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Total Heat Energy Output From, Thermal Energy Contributions To, and Reservoir Development of CO_2 Plume Geothermal (CPG) Systems.

Nagasree Garapati[1], Jimmy B. Randolph[1,2], and Martin O. Saar[1.2]

[1.] Department of Earth Sciences, University of Minnesota, Minneapolis, MN; [2.] Heat Mining Company LLC, Rapid City, SD

saar@umn.edu

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ABSTRACT

CO_2-Plume Geothermal (CPG) energy capture involves injecting CO_2 into naturally-permeable sedimentary basins to serve as the working fluid for geothermal energy extraction. The injected CO_2 forms a large subsurface CO_2 plume that extracts heat energy from the reservoir, whereafter the CO_2 is produced to the surface to drive a power system, is cooled and reinjected into the subsurface. While the heat density of sedimentary basins is typically relatively low, the large volume of such natural reservoirs accessible using CO_2, compared to conventional and hydrofractured reservoirs, may counteract this limitation and in some cases surpass the total heat energy output possible from the latter. Here, we analyze the volume of CO_2 that is required to form a CPG system as a function of the desired longevity of geothermal heat extraction, the reservoir temperature and depth, and the desired power production rate. In addition, we analyze the contribution of the reservoir rock/sediments, the native reservoir fluids, the over- and underlying low-permeability capping units, and the geothermal heat flux to the total extracted geothermal heat energy. To conclude, we show that, depending on system configuration and operation, a CPG system can operate for several decades with little decrease in produced fluid temperature.

1 INTRODUCTION

Carbon dioxide (CO_2) capture and sequestration (CCS) in deep saline aquifers has been widely considered as a means for reducing CO_2 emissions into the atmosphere. Numerous previous studies (Brown, 2000 , 2003; Fouillac *et al.*, 2004; Pruess, 2006, 2007, 2008; Atrens *et al.*, 2008) have discussed utilizing CO_2 as a geothermal working fluid, however, only in the context of enhanced geothermal energy systems (EGS). EGS typically involve hydraulic fracturing of rock that naturally has low permeability, a process that typically induces seismicity (Evans *et al.*, 2005; Majer *et al.*, 2007). In contrast, CO_2 Plume Geothermal (CPG) energy systems (Randolph and Saar, 2010, 2011a, 2011b, Saar et al., 2012; Buscheck et al., 2013) involve injection of CO_2, that comes from a CO_2 emitter such as a coal-fired-power plant, ethanol plant, or cement manufacturer, as a working fluid to extract heat from naturally high-permeability geologic units that lie below low-permeability caprocks illustrated in Figure 1. The injected CO_2 forms a large subsurface CO_2 plume that permanently sequesters CO_2 underground but also absorbs heat from the geothermal reservoir and can thus be "tapped" to generate power in a closed-loop power system as described in Randolph and Saar (2011a) and Saar et al. (2012). Therefore, CPG systems exhibit significantly different heat extraction and power generation performance characteristics and can be added to full-scale geologic CO_2 sequestration operations, compared to EGS (Randolph and Saar, 2010, 2011a, 2011b). After the CO_2 is produced to the surface to drive a power generation system, the CO_2 is cooled and reinjected, into the geothermal and CO_2 storage reservoir along with the main CO_2 stream that comes from the CO_2 emitter. While the heat density of sedimentary basins is typically relatively low, the large accessible volume of such natural reservoirs, compared to artificially hydrofractured EGS, and thus smaller-scale reservoirs, may counteract this limitation and in some cases likely surpass the total heat energy output possible from the latter. Furthermore, supercritical CO_2 has a large mobility (inverse kinematic viscosity) and thermal expansibility compared to water, resulting in the formation of a strong thermosiphon (Adams et al., 2014) that typically eliminates parasitic pumping requirements. Both effects significantly increase electricity production efficiency. Because the produced CO_2 is reinjected into the deep saline aquifers along with the main CO_2 sequestration stream coming from a CO_2 emitter, CPG systems can be operated as CO_2 sequestering geothermal power plants that have a significant negative carbon footprint, compared to EGS where the amount of permanently sequestered CO_2 would be comparatively small or negligible (Dezayes *et al.*, 2005). Alternatively, when geologic CO_2 storage is uneconomic, CPG could also be operated with a limited, finite amount of CO_2 stored underground and thereafter run with little or no additional makeup CO_2 if desired. The lifespan of the geothermal power plant can be increased by operating the CPG system such that it depletes the geothermal reservoir heat slowly.

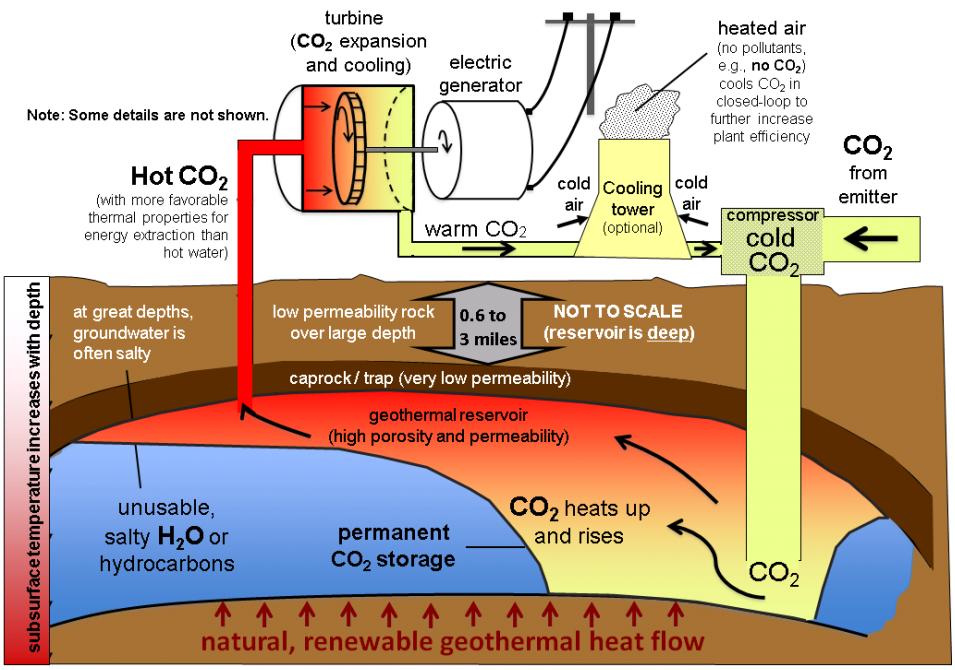

Figure 1. Simplified schematic of one possible implementation of a CPG system, established in a deep saline aquifer.

