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Coupling carbon dioxide sequestration with geothermal energy capture in naturally permeable, porous geologic formations: Implications for CO_2 sequestration

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Abstract

Carbon dioxide (CO_2) sequestration in deep saline aquifers and 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. 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, as its thermodynamic and fluid mechanical properties suggest it transfers geothermal heat more efficiently than water. Energy production and sales in conjunction with sequestration would improve the economic viability of CO_2 sequestration, a critical challenge for large-scale implementation of the technology. In addition, using CO_2 as the working fluid in geothermal power systems may permit utilization of lower temperature geologic formations than those that are currently deemed economically viable, leading to more widespread utilization of geothermal energy. Here, we present the results of early-stage calculations demonstrating the geothermal energy capture potential of CO_2-based geothermal systems and implications of such energy capture for the economic viability of geologic CO_2 sequestration.

Keywords: Geothermal energy; CPG; CO_2 sequestration

1. Introduction and Background

Geologic CO_2 sequestration is often considered the primary approach with soon-to-be available technology by which anthropogenic CO_2 emissions to the atmosphere could be significantly reduced [1]. However, a challenge for large-scale implementation of sequestration is cost; CO_2 capture and storage (CCS) could add 20%, or more, to the cost of fossil-fuel-based electricity generation, assuming CCS costs of 0.02 $U.S.A. per kWh [2]. Advances in CCS technology and experience, together with legislation such as carbon cap and trade, will improve the economic feasibility of CCS, however, these advances may not be sufficient to encourage large-scale CCS implementation.

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Coupling CCS with renewable energy capture, electricity production, and/or district heating would further improve the economic viability of CCS, among numerous other advantages, as outlined in this contribution.

Geothermal energy offers clean, consistent, reliable electric power with no need for grid-scale energy storage, unlike most renewable power alternatives. However, geothermal energy is often underrepresented in renewable energy discussions and has considerable room for growth (e.g., [3], [4]). New technology and methods will be critical for future investment, and rapid implementation of new techniques will be important to ensure geothermal energy plays a significant role in the future energy landscape worldwide.

CO_2 is of interest as a geothermal working fluid because, among numerous other benefits, its thermodynamic and fluid mechanical properties suggest it transfers geothermal heat more efficiently than water [5], [6]. Previous literature, however, has proposed geothermal energy recovery by CO_2 in the subsurface only in the context of engineered geothermal systems (EGS) [5], [7], [8], [9], [10], [11]. EGS are typically generated by hydrofracturing so-called hot-dry rock, a process that may induce seismicity because the critical fracture stresses of geologic formations are intentionally exceeded. As such, EGS has encountered considerable socio-political resistance, exemplified by the termination of several EGS projects during the year 2009 (e.g., Basel in Switzerland [12]). In contrast, the method described here does not rely on hydrofracturing or similar permeability-enhancing technologies, but rather 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 [13]. Consequently, the CO_2 sequestration potential of the system described here is expected to be significantly greater than that of EGS. Therefore, we distinguish our approach from EGS and refer to it as a CO_2-plume geothermal (CPG) system.

