Coupling Geothermal Energy Capture with Carbon Dioxide Sequestration in Naturally Permeable, Porous Geologic Formations: A Comparison with Enhanced Geothermal Systems

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ABSTRACT

Geothermal energy offers clean, consistent, reliable electric power with no need for grid-scale energy storage, unlike wind and solar renewable power alternatives. However, geothermal energy is often underrepresented in renewable energy discussions and has considerable room for growth. New technology and methods will be critical for future investment, and rapid implementation of new techniques will be critical in ensuring geothermal energy plays a significant role in the future energy landscape worldwide. Here, we discuss a novel approach with the potential to permit expansion of geothermal energy utilization while supporting rapid implementation through the use of existing technologies: geothermal heat use in naturally porous, permeable geologic formations with carbon dioxide as the working heat exchange fluid.

Introduction

Carbon dioxide (CO_2) sequestration in deep saline aquifers and (partially exhausted) oil and natural gas fields has been widely considered as a means for reducing CO_2 emissions to the atmosphere as a counter-measure to global warming (IPCC, 2007). However, rather than treating CO_2 merely as a waste fluid in need of permanent disposal, we propose that it could also be used as a working fluid in geothermal energy capture.

CO_2 has been previously proposed as a geothermal working fluid, however, apparently only in the context of engineered geothermal systems (EGS) (e.g., Brown, 2000; Fouillac et. al., 2004; Pruess, 2006, 2007, 2008; Atrens et. al., 2009). EGS are typically generated by hydrofracturing rock of low natural permeability, which may induce seismicity. Hence, in addition to technical challenges, EGS must overcome significant socio-political resistance – as exemplified by the termination of EGS projects during the year 2009 (e.g., Basel in Switzerland; Glanz, 2009) – before widespread implementation can occur. In contrast, the method described here does not rely on hydrofracturing or similar permeability-enhancing technologies, thus avoiding several of EGS' challenges. Rather, it utilizes existing, high-permeability and high-porosity geologic reservoirs that are overlain by a low-permeability caprock. The sizes of such natural reservoirs are typically much larger than those of hydrofractured reservoirs. Consequently, the CO_2 sequestration potential of the system described here, where a large CO_2 plume displaces native fluids as in standard CO_2 sequestration approaches, is expected to be significantly larger than that of EGS.

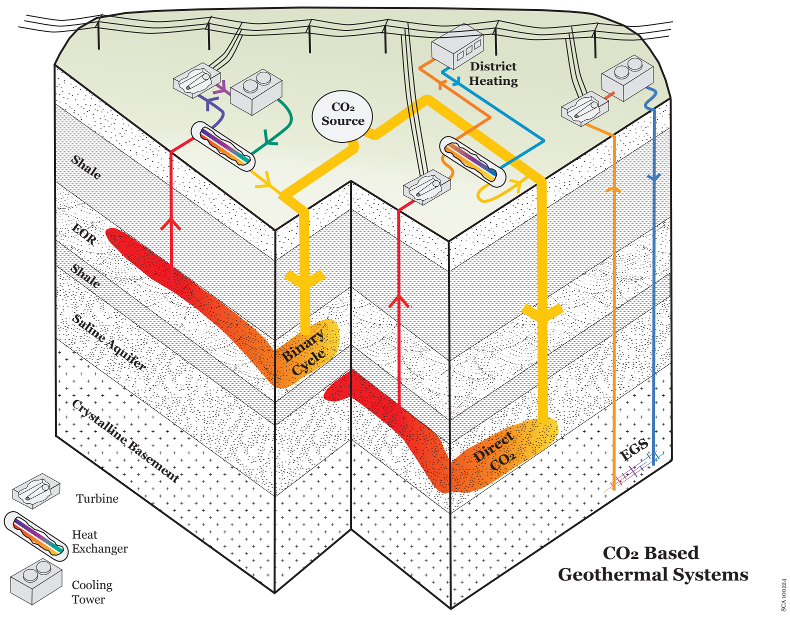

Figure 1. Several envisioned implementations of CO_2-based geothermal systems, including CO_2 plume geothermal (CPG) reservoirs established in deep saline aquifers or as components of enhanced oil recovery (EOR) operations. As in traditional geothermal approaches, energy recovered from CO_2-based geothermal systems could be used both for power production and for space/ water heating.

Therefore, we distinguish this approach from EGS and refer to it as a CO_2 plume geothermal (CPG) system.

