ENHANCED GEOTHERMAL SYSTEMS (EGS): COMPARING WATER AND CO_2 AS HEAT TRANSMISSION FLUIDS

Karsten Pruess

Lawrence Berkeley National Laboratory, Berkeley, CA 94720, USA

K_Pruess@lbl.gov

Abstract

It has been suggested that enhanced geothermal systems (EGS; also referred to as "hot dry rock" systems) may be operated with supercritical CO_2 instead of water as heat transmission fluid (D.W. Brown, 2000). Such a scheme could combine recovery of geothermal energy with simultaneous geologic storage of CO_2, a greenhouse gas. At geothermal temperature and pressure conditions of interest, the flow and heat transfer behavior of CO_2 would be considerably different from water, and chemical interactions between CO_2 and reservoir rocks would also be quite different from aqueous fluids.

This paper summarizes our research to date into operating EGS with CO_2. Our modeling studies indicate that CO_2 would achieve more favorable heat extraction than aqueous fluids. The peculiar thermophysical properties of CO_2 give rise to unusual features in the dependence of energy recovery on thermodynamic conditions and time. Preliminary geochemical studies suggest that CO_2 may avoid unfavorable rock-fluid interactions that have been encountered in water-based systems. To more fully evaluate the potential of EGS with CO_2 will require an integrated research programme of model development, and laboratory and field studies.

1. Introduction

Geothermal energy extraction is currently limited to the highest grade "hydrothermal" resources with reservoir permeability and fluid reserves sufficiently large to sustain production at commercial rates. Efforts to tap into the much larger resource base of hot rocks with insufficient permeability and/or fluid supply have been made and are ongoing in several countries, but so far have met with only limited success. Commercial development of so-called "enhanced" (or

"engineered") geothermal systems (EGS) faces significant technical and economic hurdles, among them (1) the difficulty of stimulating natural or generating artificial fractures in a sufficiently large volume of hot rock, of order 1 km^3; (2) achieving and maintaining fluid circulation at commercial rates and avoiding the twin obstacles of (a) insufficient permeability of the fracture network, and (b) short-circuiting pathways that would lead to premature thermal breakthrough at production wells.

Earlier research on EGS, often referred to as "hot dry rock" (HDR), had emphasized the coupling of hydraulic and thermal effects to rock mechanics - the opening and closing of fractures in response to changing stresses. More recently it has become clear that chemical interactions between rocks and fluids can play a large role in EGS reservoir development and operation (Durst, 2002; Bächler, 2003; Xu and Pruess, 2004; Rabemanana et al., 2005; André et al., 2006). Water is a powerful solvent for rock minerals at elevated temperatures, and artificially induced water circulation may induce strong dissolution and precipitation effects. This can lead to formation plugging or may promote short-circuiting pathways. Unavoidable fluid losses during operation of an EGS reservoir also present problems, especially in water-short regions such as the southwestern U.S.

This paper reviews recent research into the novel concept of using supercritical CO_2 instead of water as heat transmission fluid for EGS (Brown, 2000). Operating EGS with CO_2 could avoid many of the problems of water-based systems, while offering geologic storage of CO_2, a greenhouse gas, as ancillary benefit. As pointed out by Brown (2000) and Fouillac et al. (2004), CO_2 is not an ionic solvent, and would be a poor solvent for rock minerals, thus eliminating scaling problems. Brown also noted as an unfavorable property the lower mass heat capacity of CO_2 in comparison to water, but pointed out that this would be partially compensated by the greater flow capacity of CO_2 due to its lower viscosity. The much larger thermal expansivity of CO_2 would generate large density differences between the cold CO_2 in the injection well and the hot CO_2 in the production well, and would provide buoyancy force that would reduce the power consumption of the fluid circulation system.

Only recently have efforts begun to develop a more specific, quantitative understanding of potential advantages and disadvantages of operating EGS with CO_2. This paper discusses recent advances and highlights open issues in assessing the potential of EGS-CO_2 technology.