In this paper, we consider the situation described above, when CO_2 storage is uneconomic, for example due to limited CO_2 supply when CO_2 emitters are located far away or when CO_2 is expensive. In such cases, the amount of CO_2 required to operate a CPG system should be minimized. As a guide to determine if a CO_2 plume sufficiently large for CPG operations has been established, we require at least 94% CO_2 concentration in the produced fluid, as this appears to be necessary for safe and efficient operation of some CO_2-based power generation turbines (Welch and Boyle, 2009) in direct CPG systems. Alternatively, an indirect, i.e., binary power system could be installed, such as an Organic Rankine Cycle, however, such systems suffer from efficiency loss compared to direct systems and are thus less desirable. Therefore, we calculate the minimum, finite amount of CO_2 that is required in the geothermal reservoir to ensure at least 94% CO_2 is present in the produced fluid as a function of the reservoir size, depth, and temperature. Additionally, we investigate the longevity of geothermal heat extraction through analysis of the contribution of the reservoir rock/sediments, the over- and underlying low permeable cap rocks, and the native reservoir fluids to the extracted heat. Combined, these two metrics, 1) finite amount of CO_2 required for continuous CPG operation with at least 94% CO_2 present in the production fluid and 2) longevity of the geothermal reservoir, provide an estimate of the practicality of establishing and operating a CO_2-Plume Geothermal (CPG) system with a limited amount of CO_2 under some basic geologic and CO_2-supply conditions.

2 NUMERICAL MODEL

The current model is radially symmetric and, thus, a cylindrical coordinate system is employed (Figure 2). In keeping with the objective of formulating a simple model to gain first-order insights, we assume a homogeneous reservoir with symmetrical CO_2 plume formation around the injection well. In actual systems, the CO_2 plume would likely be skewed due to an underlying groundwater flow direction or a sloped reservoir/caprock interface. In such cases, a half-circular, parabolic, or simply straight horizontal production well would likely be installed directly underneath the caprock to capture the CO_2 in the reservoir. However, as results of the amount of CO_2 required in the reservoir and of heat extracted from the reservoir are likely at most minimally affected by whether the CO_2 is symmetrically distributed around the injection well or skewed, we employ a three-dimensional but axisymmetric system that allows significant reductions in computational effort (Figure 2). The primary-case geothermal reservoir is located at an average depth of 2.5 km and has a thickness of 50 m and a porosity of 0.10. Initially, the reservoir is assumed to be filled with native brine with a NaCl saturation of 20% mass fraction; during simulation, the brine is gradually displaced by injected supercritical CO_2 from a vertical, linear injection well and is produced from a horizontal, circular production well that is located directly below the caprock (Figure 2).

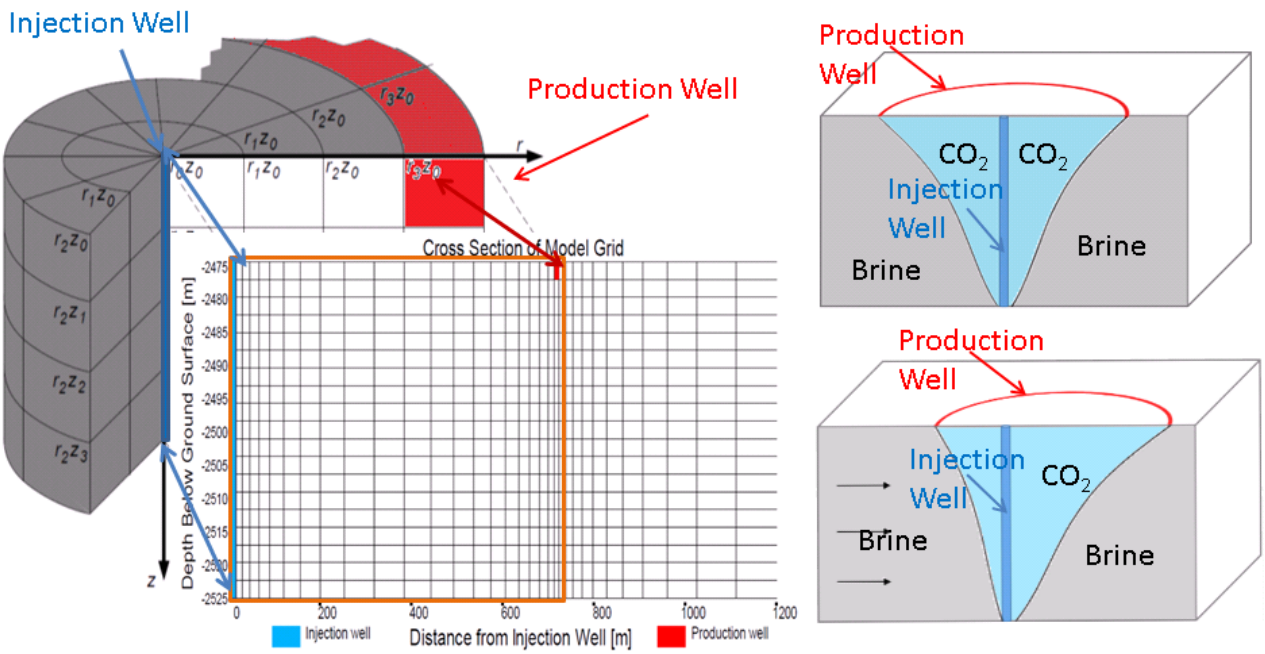

Figure 2. Three-dimensional (3D), axisymmetric model with a cross section of the geothermal reservoir showing grid discretization and well placement. The caprock bottom is located at a depth of 2475 m. The injection well is vertical and fully penetrating within the reservoir and constitutes the axis of symmetry. The production well is horizontal, circular and located just below the caprock at various distances from the injection well (here shown are 707 m). The model extends horizontally to 100 km to minimize boundary effects, with logarithmically increasing horizontal grid spacing away from the injection well but horizontal refinement of grid spacing near the production well. The block diagrams to the right show symmetric (top) and asymmetric (bottom) CO_2 plume formation as described in the main text.

