Multifluid geo-energy systems: Using geologic CO₂ storage for geothermal energy production and grid-scale energy storage in sedimentary basins

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ABSTRACT

We present an approach that uses the huge fluid and thermal storage capacity of the subsurface, together with geologic carbon dioxide (CO₂) storage, to harvest, store, and dispatch energy from subsurface (geothermal) and surface (solar, nuclear, fossil) thermal resources, as well as excess energy on electric grids. Captured CO₂ is injected into saline aquifers to store pressure, generate artesian flow of brine, and provide a supplemental working fluid for efficient heat extraction and power conversion. Concentric rings of injection and production wells create a hydraulic mound to store pressure, CO₂, and thermal energy. This energy storage can take excess power from the grid and excess and/or waste thermal energy and dispatch that energy when it is demanded, and thus enable higher penetration of variable renewable energy technologies (e.g., wind and solar). CO₂ stored in the subsurface functions as a cushion gas to provide enormous pressure storage capacity and displace large quantities of brine, some of which can be treated for a variety of beneficial uses. Geothermal power and energy-storage applications may generate enough revenues to compensate for CO₂ capture costs. While our approach can use nitrogen (N₂), in addition to CO₂, as a supplemental fluid, and store thermal energy, this study focuses on using CO₂ for geothermal energy production and grid-scale energy storage. We conduct a techno-economic assessment to determine the levelized cost of electricity using this approach to generate geothermal power. We present a reservoir pressure management strategy that diverts a small portion of the produced brine for beneficial consumptive use to reduce the pumping cost of fluid recirculation, while reducing the risk of seismicity, caprock fracture, and CO₂ leakage.

INTRODUCTION

Climate change mitigation requires a range of measures to reduce CO₂ emissions, the most important being increased reliance on electricity generated from renewable and low-carbon energy resources, and reduced CO₂ intensity of fossil energy use. Due to the inherent variability of wind and solar energy resources, these renewable energy technologies must be matched with energy storage in order to reach their full potential. However, there are currently no energy storage technologies that are economically feasible, sufficiently scalable, and widely deployable. The subsurface, with its vast volumes and high pressures, has the capacity to transform intermittent renewables into base-load and load-following power with carbon-neutral (or carbon-negative) storage.

Geologic CO₂ storage (GCS) in sedimentary basins is a promising approach that can reduce CO₂ intensity of fossil energy use, but the high cost of capturing CO₂ requires valuable uses for CO₂ to justify those costs. Our proposed approach (Figs. 1 and 2) of using GCS to generate geothermal energy and store energy is designed for locations where a permeable sedimentary formation is overlain by a caprock that is impermeable enough to constrain the vertical migration of buoyant, pressurized CO₂. In our approach, the initial charging of the system requires permanently isolating large volumes of captured CO₂ and thus creates a market for its disposal. Once charged, our system can take power from, and deliver power to, electricity grids in a way that mitigates issues with high penetration of variable wind and solar energy sources (e.g., reduce curtailments of wind power deliveries during periods of high winds and low loads). Our approach also constrains the potential migration of CO₂ while the well field is being operated, and reduces the potential for CO₂ leakage long after well-field operations have ceased.

The proposed use of supercritical CO₂ to extract geothermal energy has evolved over the past two decades. The use of supercritical CO₂ as a working fluid in geothermal systems was first proposed for enhanced or engineered geothermal systems (EGS) in low-permeability, hot crystalline basement rocks (Brown, 2000; Pruess, 2006). As a heat extraction fluid, CO₂ has multiple thermophysical advantages, including (1) low kinematic viscosity, compared to brine, allowing for effective heat advection despite its relatively low heat capacity; and (2) high thermal expansibility, compared to brine, generating a much stronger thermosiphon effect through the injection well, the reservoir, and the production well.
Figure 1. Components of a multifluid geo-energy system, including four rings of horizontal injection and production wells. Supercritical CO₂ from a fossil fuel power plant is pressurized for injection in the second ring of wells, which displaces brine produced at the inner ring. Gradually, the inner ring produces CO₂, which is sent through a Brayton cycle turbine and pressurized for injection in the second ring. Brine produced at the inner and outer well rings is sent through a power plant, such as an organic Rankine cycle turbine, stored in a staging pond, and pressurized for injection in the third well ring, using excess power from the grid. To manage pressure, some of the produced brine is diverted for consumptive use, such as in a reverse osmosis plant. The production of pressurized CO₂ and brine can be varied to provide dispatchable power to the grid. Although not shown in this figure, each well ring includes multiple horizontal wells. Also not shown in this figure are field multifluid separators that separate produced brine from the CO₂ produced from the inner ring of wells.
These and other advantages of CO₂ over brine can reduce or eliminate the need for pumps to circulate the working fluid through the reservoir (Atrens, et al., 2009, 2010; Adams et al., 2014). Furthermore, CO₂ typically exhibits diminished fluid-mineral reaction characteristics while some possibly increased reactivity is likely restricted to a narrow region that migrates as the CO₂ plume grows (Luhmann et al., 2014; Tutolo et al., 2014, 2015a, 2015b).

**CO₂ Plume Geothermal**

CO₂ plume geothermal (CPG) differs from CO₂-EGS (Brown, 2000; Pruess, 2006), because CPG extracts heat from sedimentary or stratigraphic reservoirs that have naturally high permeability and are much larger than the artificially generated EGS reservoirs (Randolph and Saar, 2011a, 2011b, 2011c; Saar et al.,...
Sedimentary formations are an underexplored geothermal play concept because they are typically associated with lower reservoir temperatures. However, because sedimentary reservoirs are much larger, with higher permeability than either hydrothermal upflows or artificially created EGS reservoirs, they have lower, more predictable drilling risk than typically associated with hydrothermal or EGS systems. Furthermore, these large and often naturally highly permeable reservoirs can hold large amounts of CO\textsubscript{2} that can take up the heat that is widely distributed throughout the reservoir, resulting in a significant energy source despite the relatively low temperatures (\textasciitilde 100 °C) of such fairly shallow (\textasciitilde 3 km deep) reservoirs. These stratigraphic reservoirs underlie approximately half of North America and are common throughout the world (Metz et al., 2007; Runkel et al., 2007; Coleman and Cahan, 2012; National Renewable Energy Laboratory, 2015). These reservoirs are also the target of GCS efforts (Metz et al., 2005). Coupling CPG with a GCS project creates a CO\textsubscript{2} capture utilization and storage opportunity that can defray the cost of GCS by using CO\textsubscript{2} as a resource to generate electricity. As discussed in the following, CO\textsubscript{2} can also be used as a valuable resource that enables grid-scale energy storage.