The CPG technique involves pumping CO_2 into deep, naturally porous and permeable geologic formations where the CO_2 displaces native formation fluid and is heated by the natural in-situ heat and background geothermal heat flux (Figure 1). A portion of the heated CO_2 is piped to the surface and either sent through an expansion device, powering a generator and producing electricity, or sent through a heat exchanger to heat a secondary working fluid in a binary power system or to provide energy for district heating, before being returned to the subsurface. The injected CO_2 is permanently stored via geologic sequestration.

CO_2 is of interest as a geothermal working fluid because, among numerous other benefits, its thermodynamic and fluid mechanical properties suggest it transfers heat from the subsurface more efficiently than water (Pruess, 2006). In particular, under the geologic conditions relevant for CPG or CO_2-based EGS, CO_2 mobility is higher than that of water. Mobility, fluid density divided by dynamic viscosity (the inverse of kinematic viscosity), describes a fluid's tendency to preserve momentum while flowing. Higher mobility implies greater geologic fluid flow, resulting in improved geothermal heat extraction. Therefore, using CO_2 as the working fluid in geothermal power systems may permit utilization of geologic formations that are deemed economically unviable with current water-based technology.

Numerical simulations indicate at present that CPG systems provide significantly improved heat energy recovery over similar water-based systems. The purpose of the present investigation, however, is to compare CPG and EGS with CO_2. While EGS with CO_2 is a recent development in geothermal technology, the existing preliminary research on the method provides context to determine the feasibility of the very new CPG approach presented here. We focus here on the permeabilities and hydraulic characteristics of CPG and CO_2-based EGS reservoirs and the consequential differences in geothermal heat energy extraction.

Permeability Comparison

General System Parameters: Several geothermal reservoir and fluid injection/production characteristics are important in an early-stage comparison of CPG and CO_2-based EGS heat energy extraction, the most critical being reservoir permeability, temperature, pressure, size, and fluid injection/production rate. In a numerical exercise, we have the luxury of adjusting these parameters as desired within the limits of what may be encountered in natural systems.

For the purpose of investigating CO_2 geothermal potential in low-to-moderate geothermal heat flow regions (as comprise most of the Earth's surface; Blackwell and Richards, 2004), reservoir (initial) temperature and pressure of 100ºC and 250 bar (2.5km deep formation), respectively, are employed. While these values suggest a shallower and lower temperature field than typically targeted for EGS (e.g., Soultz, France; Evans et. al., 2005), such a site may be envisioned. Furthermore, such values may be encountered at several potential geologic CO_2 sequestration sites, including the Williston Basin of North Dakota and the Alberta Basin (Steadman et. al., 2006), which may be of interest as targets for CPG installations.

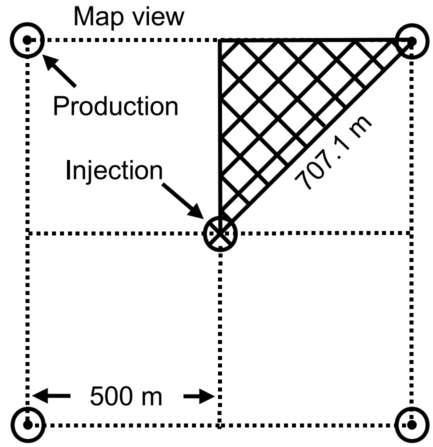

Figure 2. Five-spot well configuration for reservoir simulation. By symmetry, only the gridded section of the domain need be modeled.

A five-spot well configuration (Figure 2) is utilized to facilitate comparison of numerical modeling results with existing CO_2-based EGS studies (Pruess, 2006, 2008). To ensure models for the present study function correctly, the models and results of Pruess (2006) were first reproduced (not shown). The symmetry of the five-spot computational grid reduces modeling requirements to $1/8^{th}$ of the system domain. The two-dimensional grid consists of 36 primary grid blocks, each with 70.71m side length. For CPG simulations, blocks consist of a continuous porous medium matrix with a porosity of 20%, consistent with several CO_2 sequestration basins including the Williston and Alberta Basins (Steadman et. al., 2006). EGS simulation reservoirs contain two orthogonal fracture sets imbedded in a matrix of negligible permeability, with a resulting system porosity of 2%. Fractures accommodate fluid flow while the matrix provides thermal energy storage; fracture/matrix heat exchange is accomplished via the multiple interacting continua (MINC) method (Pruess and Narasimhan, 1985).