2. EGS Reservoir Development

For water-based systems, the essential step in EGS reservoir development involves stimulation, chiefly by hydraulic and chemical means, to improve permeability of the target formations. In order to be able to operate EGS with CO_2, stimulation would be followed by an additional step of reservoir development, in which CO_2 would be injected over a period of time to displace and essentially remove the resident water, at least from the central zone of the stimulated volume. Produced fluids during this development phase would initially be a single aqueous phase, followed by two-phase flow of water-CO_2 mixtures. Over time the water content of produced fluid would decrease, and eventually dry, anhydrous CO_2 would be produced. After some period of CO_2 injection, water would be completely removed from the core of the system, first by immiscible displacement, and later by dissolution (or evaporation) of resident immobile water into the flowing CO_2 stream. No quantitative analyses of this process have been published yet, as flow simulation capabilities that accurately describe the partitioning of water and CO_2 between aqueous and CO_2-rich phases for the entire range of relevant temperature and pressure conditions are not currently available.

The development of an EGS-CO_2 reservoir is expected to produce three distinct zones (Fouillac et al., 2004; Ueda et al., 2005), (1) an inner (or core) zone in which water has been completely removed by flowing CO_2, so that the reservoir fluid would be dry supercritical CO_2, (2) a surrounding zone with two-phase water-CO_2 mixtures, and (3) a peripheral or outer zone in single-phase aqueous conditions with some dissolved CO_2. Chemical interactions between reservoir fluids and rocks are expected to be quite different in these different zones. Rock-fluid interactions in zones 2 and 3 would be mediated by the aqueous phase. Some information on relevant processes is available from natural CO_2-bearing geothermal systems (Giolito et al., 2007), laboratory experiments (Ueda et al., 2005), and reactive chemical transport modeling (André et al., 2007). The Bagnore and Piancastagnaio geothermal fields at Monte Amiata, Italy, have CO_2-rich fluids with up to 15 wt.-% gas content in produced steam, and display unusual

mineral composition (Giolito et al., 2007). Ca-Al-silicates commonly encountered at temperatures of 250-350 ^{o}C are absent or rare, and vein deposits include abundant carbonates (calcite, ankerite, dolomite and siderite). These observations are suggestive of the kinds of mineral transformations that may be induced in the outer zones of man-made EGS with CO_2. Ueda et al. (2005) performed laboratory experiments in which they exposed granodiorite from the Ogachi, Japan, hot dry rock field to aqueous solutions of CO_2 at temperatures of 200 ^{o}C. They noted that over a period of 15 days, significant amounts of calcium were released from minerals such as plagioclase and anorthite, and were precipitated as carbonates. Modeling studies by André et al. (2007) for the carbonate-rich Dogger aquifer, France, suggested that at the prevailing temperature of 75 ^{o}C carbonates are highly reactive and readily dissolve in response to CO_2 injection, giving rise to increased reservoir porosity. Chemical reactivity between dry (anhydrous) supercritical CO_2 and common rock minerals is expected to be low in most cases, but research on reactions between supercritical CO_2 and rocks in the absence of water has started only recently (Regnault et al., 2005; Jacquemet, 2006). As aqueous phase saturations are reduced during continuous CO_2 injection, it is expected that eventually saturation limits will be exceeded for several minerals in the residual aqueous phase, so that some porosity decrease would occur during the dry-out process (André et al., 2007).

3. Reservoir Heat Extraction

In practical field situations, an EGS reservoir operating with CO_2 is likely to continue to produce some water along with CO_2, although the concentration of water in the production stream may be sufficiently small to enable all water to remain dissolved in the supercritical CO_2. We have studied the performance of CO_2 as a heat transmission fluid for a range of temperature and pressure conditions, ignoring effects from admixtures of water vapor or other gases, and have made comparisons with water as a transport medium for thermal energy. For a given effective pressure gradient, fluid mass flow rate is proportional to the mobility m = ρ/μ (ρ = fluid density, μ = viscosity), which for CO_2 has a very different dependence on temperature and pressure conditions than for water (Fig. 1). For most T,P-conditions, CO_2 is considerably more mobile than water, so that, for a given pressure gradient, it would flow at larger mass rates than water. Detailed numerical simulations have shown that this effect more than compensates for the smaller specific heat of CO_2, and produces larger heat extraction rates for CO_2 than for water.

