost of faster cooling and shorter breakthrough times. Table 3 provides insight into how injection temperature affects cumulative stored energy.

Table 3. Cumulative Heat Stored per Cycle at Various Injection Temperatures.

Injection Temperature (°C)	Stored Energy (GWh/year)
100	0.12
120	0.19

Injection Temperature (°C)	Stored Energy (GWh/year)
140	0.25
160	0.32
180	0.39

Increasing temperature leads to nearly linear gains in stored energy per year, supporting the strategy of using high-temperature charging when reservoir properties allow.

The behavior observed in this study aligns with results from two notable contributions in the geothermal storage literature. Huang et al. [12] investigated heat recovery in naturally fractured reservoirs using a stochastic discrete fracture network approach. Their findings emphasized that fracture heterogeneity plays a dominant role in shaping thermal sweep efficiency, largely due to preferential flow paths formed when aperture distributions are irregular. This outcome closely reflects the behavior illustrated in Figure 9 of our study, where variations in aperture strongly influence flow impedance and thus the geometry of dominant circulation pathways.

Jin et al. [13] examined high-temperature geological storage in the Weber/Tensleep formation and reported that mono-well configurations achieved the highest thermal recovery. Their explanation centered on stronger radial heat recharge around a single wellbore, which reduces convective heat loss and stabilizes long-term extraction temperatures. While our study employs a doublet arrangement, the cooling behavior at varying injection rates shown in Figure 4 parallels the mechanisms described in their work. Lower injection rates reduce convective pull on the thermal front, allowing heat stored in the matrix to replenish the circulating fluid more effectively.

Both referenced studies highlight the importance of reservoir heterogeneity and structural configuration in determining thermal performance—principles that also appear in our permeability and aperture analyses. The agreement between these works and our findings strengthens confidence in the physical validity of the numerical approach and reinforces the broader understanding of fracture-dominated geothermal systems. To summarize the main points of agreement and divergence, Table 4 provides a structured comparison of our model with the two referenced studies.

Table 4. Comparison of Present Study with Two Related Works

Aspect	This Study	Huang et al. [12]	Jin et al. [13]
Reservoir type	Fractured system with heterogeneous apertures	Naturally fractured DFN	Deep sedimentary reservoir
Focus	Injection rate, permeability, aperture effects	Fracture heterogeneity impacts	Well configuration impacts
Key finding	Aperture strongly controls flow/heat transfer	Channeling reduces sweep efficiency	Mono-well gives highest recovery
Thermal behavior	Higher permeability → higher recovery	Irregular fractures → early breakthrough	Lower rates → slower cooling
Model setup	Doublet configuration	Multi-fracture DFN	Mono-well & doublet

4. Conclusion

The numerical modeling of thermal energy storage in subsurface geothermal reservoirs presented in this study underscores the critical role of operational parameters in optimizing energy retention and retrieval. By investigating a range of conditions, including varying injection temperatures, flow rates, and permeabilities, this study demonstrates that geothermal reservoirs can be harnessed for long-term, sustainable thermal energy storage. Higher permeability is shown to be a key factor in enhancing recovery efficiency, with significant improvements in energy storage capacity. The results also highlight the importance of well configuration, particularly the spacing between injection and production wells, which plays a vital role in delaying thermal breakthrough and maintaining stable temperatures over extended cycles.

The coupling of thermal, hydraulic, and mechanical processes in fractured geothermal reservoirs provides a more accurate representation of real-world conditions compared to traditional models. The findings suggest that adjusting injection rates and temperatures, along with carefully selecting reservoir design parameters, can maximize recovery while ensuring the stability of the reservoir throughout multiple thermal cycles. Importantly, the minimal mechanical deformation observed in the study supports the viability of geothermal reservoirs as robust storage systems for both direct heating applications and electricity generation.

In conclusion, the study validates geothermal reservoirs as promising candidates for large-scale, long-duration energy storage systems. The insights gained from this research are crucial for advancing geothermal energy storage technologies, which can play a pivotal role in balancing energy supply and demand in renewable energy grids. Future research should continue to refine models that incorporate complex fracture network dynamics and geochemical interactions to further optimize geothermal storage systems and support their deployment at a global scale.

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