Fluid injection and production rates are determined by specifying a 20 bar pressure difference between wells (bottom hole). Heat extraction rate (H) and fluid flow rate (Q) are monitored at a production well, with the former defined as $H = Q(h - h_o)$, where h is the enthalpy of the produced fluid and h_o is the enthalpy of the fluid at injection conditions (T = 20ºC). The system is assumed

Table 1. TOUGH2 simulation parameters. Those defined as "variable" are described in detail in the text.

Reservoir Formation		Injection and Production Conditions	
Thickness	305 meters	Reservoir mapview area	1 km^2
Well separation	707.1 meters	Temperature of injected fluid	20 ºC
Permeability	(variable)	Injection/production rate	max. 300 kg/s (variable)
Porosity (CPG)	20% (0.20)	Downhole injection pressure	260 bar
Rock grain density	2650 kg/m^3	Downhole production pressure	240 bar
Rock specific heat	1000 J/kg/ºC	Injection/production duration	25 years
Thermal conductivity	2.1 W/m/ºC		
Initial conditions		**Boundary conditions**	
Reservoir fluid	All CO_2	Top and sides	No fluid or heat flow
Temperature	100 ºC	Bottom	No fluid flow, heat conduction
Pressure	250 bar		

to contain CO_2 only; while the displacement of native formation brine or other fluid by CO_2 is important, it is not the focus of the current study. Rock characteristics loosely mirror those of the Soultz EGS site (Pruess, 2006) and represent average values that may typically be encountered in EGS or CPG implementations. All simulations are completed utilizing the well-established reservoir simulator TOUGH2 (Pruess, 2004) with the fluid property module ECO2N (Pruess, 2005). Table 1 provides a full list of model parameters and conditions.

Permeability: The remaining critical parameter to be defined for these simplified simulations is permeability. For CPG cases, the choice is straightforward – we select a value of $5x10^{-14}m^2$, consistent with that measured at several CO_2 sequestration sites. Fields in the Illinois Basin report values ranging from $3.0x10^{-14}$ to $10x10^{-14}m^2$ (Finley, 2005), whereas the saline aquifer systems of Alberta, Saskatchewan, North and South Dakota, and Montana have values ranging from $9.3x10^{-15}$ to $9.3x10^{-12}m^2$ (Steadman et. al., 2006).

Permeabilities for CO_2-based EGS simulations are less readily defined. Approach 1: EGS model permeability could be selected to be the same as that of a CPG model, which is useful for a comparison of thermal energy extraction between the two reservoir systems without the need to consider complications of hydraulic effects. Such an EGS permeability, however, is not necessarily representative of values found at actual EGS implementation sites. Approach 2: Thus, we also model EGS fracture permeability consistent with hydraulically stimulated basement rock.

Concerning Approach 2, the limited number of production-scale (water-based) EGS facilities hinders selection of a representative reservoir-scale permeability for CO_2-based EGS simulations. The Soultz, France, EGS site provides a post-stimulation, reservoir-scale value of $6x10^{-14}m^2$ (Evans et. al., 2005). To provide at least one additional value, we employ an analytical approach to approximate reservoir-scale permeability of a hydraulically-stimulated basement rock reservoir from core-scale, pre-stimulated basement rock samples.

Analytic Permeability Calculation: Intact core samples from the Soultz site have permeabilities that range from 10^{-18} to $10^{-16}m^2$ (Shapiro, 1999; Evans, 2005). Of interest for future geothermal work in the interior North American continent, core samples from the Midcontinental Rift System at depths greater than 3500m have an average permeability of $10^{-18}m^2$ (Thorleifson, 2008). Choosing a pre-hydraulic-stimulation value of $10^{-17}m^2$ and assuming stimulation increases permeability by approximately a factor of 200, as was the case at Soultz (Evans, 2005), post-stimulation core-scale EGS permeability would be $2x10^{-15}m^2$.

To upscale core permeability (i.e., the permeability of an individual fracture) to bulk reservoir permeability, we apply electrical resistor theory to the five-spot EGS grid (with fracture spacing set to 70.71 m). Ohm's law, $I = \Delta V/R$, where I is current, ΔV is voltage difference, and R is electrical resistance, is analogous to Darcy's law, $q = -K\nabla h$, where q is Darcy velocity, ∇h is hydraulic head gradient, and $K = \rho gk/\mu$ is hydraulic conductivity with ρ denoting fluid density, g Earth's gravitational acceleration, k permeability, and μ dynamic fluid viscosity (Fatt, 1956). Assuming fluid density and dynamic viscosity are constant, R is analogous to permeability, k. Thus, we may apply Kirchoff's first rule – which states that the sum of currents entering a node must equal the sum of currents exiting a node in an electrical circuit – to a fracture network.