Advantages of CO_2 as heat transmission fluid show significant dependence on temperature and pressure conditions (Pruess, 2006, 2007).
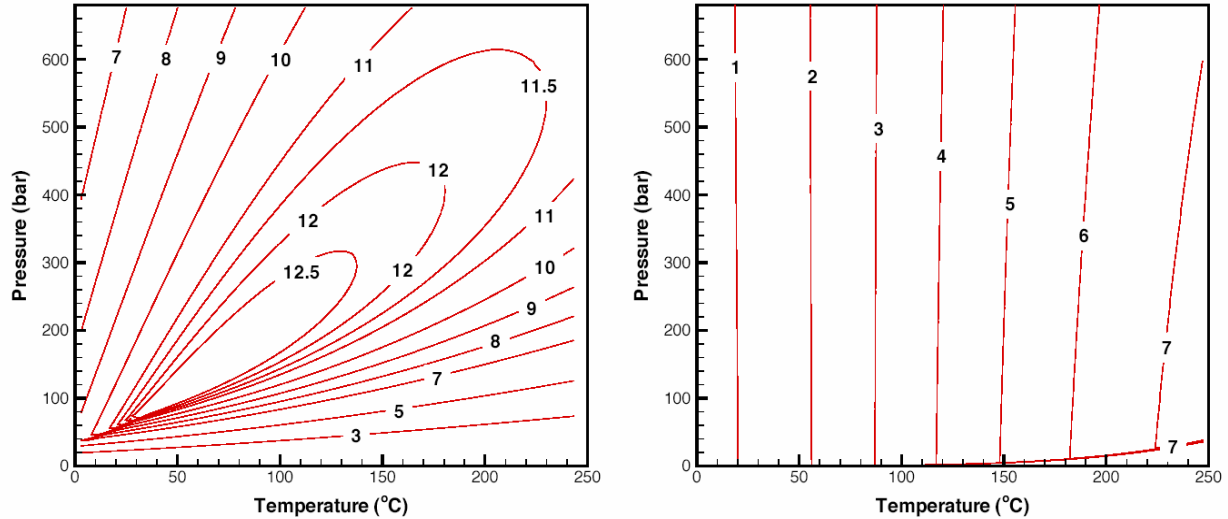

Figure 1. Fluid mobility (ratio of density to viscosity) in units of 10^6 sm^{-2} for CO_2 (left) and water (right) (from Pruess, 2006).

Numerical simulations were performed for a hypothetical fractured reservoir with parameters patterned after the European EGS experiment at Soultz/France. Fluid circulation is induced by specifying a certain pressure drop, typically assumed to be 20 bar, between the injection and production sides of the reservoir, and monitoring and comparing mass flow and heat transport for an "all CO_2" and an "all water" system. The simulations were performed with our general-purpose simulator TOUGH2 (Pruess, 2004), augmented with a special fluid property module "ECO2N" to provide fluid properties for CO_2 and water (Pruess and Spycher, 2007). (ECO2N has an upper temperature limit of 110 ^{o}C, which is primarily due to the non-iterative model for partitioning of CO_2 and water between aqueous and CO_2-rich phases. For systems of either pure CO_2 or pure water, as studied here, this temperature limit can be removed.)

Results for a five-spot injection-production system (Fig. 2) with initial conditions of (T, P) = (200 ^{o}C, 500 bar) and a fluid injection temperature of 20 ^{o}C are given in Fig. 3 (Pruess, 2006). It is seen that heat extraction rates are approximately 50 % larger with CO_2 initially than
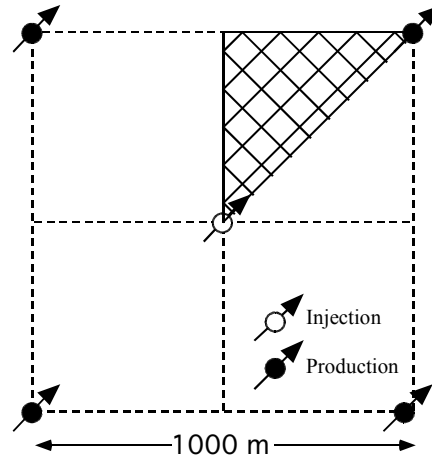
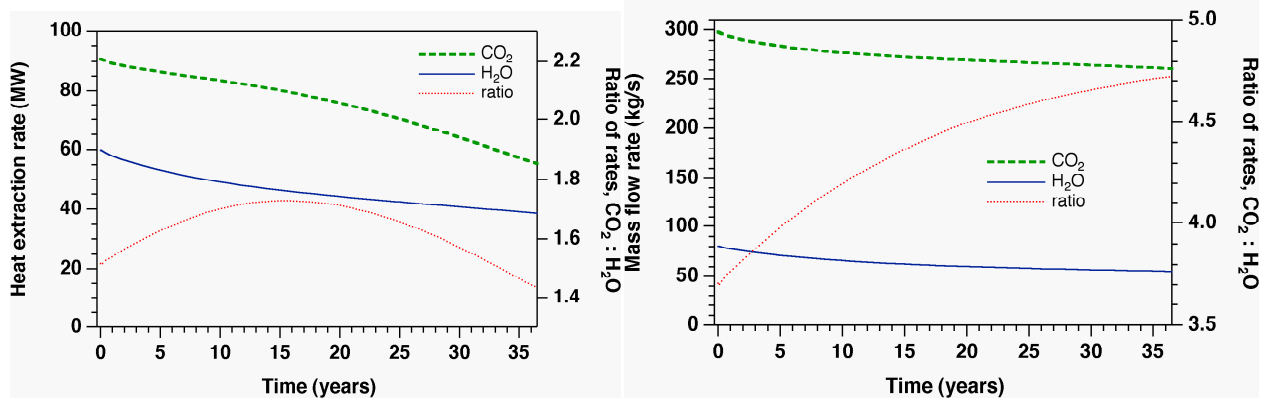Figure 2. Five-spot well pattern with computational grid for modeling a 1/8 symmetry domain.