The numerical simulator employed is the well-established and tested simulator TOUGH2 (Pruess *et al.*, 1999; Pruess, 2004) with the equation of state (EOS) module ECO2N (Pruess, 2005) and, for higher temperatures, ECO2H (Spycher and Pruess, 2011). In all simulations, brine displacement by CO_2 is simulated and CO_2 is permitted to dissolve into the brine, as well as water into the CO_2. As dissolution occurs only at the brine-CO_2 interface, such dissolution minimally affects CO_2 circulation on the timescale considered in the present analyses. Table 1 lists additional details about the model setup, including the use of a standard semi-analytic conductive heat exchange boundary condition to over- and underlying layers (Pruess *et al.*, 1999), employed in some simulations, along with numerical model parameters. In base-case simulations, the CO_2 plume is built over 2.5 years with 2 Mtons of CO_2 injected, at a rate increasing linearly from 0 to 1 Mton/year over the first year, and then at a constant rate of 1 Mton/yr for an additional 1.5 yrs (Figure 3). Once the CO_2 plume is built, new CO_2 injection is stopped (in base-case simulations) and fluid (mostly CO_2) production and circulation is initiated. The circulation rate is increased linearly over 2 years, and then maintained at a constant rate for an additional 98 years.

Table 1. Numerical model parameters for base case.

Model Parameter/Condition	Value
Number of grid cells, vertical	20
Numerical grid configuration	Radially symmetric about the injection well
Well spacing, [m]	707
Well orientation	Vertical (injection), horizontal circular (production)
Boundary conditions (top/bottom)	No fluid flow, semi-analytic heat exchange
Boundary conditions (lateral)	No fluid or heat flow
Initial conditions	Hydrostatic equilibrium, no heat flow, all pore space occupied by brine

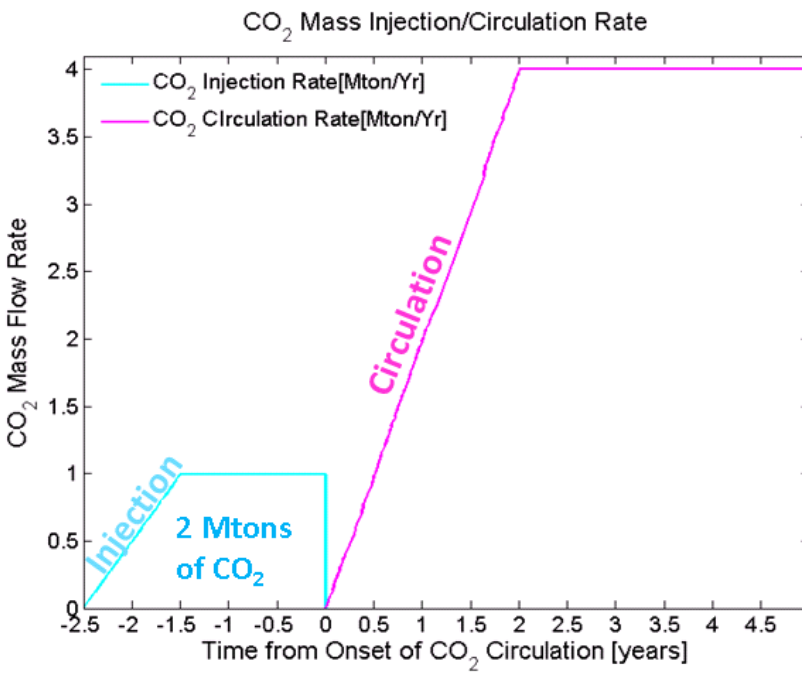

Figure 3. CO_2 mass flow rate during initial CO_2 plume formation period (cyan line) and during fluid (mostly CO_2) production and circulation (pink line) for base case simulations. CO_2 plume formation occurs at times before 0 years. CO_2 production and circulation starts at time t =0 years. Injection and circulation rates are varied in some simulations.

A base case reservoir model is developed with the geologic conditions provided in Table 2, and the reservoir fluid parameters listed in Table 3. Randolph and Saar (2011a) provide further explanations for the choice of specific reservoir parameters.

Table 2. Reservoir physical parameters for the base case.

Reservoir Parameter/Condition	Value
Average depth, D [m]	2500
Horizontal permeability, k_x [m^2]	5×10^{-14}
Vertical permeability, k_z [m^2]	2.5×10^{-14}
Thermal conductivity [W/m/^{0}C]	2.10
Thickness [m]	50
Temperature, T [^{0}C]	100
Porosity	0.10
Rock specific heat [J/kg/^{0}C]	1000
Rock grain density [kg/m^3]	2650
Radius [m]	100,000
Geothermal gradient[^{0}C/km]	34

Table 3. Reservoir fluid parameters.

Fluid Property	Value
Residual brine saturation fraction	0.30
van Genuchten, m	0.457
Native brine NaCl saturation [ppm]	200,000
Residual CO_2 saturation	0.05
van Genuchten, a [1/Pa]	$5.1\text{x}10^{-5}$

In addition to the base case, various additional cases are considered in order to analyze the amount of CO_2 that is required for functioning CPG systems, as defined below. Parameters that are varied are: reservoir size (thickness, well spacing), geologic parameters (reservoir depth, geothermal gradient), and CO_2 circulation rate. The following simulations are considered: 1) different

injection and circulation rate patterns, 2) reservoir thickness is increased to 100 m; 3) distance between injection and production wells is changed from 707 m to 500 m and to 1000 m; 4) formation depth is varied from 2.5 km to 1.5 km and to 3.5 km; and 5) geothermal gradient is changed from 20^{0}C /km, to 35^{0}C /km and to 50^{0}C /km. In all simulations, except for the varying parameter, all other parameters are kept the same as in the base case. The amount of CO_2 required during the initial plume formation period is calculated based on the CO_2 concentration in the produced fluid to avoid power system problems as discussed by Welch and Boyle (2009) who found that CO_2 concentration should be >94% in the systems they investigated.

Heat contributions are calculated for the base case. Heat from the over- and underlying cap rock units is calculated as the amount of heat gained by the reservoir by semi-analytic conductive heat exchange at the boundaries (Pruess *et al.*, 1999). The amount of heat from the reservoir rock and native fluids is calculated from the mass and heat balances of the system at each time step. The heat contribution from geothermal heat flux and conduction from bounding units is calculated as the difference between the heat extracted from the reservoir with and without heat exchange at the boundaries. We also study heat extraction and temperature depletion rates for varying CO_2 circulation rates.

3 RESULTS AND DISCUSSION

In all figures, time is set to zero at the start of fluid (mostly CO_2) production and circulation. We first discuss the minimum amount of CO_2 required in the reservoir for continuous CPG operation without further CO_2 injection (Section 3.1). Then heat extraction rates and heat contributions are discussed in Section 3.2.