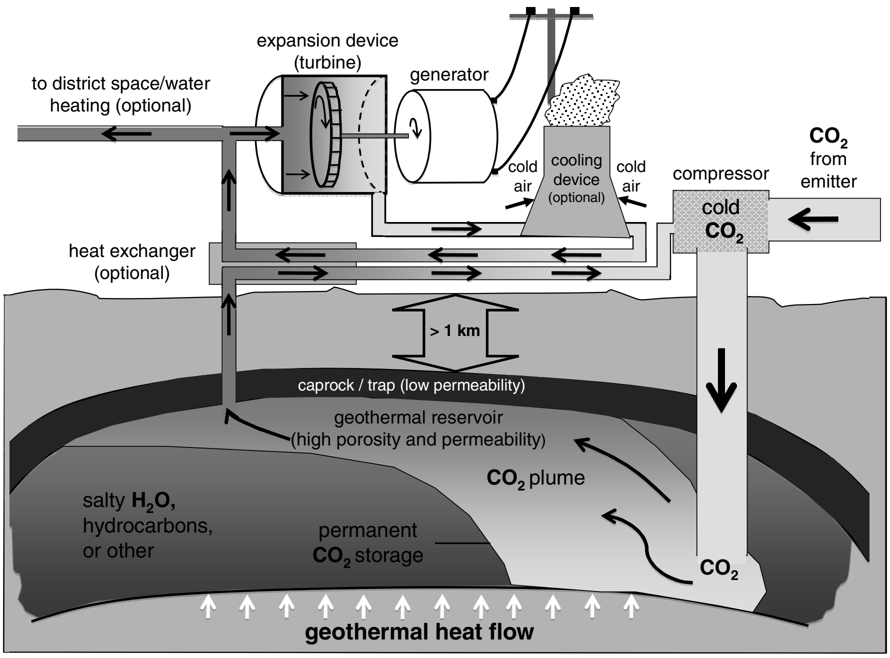

Figure 1 Simplified schematic of one possible implementation of a CO_2-plume geothermal (CPG) system, established in a deep saline aquifer or as a component of enhanced oil/hydrocarbon recovery (EOR) operations. Some components of the system are generalized or absent. As in traditional geothermal approaches, energy recovered from CPG systems could be used both for electricity generation and for space/water heating. Moreover, a wide range of realizations can be envisioned including direct and binary cycles, bottom cycles, and multiple secondary working fluids. Note that only one production well is shown here, while actual implementations would likely include multiple production, and possibly several injection, wells (see also Figure 2 for a typical 5-spot well pattern).

The CPG system involves pumping CO_2 into deep, naturally porous and permeable geologic formations where the CO_2 displaces native formation fluid. The injected CO_2 is heated by naturally elevated (with respect to the surface) underground temperatures and, to some degree, by the geothermal heat flux from Earth's interior to its surface. A small portion of the injected and heated CO_2 is then piped to the surface and either sent through a turbine, powering a generator and producing electricity, or sent through a heat exchanger to provide energy for electricity production and/or district heating in a binary cycle, before being returned to the subsurface. Eventually, all of the injected CO_2 (barring leakage to the surface) is permanently stored via the geologic CO_2 sequestration component of the system.

The present study is focused on the economic benefits of CPG with respect to carbon capture and storage (CCS), in particular, the potential for CPG to offset some of the costs associated with CCS. For detailed comparisons of the CPG approach to traditional water-based geothermal systems as well as to EGS, refer to [6], [14]. The current study is concerned primarily with North America, but its conclusions are applicable worldwide.

2. Methods

The viability of a geothermal system with CO_2 as the working heat exchange fluid in the subsurface has been demonstrated with regards to CPG systems [6], [14] and for CO_2-based EGS [5]. In particular, CPG can provide heat extraction rates up to a factor of three greater than those of traditional water-based systems [6]. Here, we develop numerical simulations to estimate geothermal heat energy extraction in the CPG approach for the purpose of calculating the electricity provided per ton of sequestered CO_2. The most critical geothermal reservoir and fluid injection/production characteristics in an early-stage analysis are reservoir permeability, temperature, pressure, dimensions, 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.

Water-based geothermal electricity production has traditionally, but not exclusively, relied on relatively high temperature (> 150 ^oC), high heat flow (> 90 mW/m^2, approximately) regions. In the U.S.A., where currently most of the world's geothermal electricity production occurs [15], approximately 90% of the geothermal electricity generation capacity takes the form of higher-temperature dry and flash steam systems, as opposed to lower-temperature (< 150 ^oC) binary systems [15], [16]. High temperature systems are generally restricted to the western part of the continent. In contrast, large-scale implementation of CO_2 sequestration will require use of broader CO_2 reservoir targets that frequently will not serve as ideal, high-temperature geothermal reservoirs. Thus, for the purpose of this investigation, we choose, as a base case, a geologic reservoir with more moderate thermal characteristics, as may be encountered in moderate to low geothermal heat flow regions, as found throughout most of Earth's near-surface regions (e.g., [17]). Reservoir (initial) temperature and pressure of 100^oC and 250 bar (2.5km deep formation), respectively, are employed, as 100^oC is often considered the lower limit for geothermal electricity generation [18]. Such temperature and pressure values may be encountered at several potential geologic CO_2 sequestration sites worldwide, including the Williston Basin of North Dakota, U.S.A., and the Alberta Basin in Canada [19]. In addition to the base case, several other temperature and pressure cases are considered for the purpose of exploring parameter space.