In the MINC approach, fractures effectively exist along the boundaries of primary grid blocks; however, fractures *connect* between adjacent grid blocks (Pruess and Narasimhan, 1985). Fracture connections, not fracture positions, are the important aspect in reservoir fluid flow and, hence, the analytic permeability calculation. Thus, the fracture network in Figure 3 comprises the permeable domain of the five-spot EGS model. Notice that the injection and production wells (i.e., nodes) have been connected by a non-resistive "wire," which closes the fracture circuit as required by Kirchoff's law. A "current" (i.e., fluid flow) of 1 amp is applied to the circuit to establish a "voltage" (i.e., hydraulic head) gradient across each fracture, and the injection well is grounded, to permit calculation of reservoir permeability.

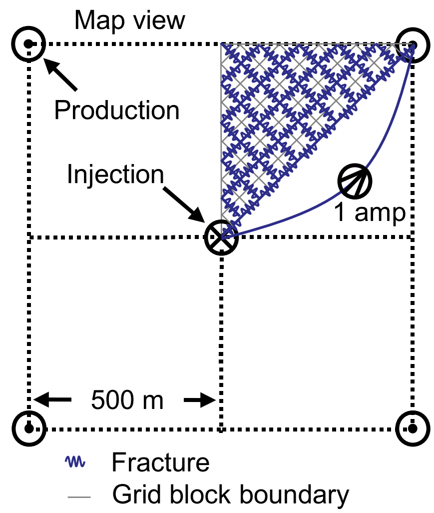

Figure 3. Network of connected fractures that comprise the permeable domain of EGS models in this study, here modified in order to complete the flow "circuit," permitting an analytical calculation of reservoir-scale permeability.

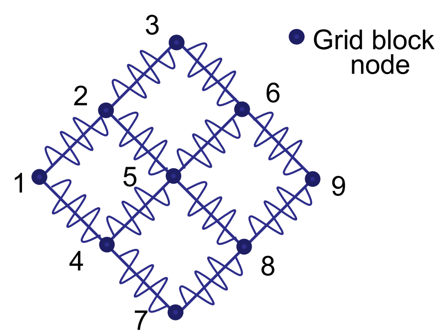

Figure 4. Expanded view of a section of the fracture network from Figure 3.

Consider Figure 4, a section of the fracture network from Figure 3. Applying Kirchoff's law to node 5 of the fracture network gives the equation $(V_2-V_5)/R + (V_4-V_5)/R + (V_6-V_5)/R + (V_8-V_5)/R = 0$, where V_i is the "voltage" (i.e., hydraulic head) at node i and R is the "resistance" (i.e., permeability) of an individual fracture. Applying Kirchoff's law to each node in the fracture network except the injection well (for which we know the "voltage" = 0) provides a system of 35 linear equations with 35 unknown voltages. Solving the system of linear equations, then solving Ohm's law with $I = 1$ amp and ΔV = (voltage difference between production and injection wells), the effective "resistance" (i.e., permeability) of the fracture network can be determined for a given individual fracture permeability. We find that the bulk system permeability is a factor of 5.4 that of the permeability of an individual fracture.

Returning to the chosen core-scale EGS permeability of $2x10^{-15}m^2$, the effective system-scale permeability is then $1.1x10^{-14}m^2$. For the purpose of this numerical exercise, we average this value and measured EGS permeability from Soultz, resulting in a fracture system permeability of $3.5x10^{-14}m^2$, which is used in Approach 2 to compare CPG and CO_2-based EGS. While more permeability values from EGS implementations would be preferred, the preceding technique provides one method for comparing CO_2-based geothermal systems.

Energy Recovery from CO_2 Geothermal

Results of simulations corresponding to Approach 1, in which CPG and CO_2-based EGS reservoirs have the same system permeability of $5x10^{-14}m^2$, are shown in Figure 5. Three EGS cases are considered, corresponding to fracture spacings of 70.71m (chosen equal to the primary grid block side length), 141.42m (i.e., 2 x 70.71m), and 212.13m (i.e., 3 x 70.71m). Figure 5 displays temperatures along a line from injection to production well after 10 simulated years of CO_2 injection and production from the reservoir. Notice that the temperature at the production well in the CPG case is closer to the initial reservoir temperature (100ºC) than in any of the EGS cases, with EGS production well temperature decreasing with increasing fracture spacing. This result indicates more widespread heat mining in the CPG system than the EGS cases, a consequence of the CO_2 being in contact with more reservoir rock or sediment in CPG.