3.1 Amount of CO_2 required

We find that up-coning of brine at the production well can be reduced by changing CO_2 injection and circulation rate patterns as shown for the second case in Figure 4. In the first, base case, once the CO_2 plume is built, new CO_2 injection is halted and fluid production and circulation is initiated (red line in Figure 4). In the second case (blue line in Figure 4), instead of stopping CO_2 injection before initiating produced fluid circulation, the CO_2 injection rate is gradually reduced while the produced fluid circulation rate is increased. CO_2 injection is stopped once the produced fluid circulation has reached its maximum value. Figure 5 shows that there is only insignificant up-coning of brine into the produced fluid in the second case, however, a larger total amount of CO_2 is required for CPG operation when up-coning is reduced by continuing CO_2 injection into the production phase (inset of Figure 4). Hence, in keeping with our objective of determining the minimum amount of CO_2 required for CPG operation, we consider hereafter only the first case, where CO_2 injection is halted before fluid production and circulation commences, while still ensuring approximately >94% CO_2 in the production fluid.

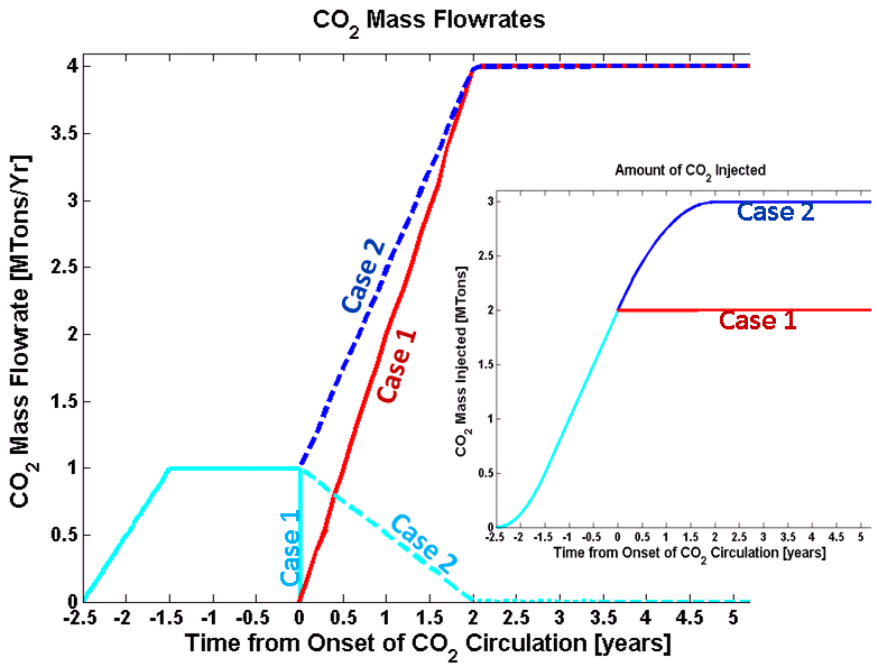

Figure 4. CO_2 flow rates during the injection and production periods with time and total amount of CO_2 injected. CO_2 plume formation occurs during times before 0 years. Fluid (mostly CO_2) production and circulation starts at time t =0 years.

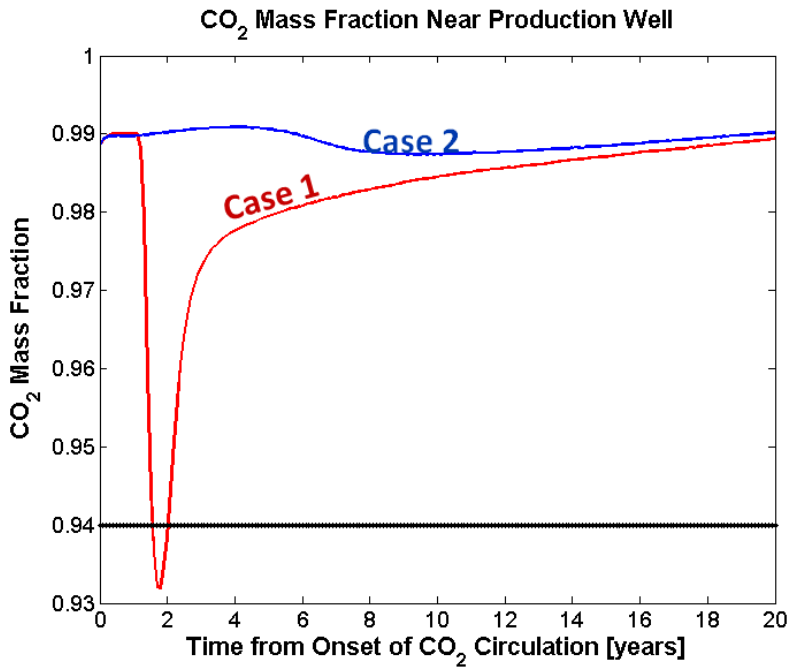

Figure 5. Produced CO_2 mass fraction versus time with injection stopped before fluid production and circulation (Case 1: red, base case, used hereafter) begins and for a slowly decreasing injection rate (Figure 3) that continues into the fluid production phase (Case 2: blue). The minimum amount of CO_2 saturation in the produced and circulated fluid should not fall significantly below 94% as discussed in the main text.

3.1.1 Effective Reservoir Size

The effective reservoir size can be modified by either considering a thicker reservoir or by changing the distance between the injection and production wells. The amount of CO_2 required for sufficient plume formation to produce the fluid with at least 94% CO_2 concentration increases with the effective reservoir size. First, we consider an increase in reservoir thickness from 50 m to 100 m as well as varying the amount of CO_2 injected initially for CO_2 plume formation before CO_2 production commences. Figure 6 shows the mass fraction of CO_2 in the produced fluid with time.