**Multifluid Geo-Energy Systems**

Multiple heat extraction fluids (CO\textsubscript{2}, N\textsubscript{2}, and brine) have been proposed (Buscheck et al., 2013c, 2014a), as well as options for providing bulk energy storage (BES) and thermal energy storage (Buscheck et al., 2014b). This versatile multifluid geo-energy system approach injects what we call supplemental fluids (CO\textsubscript{2}, N\textsubscript{2}), in addition to native brine in order to create moderately overpressured reservoir conditions and to provide multiple working fluids for pressure augmentation, energy storage, and energy withdrawal (Buscheck, 2014a, 2014b; Buscheck et al., 2015). Fluid-recirculation efficiency and per well fluid production rates are increased by the supplemental fluids and their advantageous thermophysical properties. Pressure augmentation is improved by the self-convecting thermostopon effect that results from density differences between injection and production wells (Adams et al., 2014). The supplemental fluids are geothermally heated to reservoir temperature, greatly expand, and thus increase the artesian flow of brine and supplemental fluid at the production wells.

The multifluid geo-energy system approach uses a well pattern with a minimum of four concentric rings of producers and injectors (Figs. 1 and 2). This design creates a hydraulic mound to store pressure and supplemental fluids (CO\textsubscript{2} and/or N\textsubscript{2}), segregate the supplemental fluid and brine production zones, and generate large artesian flow rates to better leverage the productivity of the wells, particularly useful for long-reach horizontal wells. Due to buoyancy, the supplemental fluids migrate to the top of the permeable reservoir to form a cushion gas cap to provide the pressure storage capacity of the system (Fig. 2). Together with the impermeable caprock and bedrock, the hydraulic mound forms a container to store pressure, CO\textsubscript{2} and/or N\textsubscript{2}, and enable BES (Buscheck et al., 2014a, 2014b, 2015; Edmunds et al., 2014). The hydraulic trough is, effectively, at the base of the spillway of this energy storage system (Fig. 2).

Because fluid production is driven by stored pressure, submersible pumps are not required to lift fluid up production wells; thus, it is possible to more quickly increase production when power demand is high or when there is a deficit of other renewable energy on the grid. It may also be desirable to decrease or even curtail production when demand is low or when there is a surplus of other renewable energy on the grid, which would serve to further store pressure and thermal energy for use when demand exceeds supply. Supplemental fluid injection enhances fluid production rates in several ways. The thermosiphon effect can result in large supplemental fluid production rates. Supplemental fluid injection also displaces brine to where it is produced at the inner production ring, creating make-up brine. Most of the make-up brine is re-injected into the third ring of wells to increase gross power output, while some may be used to cool the power plant and reduce its water intensity, which can be useful in regions of water scarcity.

A key feature of the multifluid geo-energy system approach is the option to time shift the pumping load associated with fluid recirculation to achieve BES. As analyzed in Buscheck et al. (2015), the pumping load is dominated by the power required to pressurize and inject brine. By comparison, the power required to compress and inject CO\textsubscript{2} is negligible, while the power required for N\textsubscript{2} injection is \textasciitilde 10%–25% that of brine. Because N\textsubscript{2} can be readily separated from air and produced brine can be temporarily stored in brine staging ponds (Fig. 1), N\textsubscript{2} and brine pressurization and injection can be scheduled during periods of low power demand or when there is a surplus of renewable energy on the grid. Time shifting when the pumping load is imposed can reduce the cost of powering fluid recirculation, in addition to providing BES. Thus, multifluid geo-energy systems can be pressurized (recharged) when supply exceeds demand and depressurized (discharged) when demand exceeds supply, similar to pumped storage hydroelectricity (PSH). Because of their compressibility, supercritical CO\textsubscript{2} and N\textsubscript{2} cushion gases increase the pressure storage capacity of the system and dampen pressure fluctuations caused by cyclic pressurization and depressurization. This cushion-gas function is similar to compressed air energy storage, but, unlike air, N\textsubscript{2} is not corrosive and will not react with the reservoir formation. Although CO\textsubscript{2} can react somewhat with the reservoir formation, that interaction has far less corrosive consequences than that of air.

The multifluid geo-energy system approach has operational advantages over geothermal systems that require submersible pumps. Large centralized pumps located on the surface (Fig. 1) should be more efficient than submersible pumps. Moreover, surface-based pumps would not be exposed to the harsh conditions in production wells and would not require frequent maintenance that could disrupt production. When surface-based pumps require servicing, access is much easier than for submersible pumps. The multifluid geo-energy system would be particularly valuable in hydrostatic reservoirs where temperatures are too hot (>200 °C) for submersible pumps, and it could also produce flow rates that are greater than the capacity of submersible pumps. Because BES capacity increases with the ability to store pressure and because pressure storage capacity increases with cushion gas volume, BES capacity increases with stored CO\textsubscript{2} and N\textsubscript{2} mass.
Reservoir Pressure Management

Because sedimentary basins are associated with lower resource temperatures, in order to achieve sufficient per well heat extraction rates and financial viability, injection and production wells need to be spaced farther apart than the typical well spacing in hydrothermal systems. Enabling working fluid recirculation between widely spaced wells will result in greater fluid over-pressure ($\Delta P$), defined to be fluid pressure in excess of ambient pressure. Larger $\Delta P$ increases the power necessary to pressurize and inject brine, and results in a greater pumping load to drive fluid recirculation than in hydrothermal power systems. If a constant net storage rate of CO$_2$ is maintained during a project lifetime of 30 yr, the magnitude of overpressure can be large (Buscheck et al., 2015), resulting in large brine reinjection costs, as well as increasing the risk of induced seismicity and caprock fracture. We address these concerns with a reservoir pressure management strategy that diverts a small portion (<5% for a net CO$_2$ storage rate of 120 kg/s) of the produced brine for beneficial consumptive use, such as for fresh water, generated by either reverse osmosis or flash distillation, or for power plant cooling. This strategy results in multiple benefits: (1) reducing the pumping load of fluid recirculation, which improves power generation efficiency; (2) creating more pore space for CO$_2$ storage, enabling greater quantities of CO$_2$ to be stored with reduced risk of caprock failure, CO$_2$ leakage, and induced seismicity; and (3) providing a source of water that could be used for cooling or other purposes.