A five-spot well configuration (Figure 2) is utilized, as is employed in several early-stage geothermal investigations in the literature (e.g., [5], [10]). To ensure models for the present study function correctly, the models and results of Pruess 2006 [5] were first reproduced. These models employed EGS characteristics, and once agreement was obtained, our simulations were modified to represent naturally porous, permeable systems. The symmetry of the five-spot computational grid reduces modeling requirements to 1/8th of the system domain. The two-dimensional grid consists of 36 primary grid blocks, each with 70.71m side length. Blocks consist of a continuous porous medium matrix with a porosity of 20%, in agreement with several CO_2 sequestration basins including the Williston and Alberta Basins [19].

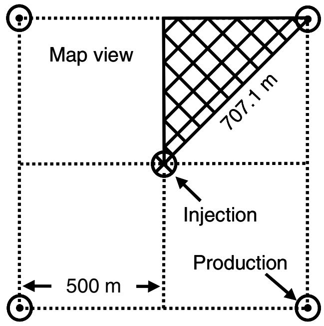

Figure 2 Five-spot well configuration utilized in simulations. By symmetry, only the gridded section of the domain need be simulated.

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 produced fluid and h_o is the fluid enthalpy at injection conditions (at a temperature of 20°C). For a given simulation, the system is assumed to contain CO_2 only. While the displacement of a formation's native brine or other fluid by CO_2 is important, it is not the focus of the current study. Rock thermal characteristics and permeability, the latter set to a conservative value of $5x10^{-14}m^2$, are consistent with values that may typically be encountered at CO_2 sequestration sites [19]. Regarding permeability, fields in the Illinois Basin report values ranging from $3.0x10^{-14}$ to $10x10^{-14}m^2$ [20], whereas the saline aquifer systems of Alberta, Saskatchewan, North and South Dakota, and Montana have values ranging from $9.3x10^{-15}$ to $9.3x10^{-12}m^2$ [19]. All simulations are completed utilizing the well-established reservoir simulator TOUGH2 [21] with the fluid property module ECO2N [22]. Table 1 provides a complete list of model parameters and conditions.

Base Case Parameters			
Geologic formation		Injection/ production conditions	
Thickness	305 meters	Formation map-view area	1 km^2
Well separation	707.1 meters	Temperature of injected fluid	20 °C
Permeability	$5x10^{-14}m^2$	Injection/production rate	max. 300 kg/s (variable)
Porosity	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/°C	Injection/production duration	25 years
Thermal conductivity	2.1 W/m/°C		
Formation initial conditions		Formation boundary conditions	
Fluid in pore spaces	All CO_2	Top and sides	No fluid or heat flow
Temperature	100 °C	Bottom	Heat conduction , no fluid flow
Pressure	250 bar		
Parameters for Additional Cases			
Case number	Temperature	Formation depth	
1	150 °C	4 km (400 bar)	
2	100 °C	1 km (100 bar)	

Table 1 Simulation parameters. For the additional cases, all parameters not specifically defined are taken to be the same as for the base case.

3. Energy Recovery from CO_2-based Geothermal (CPG)

Results of simulations are presented in Table 2. Heat extraction rates are given on a full-well basis (i.e., for the entire five-spot system) and are averaged over the duration of fluid injection and production. 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. Heat extraction rates in the CPG approach generally increase with formation temperature, as may be expected.

Note that Case 1 applies to a relatively deep reservoir in a moderate geothermal heat flow region; such a formation may be encountered in the afore-mentioned Williston Basin [19] but may be less common than the base case. Case 2 applies to a shallow reservoir in a high heat flow region, as may be encountered in the western U.S.A. (refer to Figures 3 and 4 for maps of subsurface temperatures and basins).

Simulation Results	
Case number	Heat extraction rate (25 year average)
Base case	47.0 MW
1	62.6 MW
2	64.1 MW

Table 2 Summary of simulation results for one five-spot well system. In practice, multiple such systems can be envisioned. Note: to determine the amount of electricity produced, system-specific energy losses have to be considered for conversion of heat energy to electricity, as discussed in the main text.

4. Implications for Geologic CO_2 Sequestration

The geothermal energy harnessed in the CPG approach can be utilized for baseload or dispatchable (peak-demand) electricity production or to provide heat for district space/water heating. The highest energy utilization efficiencies can be achieved by providing both electricity and heat, although this restricts the locations of facilities to sites near heat end-users such as industry and/or residences. In the CPG approach, electricity could be supplied to the grid or used onsite to help offset the energy requirements of CCS. Here, we estimate the value of the energy harnessed by CPG with respect to CCS, specifically calculating the value of energy harnessed per ton injected CO_2.