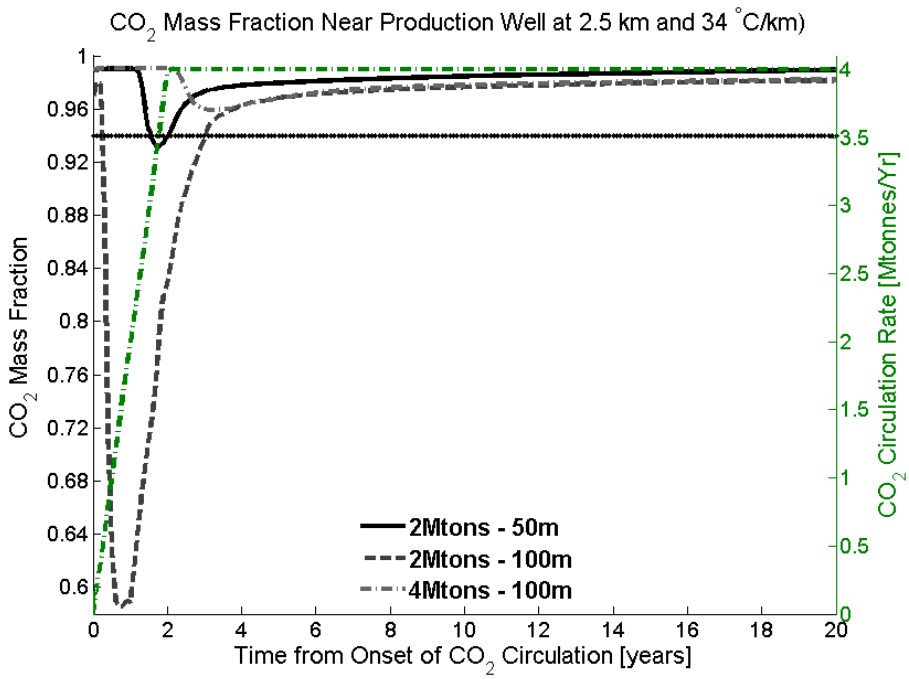

Figure 6. Produced CO_2 mass fraction versus time for two reservoir thicknesses (50 m and 100 m) and total amount of CO_2 injected for initial CO_2 plume formation (2 Mtons and 4 Mtons). The produced fluid (mostly CO_2) circulation rate through the system is shown by the dashed-green line on the secondary axis. The minimum amount of CO_2 saturation in the produced and circulated fluid should not fall significantly below 94% as discussed in the main text.

Figure 6 shows that for a 50 m thick reservoir, 2 Mtons of total injected CO_2 is sufficient to produce CO_2-rich fluid (close to the desired minimum 94% CO_2 concentration) at all times of fluid circulation. As the reservoir thickness increases, the amount of required total injected CO_2 also increases, to 4 Mtons (at an injection rate increasing linearly from 0 to 2 Mtons/year over the first year and then at a constant rate of 2 Mtons/yr for an additional 1.5 yrs – not shown in Figure 6). Thus, doubling the reservoir thickness requires a doubling of the total amount of injected CO_2, resulting in similar minimum CO_2 concentrations for the 2 Mtons/50 m and 4 Mtons/100 m cases, while keeping the amount of total injected CO_2 at 2 Mtons for a 100 m thick reservoirs results in less than 60% CO_2 concentration in the produced and circulated fluid (Figure 6). As expected, the time at which the produced fluid has a minimum CO_2 concentration decreases with increasing reservoir thickness for the same amount of CO_2 injected and increases with the amount of CO_2 injected due to thick plume formation near the production well, which in turn increases the CO_2 concentration in the produced fluid as discussed above.

The effective volume of the reservoir also depends on the distance between the injection and production wells. During the initial plume formation period, the distance the CO_2 migrates from the injection well depends on the amount of CO_2 injected. The well spacing between the production and injection wells has to take this CO_2 migration distance into account to minimize up-coning of brine into the production well. Figure 7 shows the CO_2 saturation in the reservoir after 2.5 years of CO_2 injection for plume development, before fluid production and circulation commences.

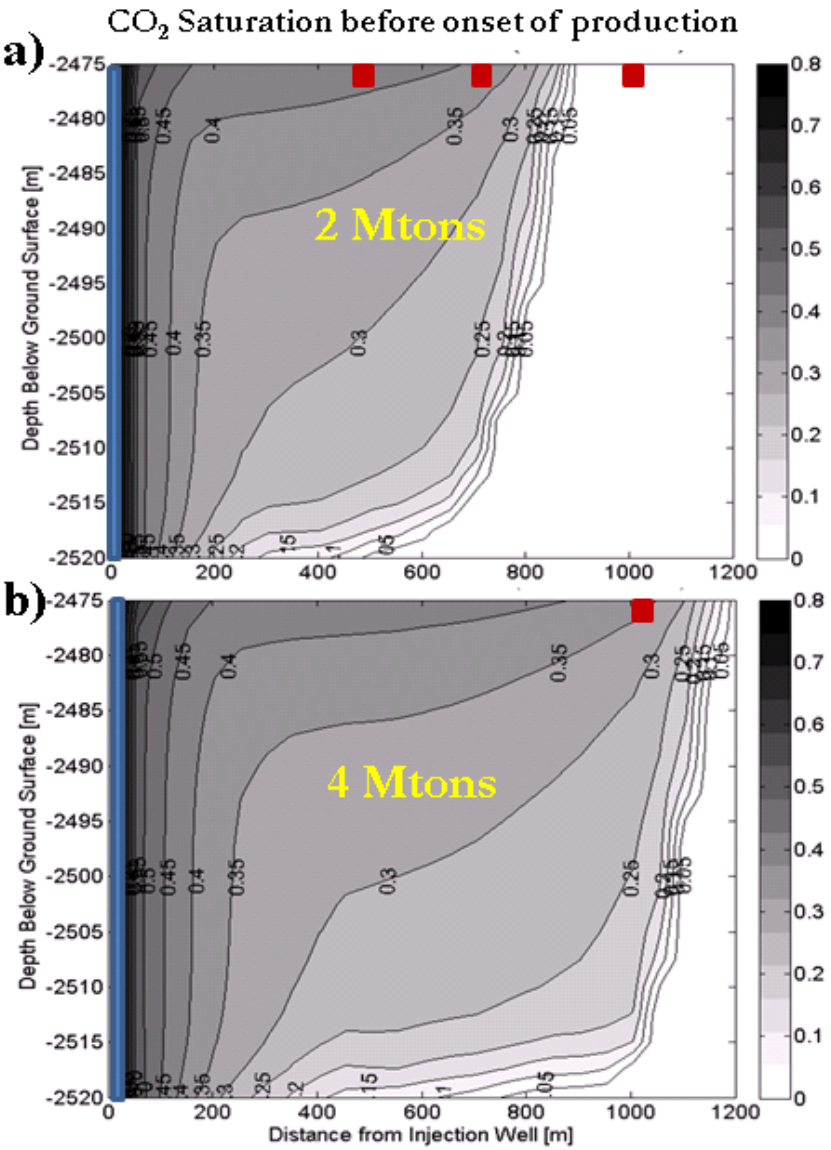

Figure 7. Contour plot of the CO_2 saturation in the geothermal reservoir pore fluid after initial CO_2 plume formation by injecting (a) 2 Mtons and (b) 4 Mtons of CO_2 in 2.5 years. Here and elsewhere, the blue, vertical line to the left marks the location of the vertical, within the reservoir fully penetrating, injection well, while the red squares at the top of the reservoir indicate possible locations of the horizontal, circular production wells as discussed in the main text.