RESERVOIR MODELING METHODOLOGY

We conduct reservoir analyses with the nonisothermal unsaturated flow and transport (NUFT) numerical simulator, which simulates multiphase heat and mass flow and reactive transport in porous media (Nita0, 1998; Hao et al., 2012). NUFT has been used extensively in reservoir studies of GCS and of multifluid geo-energy systems (Buscheck et al., 2012, 2013b, 2013c, 2014a, 2014b, 2015; Saar et al., 2015). The values of pore and water compressibility are $4.5 \times 10^{-10}$ Pa$^{-1}$ and $3.5 \times 10^{-10}$ Pa$^{-1}$, respectively. Water density was determined by the American Society of Mechanical Engineers (2006) steam tables. The two-phase flow of supercritical CO$_2$ and water is simulated with the density and compressibility of supercritical CO$_2$ determined by the correlation of Span and Wagner (1998) and CO$_2$ dynamic viscosity given by the correlation of Fenghour et al. (1998). Where the injection of supercritical N$_2$ is considered (Buscheck et al., 2014a, 2015), the two-phase flow of supercritical N$_2$ and water is simulated with the density and compressibility for N$_2$ determined by the correlation of Span et al. (2000), and the dynamic viscosity is taken from Lemmon and Jacobsen (2004).

For this study, a generic system (Fig. 2) is modeled over the course of 30 yr. The system consists of a 125-m-thick reservoir with a permeability of $1 \times 10^{-13}$ m$^2$, bounded by low-permeability seal units (caprock and bedrock), each with a permeability of $1 \times 10^{-16}$ m$^2$. Hydrologic properties (Table 1) are similar to previous GCS and multifluid geo-energy studies (Zhou et al., 2008; Buscheck et al., 2013a, 2013b, 2013c, 2014a, 2014b, 2015; Saar et al., 2015; Elliot et al., 2013). Because the reservoir, the caprock, and the bedrock are assumed to be laterally homogeneous, we use a radially symmetric (RZ) model. We qualitatively discuss some of the expected consequences of relaxing the assumption of lateral homogeneity in the reservoir and the sealing units.

We assumed a geothermal heat flow of 75 mW/m$^2$ that occurs over large portions of the conterminous U.S. (Blackwell et al., 2011) and reservoir bottom depths of 3, 4, and 5 km. This results in a geothermal gradient of 37.5 °C and initial temperatures of 1270, 164.5, and 202.0 °C at the bottom of the reservoir for the 3 depths, respectively, assuming an average thermal conductivity of 2.0 W m$^{-1}$ °C$^{-1}$ (Table 1) and an average surface temperature of 14.5 °C. The RZ model is thus a simplified representation of an actual system, but likely representative of rings of arc-shaped horizontal wells (see Garapati et al., 2015, appendices therein), which in actual geothermal reservoir system implementations may be horizontal partial circles that intercept inclined reservoir caprock or vertically offset fault interfaces. The RZ model allows fine mesh refinement, particularly around the injectors and producers, to better model pressure gradients close to the wells. The dimensions of the four-ring well configuration are shown in Figure 2.

For this study, NUFT is used to model pure supercritical CO$_2$ injection. For power generation, two parallel production streams (supercritical CO$_2$ and brine) determined by the reservoir model are used to calculate gross power. For the brine production stream, we determine gross power for organic Rankine cycle (ORC) binary power generation for reservoir depths of 3 and 4 km, while for a reservoir depth of 5 km we determine gross power for a flash-steam power plant. For both the binary cycle and flash-steam power plants, gross power is calculated using the production flow rates and temperatures determined by the reservoir model, and the brine effectiveness determined by the U.S. Department of Energy Geothermal Electricity Technology Evaluation Model (GETEM) code (U.S. Department of Energy, 2012). The pumping load of pressurizing and reinjecting CO$_2$ and brine are determined for a pump efficiency of 80%, subject to the reservoir depth and overpressure. Because we use large surface-based pumps, efficiency is somewhat higher than that associated with submersible pumps.

For the supercritical CO$_2$ production stream, gross power is determined for electricity generated using a Brayton cycle (direct cycle) power system, in

<table>
<thead>
<tr>
<th>Property</th>
<th>Reservoir (caprock and bedrock)</th>
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<tbody>
<tr>
<td>Permeability (m$^2$)</td>
<td>$1.0 \times 10^{-13}$</td>
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<tr>
<td>Thermal conductivity (W/m °C)</td>
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<td>Porosity</td>
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<td>van Genuchten (1980) m</td>
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<td>van Genuchten (1980) $\alpha$ (1/Pa)</td>
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<td>Residual brine saturation</td>
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which the produced CO₂ is sent through a turbine rather than a binary cycle or flash-steam power system. Unless the resource temperature is ≥200 °C, when CO₂ is the working fluid, Brayton cycle power systems offer greater energy conversion efficiency than ORC binary systems (Adams et al., 2014) because the supercritical fluids generate a substantial usable pressure difference between the hot production wellhead and the cold injection wellhead (across the turbine), whereas Joule-Thomson cooling reduces produced fluid temperature (Adams et al., 2014). We assume that produced brine has been separated from the produced CO₂ prior to sending the CO₂ through the turbine to generate electricity. Note that when brine and CO₂ are coproduced, enthalpy is transferred to the brine in the CO₂ as the fluids flow up the wellbore, and as the CO₂ cools due to the Joule-Thomson effect. Because the energy penalty for fluid separation is minor, we have not included it in our power-generation analyses. All produced CO₂ is reinjected into the second ring of wells and either all or a portion of the produced brine (minus a small portion as described in the following) is reinjected into the third ring of wells (Fig. 2). It is assumed that the exit temperature of the brine from the binary cycle or flash-steam power plant cools due to the Joule-Thomson effect. Because the energy penalty for fluid separation is minor, we have not included it in our power-generation analyses. All produced CO₂ is reinjected into the second ring of wells and either all or a portion of the produced brine (minus a small portion as described in the following) is reinjected into the third ring of wells (Fig. 2). It is assumed that the exit temperature of the brine from the binary cycle or flash-steam power plant cools due to the Joule-Thomson effect. Because the energy penalty for fluid separation is minor, we have not included it in our power-generation analyses.