Applying the parameters relevant to the base case simulation (Table 1), we first calculate the total amount of CO_2 sequestered during 25 years of CPG power plant operation. As previously mentioned, displacement of native formation fluid by CO_2 injection is not the objective of the current investigation. The reservoir must be prepped by injecting CO_2 for a period of time prior to producing heated CO_2. For current purposes, we assume that prior to CO_2 withdrawal from production wells, the 1km by 1km by 305m reservoir must be 10% filled with CO_2, which corresponds to approximately 6 months of injection at 280 kg/sec. Thereafter, we assume that averaged over the duration of power plant operation (loss rates are expected to be higher during early plant operation and decrease with time [5]), 7% of injected CO_2 is not recoverable at the production well and must be continuously replaced. Non-recoverable CO_2 is considered permanently stored within the geologic formation, reflecting the CO_2 sequestration component of the system. Pruess [5] utilizes a value of 5% for fluid "loss" (i.e., CO_2 storage) from CO_2-based EGS, and a higher value may be expected in the naturally permeable formations considered here (future studies will examine rates of fluid loss in detail). Note that, eventually, all injected CO_2 is permanently sequestered (barring upward leakage through the caprock) because the CO_2 circulated through the above-ground power plant system is reinjected (Figure 1). Therefore, for the base case, total CO_2 sequestration is 2.0 x 10^7 tons over the simulated 25-year life of the CPG power plant.

Starting with the thermal energy extraction rate (Q), electricity production (W) can be estimated by applying the Carnot efficiency (C) and mechanical system utilization efficiency (E) as $W = C \times E \times Q$. The Carnot efficiency, the theoretical maximum heat energy that can be converted to mechanical work, is defined as $C = 1 - T_{rejection}/T_{reservoir}$, where for the base case, $T_{reservoir}$ = 373.15 K and $T_{rejection}$ is taken to be 283 K (the approximate average annual surface temperature for regions of the northern U.S.A. [23]). Applying E = 0.5 (modified after [24]) and taking Q = 47.0 MW thermal (average value over the 25 year life of the system, full well basis), W = 5.7 MWe.

Gross revenue (R) generated by the sale of this electricity is calculated using $R = W$ *x (hours per year) x (value per MW*hour)*, where (*value per MW*hour*) is taken to be 100 \$U.S.A. [25] and tax incentives are excluded. Power plant construction cost (including exploration, drilling, permitting, plant construction, and transmission) is set at 3 x 10^6 \$U.S.A per MW [25], and operating cost, at 6.5 x 10^4 \$U.S.A. per MW per year [26]. Net revenue, gross revenue minus construction and operating costs, is 8.6 x 10^7 \$U.S.A. over the life of the power plant. This translates, for the base case, to a net revenue of 4.4 \$U.S.A per ton CO_2 sequestered, again assuming a 25-year lifespan of the CPG system. Longer operation times would result in higher net revenue values due to fixed construction and low maintenance costs.

For comparison, Case 1 (temperature = 150 °C, reservoir depth = 4 km) gives a net revenue of 7.9 \$U.S.A per ton CO_2 sequestered whereas Case 2 (temperature = 100 °C, reservoir depth = 1 km) gives net revenue of 5.9 \$U.S.A per ton CO_2 sequestered.

Over the same time span, the net revenue from CPG provides, in the base case, approximately 7.3% of the cost of CCS, assuming a current CCS cost of 60 \$U.S.A. per ton CO_2 (CCS costs range from 16.6 to 91.3 \$U.S.A. per ton for capture from a coal or natural gas power plants [1]). In Cases 1 and 2, the percentage increases to 13.1% and 9.8%, respectively.

More significantly, CPG (base case) could provide 53% to 730% of the cost of geologic CO_2 sequestration and monitoring/verification (excluding CO_2 capture), assuming storage and monitoring/verification costs of 0.6 – 8.3 \$U.S.A. per ton CO_2 [1]. For Cases 1 and 2, the ranges are 95% to 1300% and 71% to 980%, respectively. While the CO_2 injection and partial sequestration component of enhanced hydrocarbon recovery is generally considered economically feasible, traditional deep saline aquifer CO_2 sequestration is not. These results suggest that **combining geothermal energy capture with sequestration, i.e., CPG, vastly improves the economic feasibility of the CO_2 sequestration component in deep saline aquifer CCS**.