When 2 Mtons of CO_2 are injected, the CO_2 migrates up to 800 m from the injection well at the top of the reservoir as shown in Figure 7a. When 4Mtons of CO_2 are injected, the CO_2 migrates beyond 1000 m from the injection well as seen in Figure 7b. While smaller amounts of CO_2 are desirable when only a limited amount of CO_2 is available, larger total amounts of injected CO_2 and corresponding greater distances between injection and production wells may be of interest when CO_2 availability is not as big of a concern and when longer geothermal reservoir operation times are of interest.

3.1.2 Reservoir Temperature and Depth

The performance of a CPG system depends on many factors; here, we focus on reservoir temperature and depth. The temperature of the reservoir is a function of both depth and the geothermal gradient of the location. Simulations are conducted at various depths and geothermal gradients to calculate the amount of CO_2 required for successful operation of the CPG systems. The results of the simulations with different depths are presented in Figure 8. For this set of simulations reservoir pressure is calculated as hydrostatic pressure. Temperature of the reservoir is calculated with a geothermal gradient of 34^{0}C/km, the approximate continental average (Pollack *et al.*, 1993), and 15^{0}C mean annual surface temperature. The injection temperature is calculated based on isentropic compression for CO_2 in the injection well, and is given in Table 4. The solubility of water into the supercritical CO_2 increases with pressure and temperature. Therefore as depth increases, the CO_2 mass fraction in the produced fluid decreases for the same amount of CO_2 injected (2Mtons). As the injected volume increases the gas saturation near the production well increases and, hence, the CO_2 mass fraction increases as well (Figure 8).

Table 4. Pressure and temperature conditions at different depths.

Average depth, D [km]	Reservoir Pressure [bar]	Reservoir Temperature, T [^{0}C]	Injection Temperature, T_{ini} [^{0}C]
1.5	150	66	35
2.5	250	100	46
3.5	350	134	58

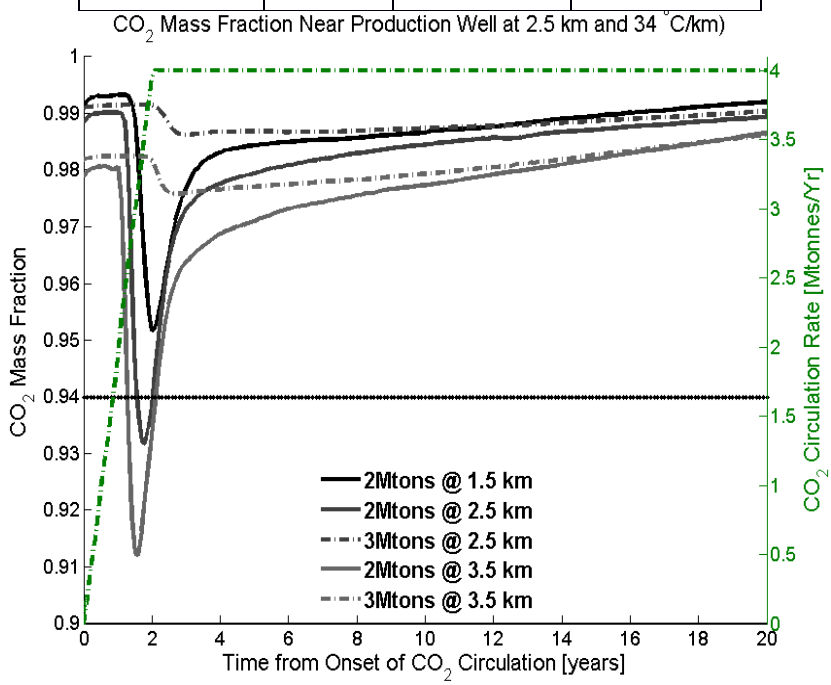

Figure 8. Produced CO_2 mass fraction versus time for various formation depths and amount of CO_2 injected for initial CO_2 plume formation. The CO_2 circulation rate through the system is shown by the dashed green line on the secondary axis.

Three different geothermal gradients, 20^{0}C/km, 34^{0}C/km, and 50^{0}C/km, are considered resulting in corresponding reservoir temperatures of 65^{0}C, 100^{0}C and 140^{0}C, respectively. The reservoir is located at a depth of 2.5 km and all other parameters are the same as in the base case. In this scenario, the same amount of CO_2 (2 Mtons) is injected in all cases. Figure 9. shows the CO_2 saturation in the reservoir pore fluid near the production well after the initial 2.5 years of CO_2 injection for CO_2 plume formation. It is clear from the figure that, as the geothermal gradient increases, the CO_2 plume saturation near the production well increases due

to the high CO_2 density difference between the injection and production wells. Therefore more CO_2 is required for locations with low geothermal gradients.