In contrast, CO₂ is a poor solvent for minerals; thus a CO₂ power system can cool the fluid within a few degrees of the ambient temperature without concern for mineral precipitation (Adams et al., 2014). After CO₂ has passed through the Brayton cycle turbine, CO₂ is assumed to have been cooled to such a temperature at the injection well head that after compression in the injection well the temperature of the CO₂ entering the reservoir at depth is 25 °C. The lower exit temperature also contributes to the efficiency advantage of the Brayton cycle turbine (Adams et al., 2014). The CO₂ that is directly delivered from the fossil-energy system source is also assumed to enter the reservoir at 25 °C.

Past work (see Buscheck et al., 2014a) found that net CO₂ storage rates associated with CO₂ captured from fossil-energy power plants can lead to large ΔP values in the reservoir that increases the pumping load for pressurizing and injecting brine, and reduces power-system efficiency. To improve efficiency, we implement a reservoir pressure management strategy where a small portion of the produced brine is diverted for beneficial consumptive use once the target ΔP is reached. This target ΔP may also be affected by environmental considerations.

Table 2 summarizes the cases considered in this study. For each reservoir depth, two net CO₂ storage rates are considered: (1) 120 kg/s (3.79 MT/yr) and 240 kg/s (7.57 MT/yr). These CO₂ storage rates correspond to capturing 90% of the CO₂ emitted by 550 and 1100 MW coal-fired power plants, respectively, operating at 90% capacity (Buscheck et al., 2012). For each of those cases, three reservoir pressure management cases are considered for injection-well target ΔP values of 6, 8, and 10 MPa (Fig. 3). Initially, all produced brine is reinjected until the target ΔP is reached at the brine-injection wells, and then a sufficient

<table>
<thead>
<tr>
<th>Resource depth (km)</th>
<th>Target overpressure (MPa)</th>
<th>Net CO₂ storage rate (kg/s)</th>
<th>Number of producers and injectors</th>
<th>Well-development cost (millions of U.S. dollars/well)</th>
<th>Power-plant cost (U.S. dollars per net kW)</th>
<th>LCOE* (greenfield and brownfield) (U.S. cents/kWh)</th>
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*LCOE—levelized cost of electricity; greenfield case—new reservoir site where the total project cost includes all exploration and well-field development costs; brownfield case—a previously exploited, mature reservoir site where all exploration and well-field development costs have already been paid for and are therefore not included in the total project cost.
Figure 3. Overpressure (∆P) history is plotted at the brine and CO₂ injection wells for all cases considered in this study, which includes reservoir depths of 3, 4, and 5 km and net CO₂ storage rates of 120 kg/s and 240 kg/s. The three values of target overpressure ∆P are 6, 8, and 10 MPa.
portion of the brine is diverted for beneficial consumptive use so that $\Delta P$ never exceeds the target value. At a later time, when $\Delta P$ at the CO$_2$ injection wells exceeds that of the brine injection wells, $\Delta P$ at the CO$_2$ injection wells is never allowed to exceed the target value.

## TECHNO-ECONOMIC ASSESSMENT METHODOLOGY

To conduct the techno-economic analyses we applied an advance copy of the newest release of GETEM (U.S. Department of Energy, 2015). GETEM is a Microsoft Excel spreadsheet–based tool that uses financial and technical inputs and optimizes reservoir and power plant performance in order to estimate the levelized cost of electricity (LCOE) from a geothermal power plant. This advanced copy of GETEM incorporates updated information about economic factors, such as well drilling costs. GETEM has five major sections: resource exploration and confirmation, well-field development, reservoir management, conversion system, and economics. We incorporate most of the default values for GETEM, such as a fixed charge rate of 10.8% and an operating lifetime of 30 yr, as well as permitting cost. Modifications to the default values are described in the following.

GETEM does not directly incorporate all features and assumptions related to multifluid geo-energy systems. To address this, we replaced several GETEM default values and made several conservative assumptions about the relationship of our system components to those assumed in GETEM. Because the default drilling costs in GETEM are applicable to igneous and metamorphic rock settings, rather than to sedimentary formations, we increased the well-drilling penetration rates to be more representative of drilling in softer rock, resulting in the well-development costs listed in Table 2. Because our system will be applied to large sedimentary basins that are amenable to GCS, we assumed that only one site is investigated during the exploration phase and fewer exploration wells are required. Our approach utilizes overpressure generated by CO$_2$ injection to drive artesian flow to production wells. Thus, we assume that the confirmation phase is not required in the development of a multifluid geo-energy project.

Although our approach uses above-ground pumps for pressuring and injecting CO$_2$ and brine, rather than subsurface pumps to lift brine up production wells, we incorporate GETEM defaults used to determine capital and operating and maintenance costs for pumping. Thus, we implicitly assume that costs associated with subsurface injection pumps in GETEM are at least as large as those applicable to the surface-based pumps applicable to multifluid geo-energy systems. Note that the energy costs for the pumps in our system are determined outside of GETEM, as described in the discussion of reservoir modeling methodology. In GETEM, the default operational lifetime for subsurface pumps is only 3 yr. Because they are subject to less harsh conditions, above-ground pumps used in multifluid geo-energy systems are likely to last longer than 3 yr and require less frequent maintenance. Therefore, incorporating GETEM pumping-cost assumptions is conservative.

The RZ model used in the reservoir analyses determines the total production rates for the parallel CO$_2$ and brine production streams (Fig. 4), but it cannot determine individual well rates. Because our system generates artesian flow, we assume an average well rate of 120 kg/s for combined CO$_2$ plus brine flow. Note that the inner ring of wells coproduce CO$_2$ and brine, while the outer ring of wells only produce brine. In nonidealized (real) systems with lateral heterogeneity, CO$_2$ may break through to the inner ring of wells sooner than in the idealized system with lateral homogeneity we modeled, because preferential flow paths may result from heterogeneous reservoir permeability, and viscous and capillary fingering due to the nonuniform displacement of native brine by supercritical CO$_2$ (Wang et al., 2013). The pressure mound isolates the CO$_2$ that is injected in the second ring from the brine that is produced in the outer ring; therefore, we do not expect that CO$_2$ would break through to the outer ring of wells. Faults, fractures, or other discontinuities that increase the permeability of the sealing units may reduce the magnitude of the overpressure in the pressure mound, but such seepage should not lead to horizontal breakthrough of CO$_2$ to the outer ring of brine producers.