Fig. 3. Rate of net heat extraction (left) and mass flow rates (right) for the five-spot fractured reservoir problem (full well basis). The ratios of the rates for the CO_2 and water systems are also shown.

with water. The difference becomes smaller with time, due to the more rapid thermal depletion when using CO_2. Mass flow rates in the CO_2 system are larger than for water by factors ranging from 3.5 to almost 5. These results show that mass flow increase due to the much lower viscosity of CO_2 more than compensates for the smaller density and specific heat of CO_2. Fig. 4 shows pressures and temperatures after 25 years of fluid circulation along a line connecting injection and production wells. It is seen that for CO_2 the pressure profile is almost symmetrical between injector and producer, while for water there is a much steeper pressure gradient near the injection
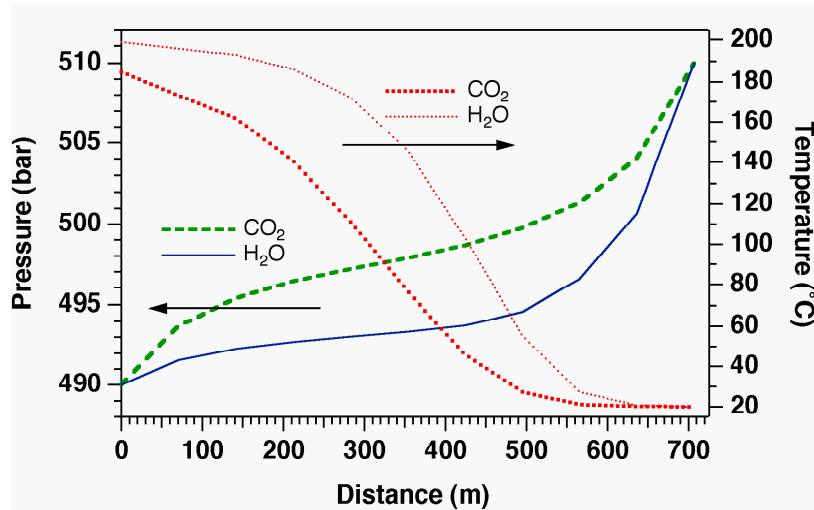
Figure 4. Pressure and temperature profiles along a line from production (distance = 0) to injection well (distance = 707 m) after a simulation time of 25 years.

well. This is explained by the strong increase in water viscosity with decreasing temperature, which causes much of the pressure drop available for pushing fluid from the injector to the producer to be used up in the cold region near the injector. In contrast, CO_2 viscosity does not change much with temperature.

Additional simulations not shown here have indicated that the relative advantage of CO_2 over water as heat transmission fluid becomes larger for decreasing reservoir temperature. This again is an effect of the strong increase of water viscosity with decreasing temperature.

An earlier comparison of heat extraction for CO_2 and water-based systems had considered a linear flow system rather than a five-spot, and had found only a modestly larger heat extraction rate for CO_2 as compared to water (approximately 15 % larger; Pruess and Azaroual, 2006). The large differences in relative heat extraction rates between the linear system and the five-spot seems surprising, in view of the fact that the thermodynamic conditions for the reservoir and the injected fluid were the same in both problems. However, the differences can be understood from the different flow geometries, that are differently affected by the large increase in water viscosity near the injection point. Indeed, the radial flow geometry around the injection

well in the five-spot problem amplifies the "mobility block" for water and the associated enhancement in pressure gradient, as compared to the linear flow geometry in the linear system.