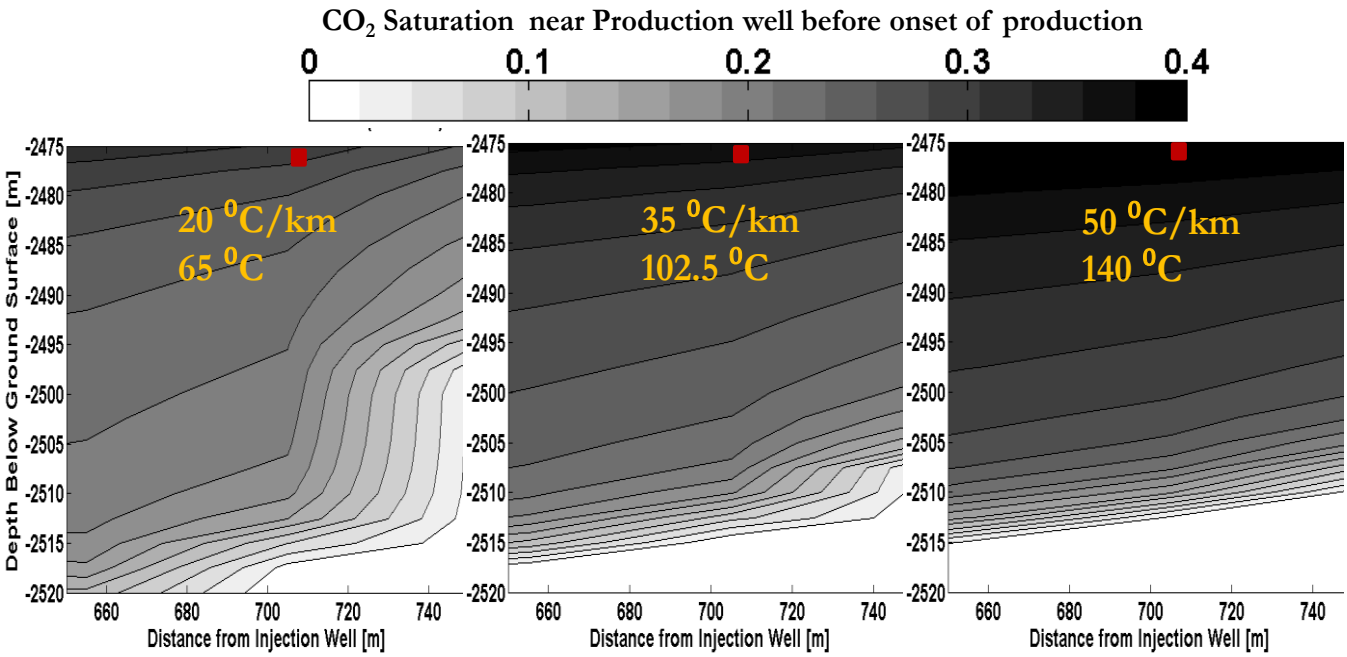

Figure 9. CO_2 saturation in the geothermal reservoir pore fluid after initial CO_2 plume formation by injecting 2 Mtons of CO_2 for geothermal gradients of a) 20°C/km; b) 35°C/km; and c) 50°C/km.

3.2 Heat Contributions

The heat contributions from various sources for the total extracted heat from the geothermal reservoir for the base case are presented in Figure 10.

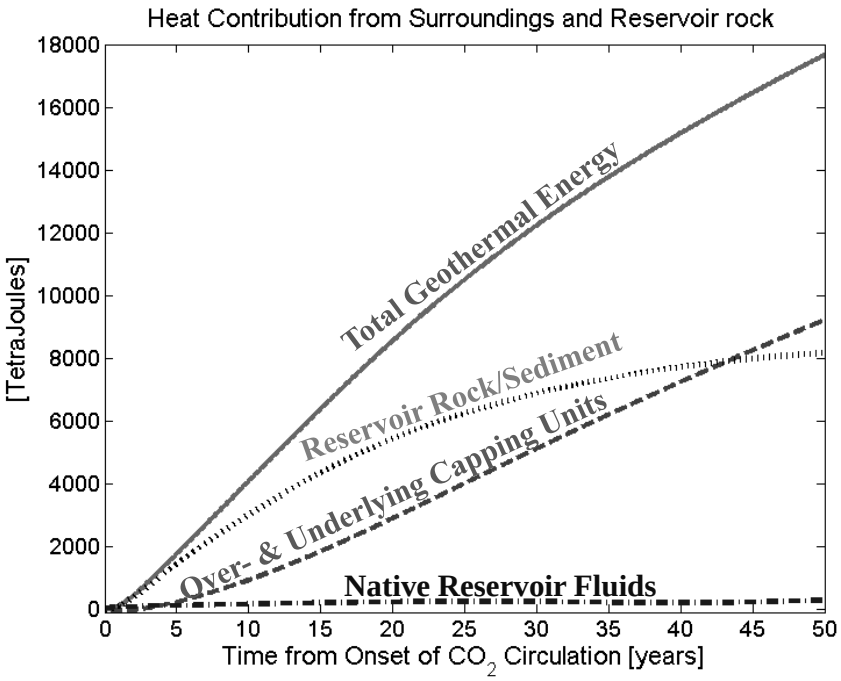

Figure 10. The contribution of reservoir over- and underlying cap rock units, reservoir rock/ sediment, and native fluid to the total amount of heat extracted with time.

The thermal energy extraction rate from the reservoir is estimated as the product of CO_2 mass flow rate and the change in CO_2 enthalpy in the reservoir from injection to production wells. The cumulative amount of heat output is calculated over time by

$$E_{cu} = \sum \dot{m}\left(H_{prod} - H_{inj}\right)\Delta t \,, \tag{1}$$

where E_{cu} is the cumulative heat extracted [Joules], $\dot{m}$ is the mass flow rate [kg/sec], Δt is the time step [second], H_{prod} and H_{inj} are the specific enthalpies of CO_2 at production and injection wells [Joules/kg]. The heat contribution from the surroundings E_{cap} is calculated by employing the semi-analytical heat exchange (Pruess *et al.*, 1999) at the top and bottom of the reservoir, and the amount of heat exchanged is an output from the simulation. The heat contribution from the reservoir rock, E_{rock} is calculated as the difference in the amount of heat from the rock at any given time and the initial amount of heat from the rock. The contribution of heat from native fluids is calculated as shown in Equation (2). The amount of heat contributed due to the background geothermal heat flux is calculated as the difference between the cumulative heat extracted from the reservoir rock with and without heat exchange at the boundaries of the reservoir as shown in Figure 11.

$$E_{fluid} = E_{cu} - E_{cap} - E_{rock} \tag{2}$$

During the initial stages of production the heat contribution is mainly from the reservoir rock, and as the heat is extracted from the reservoir the contribution of the surroundings and the geothermal heat flux increases (Figure 10). The major contribution to the energy output from the reservoir is from the reservoir rock during the early stage of operation while the heat contribution of the native fluid is very low and almost constant throughout operation.