To determine the number of production wells required to maintain the total flow rate, the 30 yr averaged combined (CO$_2$ plus brine) production rate (Fig. 4) is divided by 120 kg/s; the results are listed in Table 2. We apply the GETEM default of 0.75 injectors per producer to determine the number of injectors (see Table 2). Although it may be advantageous to use horizontal injectors and producers, for calculating LCOE we assume that only vertical wells are used.

Thermal decline is negligible during the first 20 yr of production for all cases (Fig. 5); thereafter it is generally small, except for cases with high net CO$_2$ storage rate and high target $\Delta P$. Therefore, we applied a thermal decline rate of 0.1%/yr in GETEM, which is conservative because (1) fluid production rates (along with heat extraction rates) are somewhat greater for early time (Fig. 4), and (2) net present value is more sensitive to early-time production history than to late-time production. We use the GETEM-optimized value for brine effectiveness for reservoir depths of 4 and 5 km. For a reservoir depth of 3 km, we modify the resource temperature to obtain a power plant cost of $3200/ net kW ($ is U.S. dollars), as this is the value considered to be applicable to Brayton cycle CO$_2$ turbines, as discussed in the following.

Table 2 lists the power plant costs for all cases. For a reservoir depth of 3 km, we assumed that Brayton cycle CO$_2$ turbines will be used in the entire power block because, as discussed here, they are more efficient than ORC binary cycle power systems, with enthalpy from the produced brine being transferred to the produced CO$_2$, or to CO$_2$ that is recirculated in above-ground closed loops. The efficiency of Brayton cycle CO$_2$ turbines increases with power output, with power plant cost decreasing from $3500/ net kW for a 5–10 MW power plant, to $1500/ net kW for a 300 MW power plant. The power plant costs in Table 2 are consistent with that range. Note that the estimated Brayton cycle CO$_2$ turbine power plant cost includes the cost of heat exchangers required to transfer enthalpy from the produced brine to the produced CO$_2$ or above-ground recirculated CO$_2$, as well as all cooling and pumping and compression equipment required to inject CO$_2$. 

To address this, we replaced several GETEM default values and made several conservative assumptions about the relation-
Figure 4. Total mass flow rate history for brine and CO₂ production is plotted for all cases considered in this study, which includes reservoir depths of 3, 4, and 5 km and net CO₂ storage rates of 120 kg/s and 240 kg/s. The three values of target over-pressure $\Delta P$ are 6, 8, and 10 MPa.
Figure 5. Temperature history is plotted for the inner and outer production well rings for all cases considered in this study, which includes reservoir depths of 3, 4, and 5 km and net CO₂ storage rates of 120 kg/s and 240 kg/s. The three values of target over-pressure $\Delta P$ are 6, 8, and 10 MPa.
For GETEM to appropriately size the above-ground facilities, we adjust the average well fluid production rate until GETEM generates the same net power as determined by the reservoir model. LCOE is determined for greenfield cases, which pertain to new reservoir sites where the total project cost includes all exploration and well-field development costs. LCOE is also determined for brownfield cases, which pertain to previously exploited, mature reservoir sites where all exploration and well-field development costs have already been paid for and are therefore not included in the total project cost. The brownfield value of LCOE isolates the above-ground costs, while the difference between the greenfield and brownfield values of LCOE isolates the well-development costs.

## RESULTS AND DISCUSSION

### Reservoir Pressure Management

During the initial stage of multifluid geo-energy system well-field operations, injection-well overpressure $\Delta P$ steadily increases (Fig. 3). Because the viscosity of CO$_2$ is less than that of brine, $\Delta P$s smaller at the CO$_2$ injectors than at the brine injectors for the first ~20 yr of production. The portion of produced brine that needs to be diverted (net extraction) to achieve the target $\Delta P$ varies between 1% and 13.1% for the cases considered in this study (Table 3). The ratio of net extracted brine to total produced brine decreases with increasing $\Delta P$. For a net CO$_2$ storage rate of 120 kg/s, <5% of the produced brine needs to be diverted to achieve a target $\Delta P$. For larger net CO$_2$ storage rates, more brine must be diverted to achieve the target $\Delta P$ (Figs. 6A, 6C, and 6E). Table 4 shows the relationship between net brine extraction and net CO$_2$ storage. Relative to net CO$_2$ storage, less net brine extraction is required for smaller net CO$_2$ storage rates and larger target $\Delta P$.

The $\Delta P$ oscillations in Figure 3 are primarily related to the cyclic timing of brine reinjection and reservoir pressurization. The NUFT numerical simulator (Hao et al., 2012) was recently modified to accurately determine the amounts of produced brine and CO$_2$ that need to be reinjected into the reservoir. For calculation efficiency, we decided to determine the required values over a finite prescribed timeframe, rather than instantaneously; for this study we determined this amount on a daily basis. For 12 h, we store the produced brine in a brine staging pond (Fig. 1), and then inject that quantity of brine during the following 12 h period. This cyclic process could represent brine reinjection scheduled when power supply exceeds demand, such as at night when conditions are windy and there is surplus wind energy on the electric grid.

For calculation efficiency we also have to store 12 h of CO$_2$ production, which is injected during the following 12 h period, resulting in $\Delta P$ oscillations at the CO$_2$ injectors (Fig. 3). While it may be unlikely that produced CO$_2$ would be stored in large above-ground tanks, CO$_2$ production could be varied to respond to varying power supply and demand mismatches on the electric grid. The effect of cyclic CO$_2$ production would be the same as that of cyclic CO$_2$ above-ground storage and injection, so Figure 3 represents cyclically varying CO$_2$ production to match power demand. Although $\Delta P$ oscillations occur at the injectors, fluid production rates do not oscillate (Fig. 4), because stored CO$_2$ is a cushion gas (Fig. 2). At late time, $\Delta P$ at the CO$_2$ injectors is greater than $\Delta P$ at the brine injectors and the target value of $\Delta P$ is evaluated at the CO$_2$ injectors, rather than at the brine injectors (Fig. 3).

### Reservoir Thermal Performance and Power Generation

Brine production rates increase rapidly during the initial stage of multifluid geo-energy well-field operations (Fig. 4) and peak when the target $\Delta P$ is reached (Fig. 3) and some of the produced brine is diverted for beneficial consumptive use. The decline in brine production is also related to breakthrough of CO$_2$ at the inner ring of producers. As the brine production rate falls, the CO$_2$ production rate increases so that the total fluid production rate remains nearly constant throughout the remainder of the 30 yr operating period (Fig. 4).