Rather than considering the revenue generated by CPG in the context of the cost of CCS, we may also examine CPG with respect to the carbon price required to achieve certain reductions in atmospheric CO_2 emissions. According to the IPCC 2007 report [1], a carbon price of 31 \$U.S.A per ton CO_2 (the mean value of 12 scenarios) by 2030 delivers emissions trajectories that lead to stabilization of atmospheric CO_2 concentration at category III levels (440 – 485 ppm). The CPG scenarios investigated here provide revenue in the range of 4.4 – 7.9 \$U.S.A. per ton CO_2, or 14 – 25% of the above indicated carbon price. With widespread utilization of CPG, therefore, lower carbon prices could provide the same incentive to sequester CO_2, and hence reduce atmospheric CO_2 emissions, as higher carbon prices without CPG. In general, lower carbon prices (i.e., taxes) should be easier to implement.

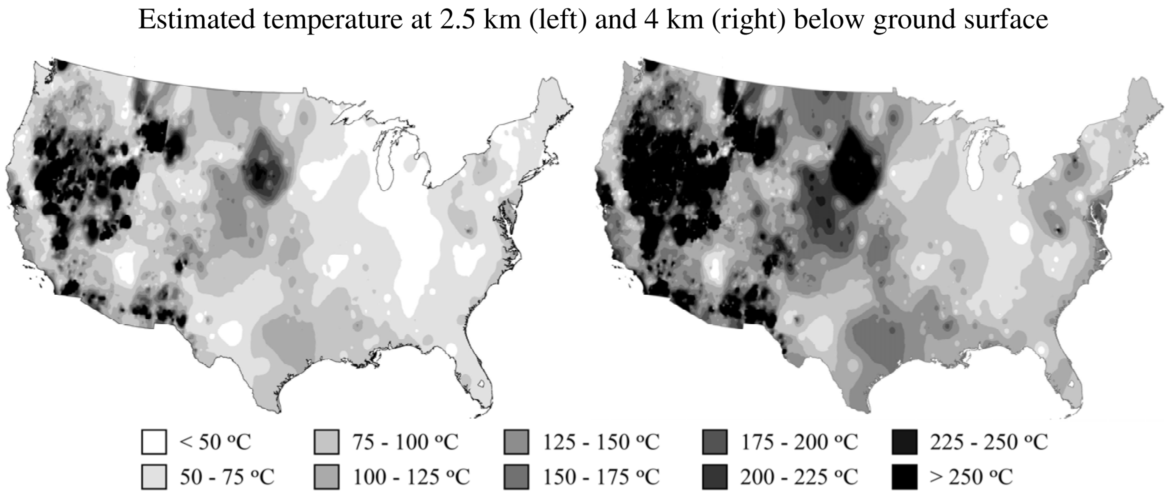

Figure 3 Contiguous U.S.A. temperature maps at 2.5 (left) and 4 km (right) depths. Comparing these maps with the locations of sedimentary basins in the U.S.A., shown in Figure 4, reveals that such basins are often present in regions with moderate to high subsurface temperatures. Thus, with regards to temperature, such sedimentary basins, if utilized for CO_2 sequestration, could also be employed for geothermal energy capture employing CPG systems.

Figure 4 Map of sedimentary basins worldwide ([27], from IPCC 2007 report [1]) that may serve as reservoirs for geologic CO_2 sequestration. For the work presented here, particularly note the locations of basins in the United States.

In addition to sequestering CO_2, the CPG approach avoids atmospheric emissions by supplying energy from non-CO_2-emitting, renewable energy sources, as geothermal energy may be considered renewable over human time scales, in stark contrast to hydrocarbon-based energy. Assuming a standard coal-fired power plant produces 30 tons

CO_2 per MWe per day [28], the electricity supplied by the base case CPG power plant avoids 1.6 x 10^7 tons of CO_2 over the duration of power plant operation, similar in magnitude to the quantity of CO_2 directly sequestered.

5. Concluding Remarks

While additional research is required, numerical modeling results at present suggest that geologic reservoirs with CO_2 as the subsurface heat mining fluid (i.e., CPG systems) could substantially offset the costs of CCS, and in particular the sequestration component of CCS. In addition, CPG systems would serve as clean, renewable geothermal energy sources for electric power production, potentially even in regions worldwide with moderate to low geothermal temperatures and subsurface heat flow rates.

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