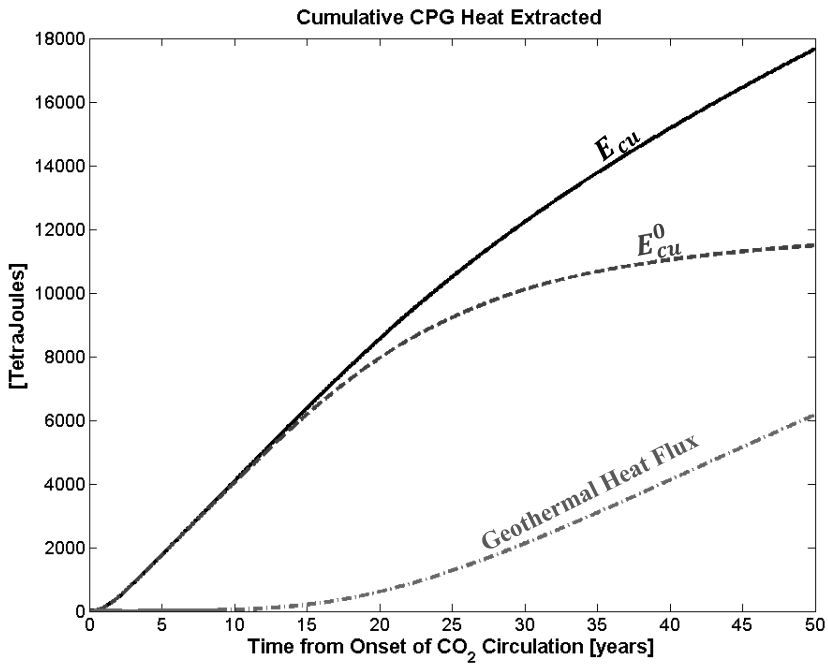

Figure 11. The contribution of geothermal heat flux to the total amount of heat extracted over time is calculated as the difference between the cumulative heat extracted from the reservoir sediment with heat exchange and without heat exchange.

3.2.1 Heat Extraction Rates

The produced fluid flow rate has to be maintained such that it can produce electricity at an economically-competitive cost compared to electricity from other sources. At the same time, longevity of the geothermal reservoir is increased when the reservoir heat is depleted slowly. Figure 12 shows the thermal heat extraction rate from the reservoir with different circulation rates and the drop in temperature of the produced fluid versus time after the onset of CO_2 circulation. If a large circulation rate is used, the heat extraction rate is higher but the temperature of the reservoir reduces at a faster rate, and if the thermosiphon cannot drive and maintain the circulation rate (Adams et al., 2014), then extra pumping might be required, representing a parasitic power requirement. On the other hand, a low CO_2 circulation rate may not be economical, given potentially high drilling and construction costs. Therefore an optimum circulation rate has to be implemented based on the desired longevity of the geothermal reservoir and power production rate.

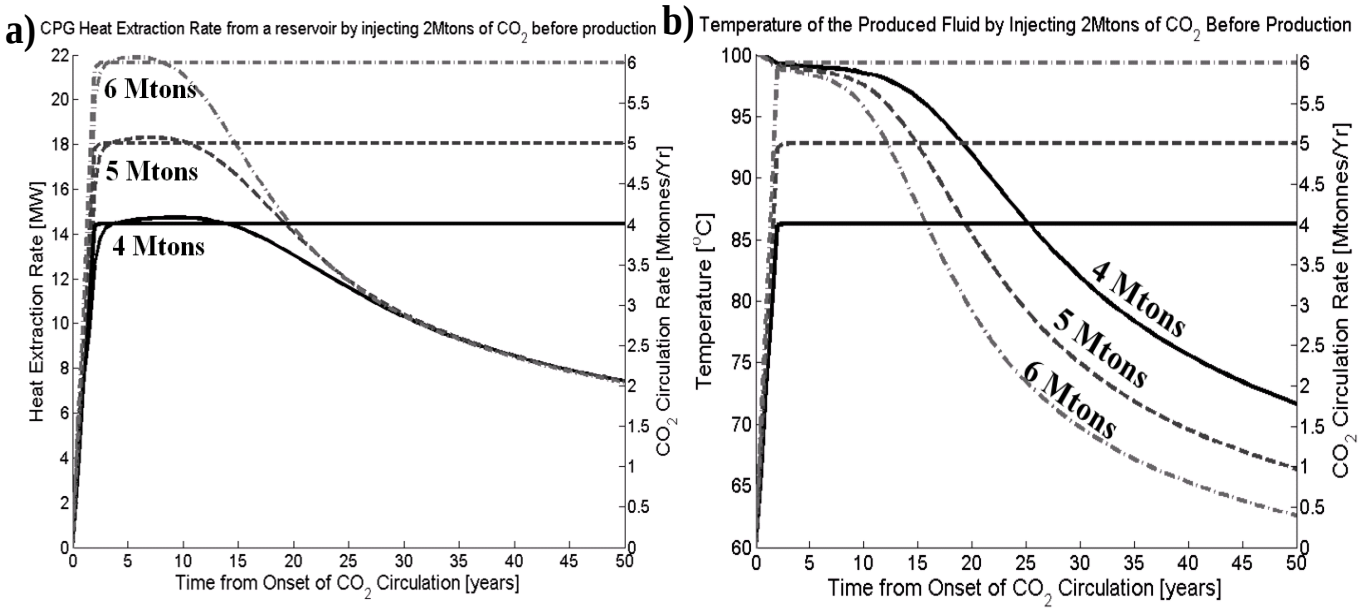

Figure 12. Heat extraction rate versus time (a) for various production rates with the corresponding drop in temperature of the reservoir over time (b). The CO_2 circulation rates through the system are shown by dashed green lines and their magnitude is indicated by the secondary axis.

4 CONCLUSIONS

This study determines the finite amount of CO_2 required for operation of a geologically-simplified CO_2-Plume Geothermal (CPG) system as a function of various parameters such as reservoir volume, temperature, and depth. The amount of CO_2 required increases with reservoir thickness, well spacing between injection and production wells, and with reservoir depth, and decreases for locations with higher geothermal gradients. We also show the contributions of heat from reservoir sediments, native fluid, as well as over- and underlying low permeability cap units to the total amount of geothermal energy extracted. The heat from the reservoir rock contributes the majority of the heat extracted during the initial years of fluid production and circulation while, as the heat from the reservoir sediment starts depleting, the heat contribution from the surrounding units and from the geothermal heat flux increases. The CO_2 production rate has to be designed based on the desired longevity of the geothermal reservoir and power production rates. We show that for an optimal CO_2 circulation rate, with a finite amount of CO_2 injected, a CPG system can operate for several decades with little decrease in produced fluid temperature.

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DISCLAIMER

Drs. Randolph and Saar have a significant financial interest, and Dr. Saar has a business interest, in Heat Mining Company LLC, a company that may commercially benefit from the results of this research. The University of Minnesota has the right to receive royalty income under the terms of a license agreement with Heat Mining Company LLC. These relationships have been reviewed and managed by the University of Minnesota in accordance with its conflict of interest policies.

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