Temperature decline is distinctly different for the inner and outer rings of producers (Fig. 5). For the inner ring of producers, the operational goal is for CO$_2$ breakthrough to occur early so that CO$_2$ production can contribute to geothermal heat recovery. Our idealized model of lateral homogeneity will delay the simulated breakthrough of CO$_2$ at the inner ring of wells. Thus, our idealized model tends to underrepresent the early contribution of CO$_2$ to total power generation. The multiring well configuration used in our approach is designed to prevent CO$_2$ from reaching the outer ring of producers. Because only brine is produced, the outer ring is located far enough away from the ring of brine injectors to delay the breakthrough of injected brine and thereby delay thermal decline. Thus, by design, the onset of thermal decline occurs later at the outer ring of producers than at the inner ring of producers.

Figure 4 shows CO$_2$ breakthrough occurring earlier (~2 yr) for the higher net storage rate (240 kg/s) than for the lower net CO$_2$ storage rate (~4 yr) (120 kg/s). Consequently, at the inner ring of producers, the onset of thermal decline is at 2 and 4 yr for net CO$_2$ storage rates of 240 and 120 kg/s, respectively. The CO$_2$ that first reaches the inner producers has migrated along the uppermost (and coolest) portion of the permeable reservoir. Eventually, the zone over which CO$_2$ sweeps heat extends vertically deeper into the reservoir and into rock with higher temperatures. This expansion of the heat sweep zone causes the temperature at the inner producers to increase after the initial decline (Fig. 5).

### TABLE 3. RATIO OF NET BRINE EXTRACTION TO TOTAL BRINE PRODUCTION

<table>
<thead>
<tr>
<th>Net CO$_2$ storage rate</th>
<th>120 kg/s</th>
<th>240 kg/s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target overpressure</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 MPa</td>
<td>8 MPa</td>
<td>10 MPa</td>
</tr>
<tr>
<td>6 MPa</td>
<td>8 MPa</td>
<td>10 MPa</td>
</tr>
<tr>
<td>3 km depth</td>
<td>0.131</td>
<td>0.091</td>
</tr>
<tr>
<td>4 km depth</td>
<td>0.115</td>
<td>0.081</td>
</tr>
<tr>
<td>5 km depth</td>
<td>0.071</td>
<td>0.049</td>
</tr>
</tbody>
</table>
Figure 6. (A, C, E) Net CO₂ storage and net brine extraction plotted as a function of target overpressure ΔP for net CO₂ storage rates of 120 and 240 kg/s and reservoir depths of 3 km, 4 km, and 5 km. (B, D, F) The 30 yr averaged total mass flow rate of brine and CO₂ are plotted as a function of target overpressure ΔP for net CO₂ storage rates of 120 and 240 kg/s and reservoir depths of 3 km, 4 km, and 5 km.
Because the heat capacity of CO₂ is smaller than that of water, it has less of a quenching effect on reservoir temperature. As a consequence, the production temperature remains relatively high. In contrast, when injected brine reaches the outer producers, temperature decline is generally steeper at the outer ring of producers than it is at the inner producers because brine has a higher heat capacity than CO₂.

The rate of thermal decline for both the inner and outer producers increases with target ΔP (Fig. 5) because mass flow rate of brine and CO₂ increases with target ΔP (Figs. 6B, 6D, and 6F). The rate of thermal decline of the inner ring of producers increases with net CO₂ storage rate because mass flow rate of CO₂ increases with net CO₂ storage rate. Because the mass flow rate of brine increases with reservoir depth (Figs. 6B, 6D, and 6F), the rate of thermal decline at the outer ring of producers increases with depth (Fig. 5). Because the mass flow rate of CO₂ is insensitive to reservoir depth, the rate of thermal decline at the inner ring of producers is insensitive to depth.

Gross power (Figs. 7A, 7C, and 7E) increases with target ΔP in the same way that the mass flow rates of brine and CO₂ increase with target ΔP (Figs. 6B, 6D, and 6F). Net power, however, increases more slowly with target ΔP because the pumping load of brine recirculation increases with target ΔP and because the earlier thermal decline that results from greater brine mass flow rates reduces net power generation on a per well basis (Fig. 8B). The small reduction in net power generation on a per well basis (Fig. 8B) indicates that increasing the net CO₂ storage rate also reduces the efficiency of electricity generation.

The contribution of CO₂ as a geothermal heat recovery fluid relative to that of brine depends strongly on reservoir depth. The ratio between CO₂ viscosity and brine viscosity is the primary physical property that influences how much CO₂ contributes to geothermal heat recovery. At shallower depths and lower resource temperatures, the ratio of CO₂ viscosity to brine viscosity is much smaller than it is at greater depths and resource temperatures, so that CO₂ preferentially flows to the inner-ring production wells. While the mass flow rate of CO₂ decreases somewhat with increasing reservoir depth, the mass flow rate of brine increases with depth (Figs. 6B, 6D, and 6F) because brine viscosity decreases more strongly with increasing temperature than does CO₂ viscosity. As a result, the relative contribution of CO₂ to geothermal heat recovery decreases with increasing reservoir depth (Fig. 8C). The relative contribution of CO₂ to geothermal heat recovery increases with net CO₂ storage rate because CO₂ breakthrough occurs earlier at the inner-ring production wells.

**LCOE and Value of CO₂ to Power Generation**

The LCOE decreases with increasing reservoir depth and resource temperature (Figs. 7B, 7D, and 7F). The two primary economic factors contributing to this relationship are (1) net power generated on a per production well basis (Fig. 8B) increases strongly with reservoir depth and temperature; and (2) power plant cost ($/net kW) decreases with reservoir depth and temperature (Table 2).

Although the well development cost for a reservoir depth of 5 km (~$12.3 million/well) is twice that of a reservoir depth of 3 km (~$6 million/well), the net power generated on a per well basis is ~3.3-4.0x greater for a reservoir depth of 5 km than it is for a depth of 3 km. Power plant cost for a reservoir depth of 3 km (~$3200/net kW) is ~1.8x greater than it is for a depth of 5 km (~$1750/net kW).

The difference in LCOE between the 5 and 4 km reservoir depth cases is less than between 5 and 3 km. Well development cost for a reservoir depth of 5 km is ~1.6x greater than it is for a reservoir depth of 4 km (~$7.8 million/well), but the net power generation on a per production well basis is only 1.6-1.7x greater. Differences in power plant costs are the primary reason for the difference in LCOE between these reservoir depths: ~$2690/net kW for a reservoir depth of 4 km versus ~$1750/net kW for a depth of 5 km.