Time series of geothermal heat extraction for CPG and EGS cases are provided in Figure 6. All rates are given on a full-well basis (i.e., for the entire five-spot system). For a given case, heat extraction rates decrease with time as the reservoir system heat is depleted and the temperature at production wells decrease. Mass flow rates remain relatively constant with time. The CPG system provides more widespread heat mining than the EGS cases, thus maintaining higher temperatures at the production well for longer duration. Produced fluid temperature decreases with time more rapidly as EGS fracture spacing increases, a consequence of less reservoir material being in contact with heat exchange fluid.

In the EGS simulation corresponding to Approach 2, with system permeability of $3.5x10^{-14}m^2$, heat energy extraction is considerably lower than in the CPG system and EGS with similar fracture spacing. Lower permeability results in smaller fluid mass flow rates, producing lower heat energy extraction rates.

Concluding Remarks

While additional research is required, numerical modeling results at present suggest that geologic reservoirs with CO_2 as the heat mining fluid would be viable geothermal energy sources for power production for decades, potentially even in regions with relatively low geothermal temperatures and heat flow rates. Early-stage studies by several authors have suggested the potential of enhanced geothermal systems (EGS) with CO_2 as the geothermal working fluid (e.g., Pruess, 2006; Atrens et. al., 2009). The work presented here, however, demonstrates that in certain situations, CO_2 plume geothermal (CPG) systems provide better geothermal heat energy recovery than EGS with CO_2.

The primary consideration of the current study is a comparison of CPG and CO_2-based EGS heat energy extraction, with a focus on reservoir system permeability. Additional work will contrast CPG systems with water-based conventional geothermal and EGS as well as examine the process of CO_2 plume formation and reservoir native fluid displacement.

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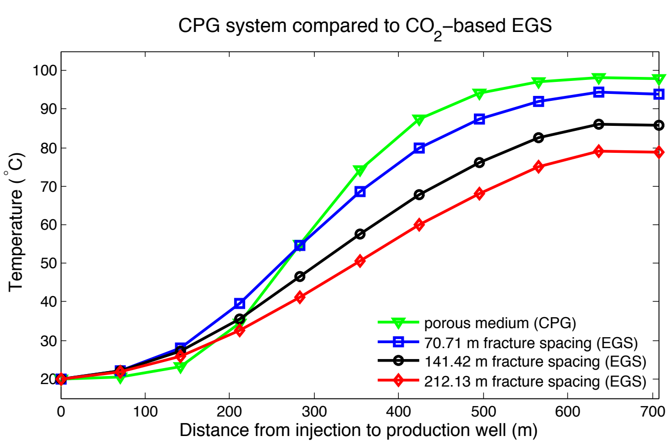

Figure 5. Temperature profiles along a line from injection to production well after 10 simulated years of injection and production; system permeability in all cases is $5x10^{-14}m^2$. The higher CPG than EGS temperature at the production well indicates more widespread heat mining in the CPG case.

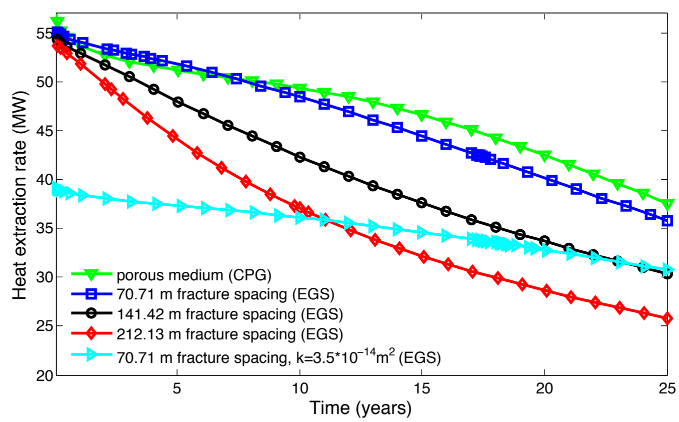

Figure 6. Time series of simulated geothermal heat energy extraction. Heat extraction rate is defined as the enthalpy difference between injected and produced fluid multiplied by the rate of fluid production. Unless otherwise noted, system permeability is $5x10^{-14}m^2$. The CPG system maintains higher production temperatures for longer time than EGS with the same permeability, resulting in higher heat energy extraction rates.

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