4. 3-D Flow Effects

Density differences between cold fluid in and around the injection well and hot reservoir fluid are much larger for CO_2 than for water. This gives rise to two related 3-D effects in EGS operated with CO_2, (1) for an injection well with a sizeable open interval, the large "cold" pressure gradient will cause outflow rates per unit reservoir thickness to increase with depth, and (2) cold injected fluid will be subject to negative buoyancy in the reservoir, and will tend to slump downward. If both injection and production are made over the same depth interval, these effects will promote rapid thermal breakthrough near the bottom of the permeable interval. These effects are apparent in Fig. 5, which shows production flow rates and temperatures for a 3-D version of the five-spot problem discussed above, in which the reservoir thickness of 305 m was divided into 6 layers, and fluid injection and production were made over the entire open interval (Pruess, 2007). Premature breakthrough of cold injected fluid can be avoided by restricting production to a shallower depth interval. Producing from shallower horizons than where injection is made provides safeguards against short-circuiting flow of cold injected fluid, as such fluid will slump downward in the reservoir, and will not be able to reach the production well through a direct path.
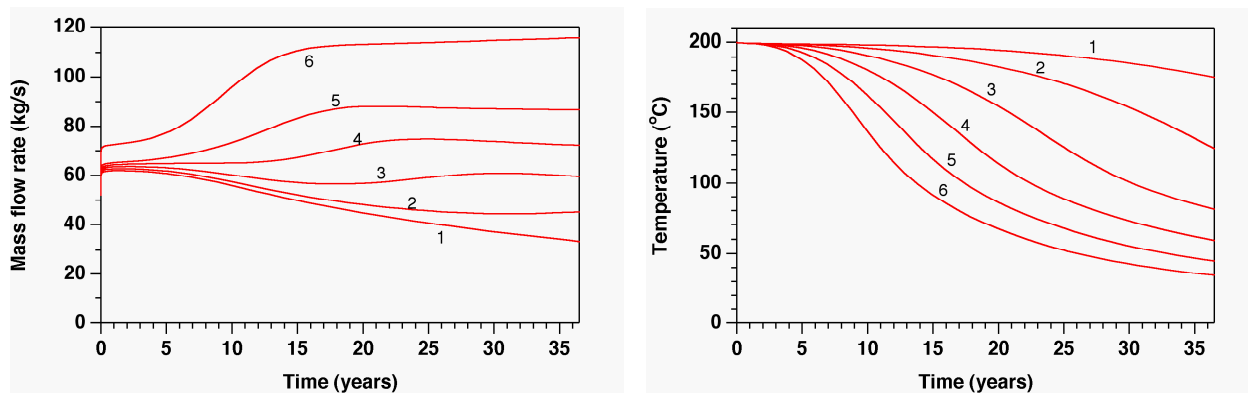

Figure 5. Production rates (left) and temperatures (right) in the different reservoir layers (1 - top, 6 - bottom) for a CO_2-EGS with injection and production wells open in all layers.

5. CO₂ Storage

Long-term EGS water circulation tests carried out over periods of months to almost one year suggest that long-term fluid losses may amount to approximately 5 % of injection (Duchane, 1993). Applying appropriate correction factors for thermodynamic and utilization efficiency, we estimate that for the reference case reported above, a mass flow of approximately 22 kg/s of CO_2 will be required per MW electric power (Pruess, 2006). At an estimated 5 % fluid loss rate, CO_2 loss will then be approximately 1 kg/s per MWe, or 1 tonne/s per 1,000 MWe. For a perspective on this number, we note that a 1,000 MWe coal-fired power plant generates approximately 1/3 tonne/s of CO_2 (Hitchon, 1996). These figures suggest that 1,000 MWe of EGS-CO_2 could achieve geologic storage of the CO_2 emitted from 3,000 MWe of coal-fired generation. While these estimates are very rough, they suggest a very large potential for CO_2 storage from EGS with CO_2.

The estimates presented here assume that CO_2 lost equals CO_2 stored. This assumption will of course require thorough scrutiny before practical implementation of EGS with CO_2 could be considered. The assumption may appear very optimistic, but seems quite realistic in our view because escaping CO_2 would react rapidly with formation minerals in the aqueous high-temperature environments surrounding an EGS reservoir (Fouillac et al., 2004).