Practically, usable reservoir depths will also be determined by the geology at a given site. However, in many sedimentary basins, such as the Williston Basin in North Dakota (USA), multiple overlying reservoir caprock units exist at various depths, so that a choice of the reservoir to be used may exist, pending other factors and considerations, for example, caprock integrity.

As discussed in the techno-economic methodology section, the average per well mass flow rate is assumed to be the same for all cases. Because the mass flow rate of CO₂ and brine increases with target ΔP and net CO₂ storage rate, the required number of producers increases accordingly (Fig. 8A and Table 2). As a result, fixed costs (e.g., during the permitting and the exploration phase) will be relatively less, compared to total project costs, for cases with a larger number of producers. Net power per production well decreases with increasing mass flow rate (Fig. 8B) because the rate of thermal decline increases with mass flow rate. This decrease more than offsets the economy of scale benefit of larger overall mass flow rate.

LCOE was also determined for brownfield cases that utilize injectors and producers from a previous operation, such as a depleted oilfield (Figs. 7B, 7D, and 7F; Table 2). The difference between the greenfield and brownfield LCOE values quantifies the contribution of well-development costs to total project costs. Table 5 lists the ratio of well-development cost to total project cost. For all cases considered in this study, at least 50% of project costs are related to well-development cost. Therefore, if horizontal production wells can produce mass flow rates >>120 kg/s, the LCOE could decrease, depending on the additional cost associated with drilling the horizontal leg of those wells.
Figure 7. (A, C, E) Gross and net power plotted as a function of target overpressure $\Delta P$ for net CO$_2$ storage rates of 120 and 240 kg/s and reservoir depths of 3 km, 4 km, and 5 km. (B, D, F) Levelized cost of electricity (LCOE, in U.S. cents) plotted as a function of target $\Delta P$ for net CO$_2$ storage rates of 120 and 240 kg/s and reservoir depths of 3 km, 4 km, and 5 km.
To monetize the value of net CO₂ storage to power generation, the unit CO₂ value was determined assuming 30 yr of power sales at 10 ¢/kWh (¢ is U.S. cents; Fig. 8D). Unit CO₂ value is defined as the power sales per tonne of CO₂ and increases modestly with target ΔP, which may offset the increase in LCOE with target ΔP. Doubling the net CO₂ storage rate from 120 to 240 kg/s reduces unit CO₂ value almost by half. Therefore, from a CO₂ utilization perspective, smaller net CO₂ storage rates may be more viable. Thus, it may be commercially advantageous to deliver captured CO₂ from a given fossil-energy plant to multiple modules of multiring, multifluid geo-energy systems. Finding a site with sufficiently high resource temperature is also important; it therefore may be advantageous to transport the captured CO₂ a greater distance in order to utilize a sufficiently hot resource. Another strategy to increase unit CO₂ value would be to include thermal energy storage in a portion of the concentric-ring well-field operation, in a manner similar to that discussed in Buscheck et al. (2014b).

For pressurized oxy-fuel combustion power plants, a source of essentially free N₂ would be available from the air separation unit. Including N₂ as a supplemental fluid could also substantially increase unit CO₂ value. Another strategy to increase unit CO₂ value is to include bulk energy storage (BES), as discussed in the following.

**Bulk Energy Storage**

For the previous analyses, we assumed that the pumping loads associated with pressurizing and reinjecting brine and CO₂ are synchronous with gross power generation throughout the 30 yr operation period. Here we consider asynchronous pumping loading conducted on a diurnal basis for the purpose of BES. For asynchronous pumping loading, we categorize geothermal energy system operations into two time periods.
The recharge period is when the pumping load of brine pressurization and injection is entirely imposed on the fluid recirculation system. During this period, the heat withdrawal rate from the reservoir can also be reduced to achieve negative net power generation, which corresponds to taking (storing) energy from the electricity grid.

The discharge period is when only the minor pumping loads (e.g., pressurizing and injecting CO₂) are imposed. During this period, net power is nearly equal to gross power and energy stored during the recharge period is returned to the electricity grid. Net power ratio is defined to be net power during the discharge period, divided by constant (or average) net power that would occur with synchronous pumping loading and a constant geothermal heat withdrawal rate.

We considered a diurnal BES cycle consisting of a 6 h recharge period and an 18 h discharge period. Two specific cases are included: (1) BES case A, which time shifts the brine pumping load for a 6/18 h recharge/discharge cycle and (2) BES case B, which is almost the same as case A, but reduces the geothermal heat withdrawal rate by 50% during recharge (Fig. 9). Only one case with constant heat withdrawal (BES case A; Fig. 9B) yields a negative net power during recharge, corresponding to taking (storing) energy from the grid. When variable heat withdrawal is added, all six cases yield negative net power during recharge, resulting in significant grid-scale BES.

Two sets of distinctly different cases are considered. For cases with a target ΔP of 6 MPa (Figs. 9A, 9C, and 9E), the pumping load to pressurize and reinject brine is relatively small. For cases with a target ΔP of 10 MPa (Figs. 9B, 9D, and 9F), this pumping load is larger. Furthermore, the second set of cases has greater values of gross power than the first set of cases. The net power ratios for these cases are listed in Table 6.

The net power ratio increases with decreasing depth and temperature because the pumping load is relatively larger at shallower reservoir depth and lower resource temperature. The net power ratio is larger for BES case B than for BES case A. Net power ratio also increases with target ΔP. For BES case B and a target ΔP of 10 MPa, at least 200 MW (Figs. 9B, 9D, and 9F) is taken from the grid during the recharge period and, during the discharge period, net power is 52–100% greater than it would be for synchronous pumping loading (Table 6). Thus, the geothermal resource generates more electricity when the price of electricity is higher, while taking electricity from the grid (e.g., at night) when the price of electricity is lower. Thus, electricity arbitrage can add substantial economic value to a geothermal resource.

We did not assess the direct costs of our approach for implementing BES, but because our approach achieves this storage by simply time shifting a pumping load already required to circulate the working fluids for geothermal heat recovery, the direct costs are only those associated with oversizing the pumps required to inject brine. If additional energy storage is achieved by varying the geothermal heat withdrawal rate, then the other direct cost is that of oversizing the Brayton cycle CO₂ turbines and heat exchangers that transfer enthalpy from the produced brine to the produced and surface-recirculated CO₂. Compared to the costs of existing energy storage technologies (e.g., grid-scale batteries), such costs may be substantially less.

The geothermal energy recovery efficiency of our approach is not reduced by asynchronous pumping loading, compared to synchronous pumping loading. The efficiency of our approach is insensitive to whether variable geothermal heat withdrawal is used. Therefore, our approach does not waste a portion of the energy that is being stored, unlike most energy storage technologies (e.g., PSH). Because our approach uses the vast subsurface, its storage capacity is likely to be much greater than most other technologies. Moreover, our approach has very little surface footprint, compared to other technologies, such as PSH.

The added benefit of multifluid BES can enhance the financial viability of what may otherwise be a marginal geothermal resource, while simultaneously promoting the increased use of variable renewable energy sources, such as wind and solar. An important goal for future work is to include the economic benefit of BES in monetizing the value of net CO₂ storage. Because stored CO₂ functions as a cushion gas, BES capacity, both with regard to storage rate and storage duration, increases with stored CO₂ mass; so, CO₂ effectively performs the function of a battery, potentially making it a highly valuable commodity. Relative to material costs associated with grid-scale battery technology, the cost of capturing CO₂ from fossil-energy systems may actually be significantly less.

### CONCLUSIONS

Addressing the challenge of reducing CO₂ emissions requires technology advances that enable viable, widespread deployment of geological CO₂ storage (GCS) and grid-scale energy storage that accommodates greatly increased use of variable renewable energy sources. We present a synergistic approach designed to address these challenges by enabling (1) geothermal energy production in widely distributed geologic settings (sedimentary basins) where conventional geothermal energy systems are not viable, and (2) grid-scale energy storage at a potentially greatly reduced cost, compared to existing technologies.

Our approach is designed to address three key barriers to widespread deployment of GCS. By creating valuable uses for captured CO₂, our approach addresses an enormous deployment barrier, i.e., the cost of capturing CO₂. Our approach also addresses another major barrier for industrial-scale deployment of GCS, i.e., overpressure created by that storage. Because our approach provides a source of water, it also addresses the challenge of the water intensity of CO₂ capture.
Figure 9. Net power over a 48 h period is plotted 10 yr into the operating life for the case of no bulk energy storage (BES), BES case A that time shifts the load of brine pumping to a 6 h recharge period, and BES case B that applies the time shifting of case A and reduces gross power by half during the 6 h recharge period. Net CO₂ storage rate is 120 kg/s for all cases, which includes reservoir depths of 3 km, 4 km, and 5 km, and two values of target over-pressure \( \Delta P \), 6 MPa and 10 MPa.
TABLE 6. NET POWER RATIO

<table>
<thead>
<tr>
<th>Reservoir depth</th>
<th>3 km</th>
<th>4 km</th>
<th>5 km</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target overpressure</td>
<td>6 MPa</td>
<td>10 MPa</td>
<td>6 MPa</td>
</tr>
<tr>
<td>Bulk energy storage case A</td>
<td>1.31</td>
<td>1.50</td>
<td>1.14</td>
</tr>
<tr>
<td>Bulk energy storage case B</td>
<td>1.74</td>
<td>2.00</td>
<td>1.52</td>
</tr>
</tbody>
</table>

The multiscale geo-energy approach uses a problem created by GCS (over-pressure) and turns it into a solution to efficiently produce and store energy, while generating water. A minimum of four rings of concentric injection and production wells are used to contain supplemental fluid (CO₂ and/or N₂) and pressure, drive native brine to production wells, and release that pressure, supplemental fluid, and brine when the demand for electricity exceeds the supply. We utilize a reservoir pressure management strategy that diverts a portion of the produced brine, once a target overpressure is reached at the injection wells. This diverted brine is available for beneficial consumptive use, such as for power plant cooling, or it can be used to generate fresh water, either using reverse osmosis or flash distillation. The added benefit of water generation can be particularly valuable in regions of water scarcity. We find that only a small portion (<5% unless CO₂ is stored at a very high rate) of the produced brine needs to be diverted for the injection wells to remain below the target overpressure.

In addition to being a very efficient geothermal working fluid, stored CO₂ also functions as a cushion gas that enables the storage of pressure and energy. Because our approach circulates the geothermal heat recovery fluids with stored pressure, it can be used for energy storage by time-shifting pressurization and recharge of the system. Our system can also provide dispatchable electricity to quickly respond to supply and demand mismatches, by varying the timing of when pressure is released from the production wells and geothermal heat withdrawal is allowed to occur. We find that time shifting the pumping load of pressurizing and reinjecting brine does not reduce the geothermal energy recovery efficiency of our system, so it is inherently more efficient than other energy-storage approaches. Because the vast subsurface is used for storage, it also has much greater storage capacity, as well as a smaller surface footprint, than other energy storage technologies. Electricity arbitrage that may be enabled by our approach has the potential of adding substantial economic value to both a geothermal resource and the CO₂ that is stored within it.

The reservoir model used in our study assumed a homogeneously porous and permeable reservoir, with homogeneous caprock and bedrock sealing units, and a simplified representation of the displacement of resident brine by injected CO₂. Heterogeneity within the reservoir should produce preferential flow paths for injected fluids that would hasten breakthrough and affect heat extraction. Similarly, the simplified physics of the immiscible displacement of native brine in our model neglects viscous or capillary fingering. This fingering is a nonuniform displacement of brine that would result in the coproduction of CO₂ and brine or injected brine and native brine earlier in time than in our results, and this coproduction of fluid mixtures would persist. Future reservoir modeling studies could relax the assumptions of homogeneity within the reservoir and within the sealing units, as well as incorporate fingering processes in order to investigate these phenomena and estimate their effects on managed pressures, thermal plumes, and heat extraction.

A techno-economic assessment of our approach shows that the LCOE is potentially competitive with other renewable energy technologies, and further study could investigate the sensitivity of the estimated LCOE to assumptions of homogeneity and perfect immiscible displacement of native brine by injected fluids. Future work that assesses the economic benefit of energy storage enabled by our approach may show that it increases the economic viability of our system, while broadening its geographic deployment potential.

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DISCLAIMER

J.B. Randolph and M.O. Saar have significant financial and business interests in TerraCOH Inc., 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 TerraCOH Inc. These relationships have been reviewed and managed by the University of Minnesota in accordance with its conflict of interest policies.

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