6. Wellbore Hydraulics

Pressure gradients in flowing wells arise from gravitational, frictional, and acceleration effects. The latter two will typically amount to no more than a few percent of the gravitational gradient, and may be neglected for a first assessment of effects. Fig. 6 compares static pressure profiles in water and CO_2 injection and production wells. For both water and CO_2, injection wellhead conditions are assumed as (T, P) = (20 $^{\circ}$C, 57.4 bar). This wellhead pressure was chosen because it is slightly larger than the CO_2 saturation pressure, so that CO_2 may be injected as a single sub-critical liquid phase. Integrating downward, the corresponding static downhole pressures at 5,000 m depth are then found to be 528.7 bar for CO_2 and 553.4 bar for water (Fig. 4). Using these downhole pressures as starting values, we calculate static pressures in the production well by integrating upwards at T = 200 $^{\circ}$C. This results in production wellhead pressures of 288.1 bar for CO_2 and 118.6 bar for water. The difference in wellhead pressures
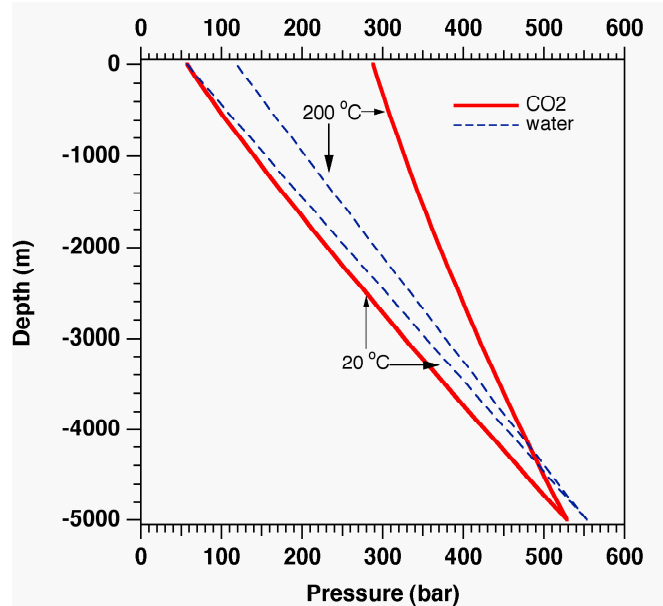
Figure 6. Static pressure profiles in CO_2 and water wells for constant temperatures of 20 and 200 ^{o}C, respectively (from Pruess, 2006).

between production and injection wells is 230.7 bar for CO_2 and 61.2 bar for water, indicating that a CO_2 circulation system would have far stronger buoyant drive. This would reduce the parasitic power consumption of the fluid circulation system, and may in fact obviate the need for pumps to keep fluid circulation going.

A more realistic outlook on longer-term P,T-conditions in flowing injection and production wells can be obtained by approximating fluid flow in the wellbore as isenthalpic rather than as isothermal. The isenthalpic flow approximation accounts for temperature changes that arise from (de-)compression of fluids, the so-called Joule-Thomson effect (Katz and Lee, 1990). For single-phase water these effects are negligibly small, but for CO_2 there is a sizeable temperature increase during compression, and a temperature decline during expansion. Accordingly, CO_2 flowing downward in the injection well will get warmer, while CO_2 flowing upward in the production well will cool. These effects will reduce density and pressure differences between injection and production fluids. However, for temperature and pressure conditions as shown in Fig. 6, the associated temperature effects are of order 10 - 20 ^{o}C or less (Pruess, 2006), so that impacts on wellbore pressures will be minor.

7. Concluding Remarks

Quantitative assessment of the potential for operating EGS with CO_2 instead of water is in the early stages. Studies to date suggest that EGS operated with CO_2 may have significant advantages over water-based systems, including larger heat extraction rates, and more favorable wellbore hydraulics. It is expected that rock-fluid interactions may also be more favorable for EGS with CO_2 than with water, but little information is available about chemical interactions between supercritical CO_2 and rock minerals. EGS with CO_2 has sufficiently attractive features to warrant continued exploration, and interest in this concept is growing (Merkel, 2006; Azaroual et al., 2007). For a realistic assessment it will be necessary to go beyond theoretical estimations and paper studies, and begin to design, implement, and analyze practical tests in the field.

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