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Fully Coupled Wellbore-Reservoir Simulation of supercritical CO₂ Injection from Fossil fuel power plant for Heat Mining from Geothermal Reservoirs

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Abstract

The concept of injecting supercritical CO₂ (sCO₂) into a geothermal reservoir was computationally investigated to obtain an insight into the performance of such system in terms of the benefit of using CO₂ captured from fossil fuel power plants for geothermal heat mining. A fully coupled wellbore-reservoir system was simulated considering the flow of pure sCO₂ in an injection well, interaction of sCO₂ and water in a permeable reservoir, initially filled with water, and the flow of the two-phase mixture of sCO₂ and water in a production well. A base case simulation was performed. Results of this simulation indicate that this CO₂ application is capable of providing a good source of renewable energy. It was found that for the reservoir section used in this study (0.08 km³) about 8-9 MW_{th} could be extracted from the geothermal resource in a steady state fashion, for a lifetime of the wells of 30 years. This is approximately equivalent to 100 MW_{th}/km³. A sensitivity analysis of the coupled wellbore-reservoir system provided information on the impact of certain parameters on the performance of the integrated system. Mass flow rate and temperature of injected CO₂, and reservoir permeability have a first order impact on the pressure management of the reservoir and the amount of heat mining from the CO₂-based geothermal reservoir. Additionally, CO₂ injection temperature has a large effect on the thermosiphon characteristic of this type of systems.

33

34Keywords: *Supercritical carbon dioxide, geothermal heat mining, Mexico*

35*geothermal power generation.*

36

37**1. Introduction**

38The increased concern with rising atmospheric carbon dioxide (CO₂), primarily from
39anthropogenic fossil fuel combustion, has motivated research and development of
40alternatives to reduce CO₂ emissions from power and industrial plants. CO₂ capture
41and sequestration in deep saline aquifers has been considered in a series of studies
42as a means for controlling this major greenhouse gas. One of the options considers
43injection of supercritical carbon dioxide (sCO₂) as a working fluid in a naturally high-
44permeability hydrothermal reservoir [1-4]. In addition to the benefit of sequestering
45CO₂ in the reservoir, sCO₂ can be used to mine geothermal energy for utilization
46above the ground. sCO₂, despite having a smaller mass heat capacity than water;
47under typical geothermal formation underground conditions, has on average 40% of
48the viscosity of water and a lower density than water. With those properties,
49injection of sCO₂ would result in an increased mass flow rate across an equivalent
50geologic reservoir and, additionally, an augmented buoyancy drive. The injected
51sCO₂ would form a large subsurface CO₂ plume that would permanently sequester
52CO₂ underground and also absorb heat from the geothermal reservoir for
53subsequent utilization at the surface, such as enhanced power generation. An
54artistic illustration of the concept of sCO₂ injection from fossil fuel power plant for
55heat mining from geothermal reservoirs is presented in Figure 1.

56

57

58 Figure 1: Illustration of sCO₂ Injection into a Geothermal Reservoir for Heat Mining
59 and Above-the-Ground Geothermal Energy Utilization.

60

61 This approach is of interest to Mexico, since it combines CO₂ capture and
62 sequestration, geothermal energy extraction and enhanced electric power
63 generation. The Mexican government is committed to reduce its carbon footprint
64 and it has set targets to cut national Green House Gas (GHG) emissions by 22%
65 below baseline in 2030, equivalent to an increase of emissions by 56% above 1990
66 levels. Mexico releases approximately 709 million tons of CO₂ annually into the
67 atmosphere (the world's 12th largest carbon emitter), with 30% of this inventory
68 coming from the electricity generating sector [5]. It is expected that in a future
69 CO₂-constrained world, relatively pure CO₂ would be available in large quantities
70 from Mexican fossil fuel power plant and other energy intensive industrial facilities,
71 such as chemical process facilities and cement plants. Mexico is conscious of the
72 need to grow its economy, with the associated need to expand its current power
73 generating capacity, and its electricity sector currently heavily relies on fossil
74 energy sources (approximately 75% of the total installed capacity). However,
75 meeting the forecasted future electricity demand with fossil fuels could increase
76 Mexico's CO₂ emissions by 230%. Adoption of green technologies by Mexico, such

77as solar, wind, hydro, biomass, and geothermal energy is a necessity to significantly
78mitigate the global warming impact of an increased power generation base. It is
79recognized that one of the largest renewable energy sources available to Mexico is
80geothermal energy. The IGA (International Geothermal Association) has reported
81that Mexico has estimated geothermal reserves of approximately 8,000 MW_e,
82second in the world only to Indonesia. Mexico has a total of eight geothermal power
83plants, already installed and in construction, totaling a current installed geothermal
84capacity of 953 MW_e (fourth in the world) [6]. Additionally, more than 1,000
85potential geothermal sites have been identified, with a large concentration of
86medium- and low-enthalpy reservoirs, encompassing Mexico's volcanic region [7].

87

88The concept of using CO₂ as a working fluid to recover heat from geothermal
89reservoirs has received a good deal of attention of lately. This as-yet-unproven
90concept relies on replacing water with sCO₂, which, research results have suggested
91would be a better working fluid than native reservoir water or brine for geothermal
92energy extraction [8-17]. Due to its thermofluid behavior under supercritical
93conditions, a geothermal system utilizing sCO₂ as the subsurface heat exchange
94fluid, in a naturally porous or fracture permeability-enhanced geologic formation,
95would provide improved heat extraction for low temperature geothermal resources
96at shallower subsurfaces below the bedrock. It has been suggested that CO₂-based
97geothermal systems could operate at up to 1.5 times the electricity-production
98efficiency of conventional water-based systems [19]. Additionally, the transport and
99solubility properties of sCO₂ would also help reduce contamination, scaling and
100degradation of power equipment found in steam-based geothermal systems.

101

102There is a body of literature presenting variations of the application of sCO₂ for heat
103mining from geothermal resources. The majority of these studies investigate the
104feasibility of the concept, framing the results on the impact of reservoir nature,
105properties and geometry on CO₂ plume formation within the reservoir and its
106associated heat extraction. One of these sCO₂-based concepts consists of injecting
107CO₂ into dry rock or hydrothermal (wet rock) geological formations, where the CO₂
108fracture/fill/displaces the native reservoir fluid, mines geothermal heat and is piped
109back to the surface for electricity production or other applications. Part of the
110injected CO₂ can be geologically stored. Brown first [8] presented the use of sCO₂ in

111hot dry rock reservoirs in 2000. The work by Brown was based on field testing and
112demonstrations carried out at the Fenton Hill test site in the Jemez Mountains of
113North-Central New Mexico. The study by Brown concluded that for a 500 m deep hot
114dry rock reservoir with an injection pressure of 300 bar, about 100,000 tons of CO₂
115per year could be sequestered, in addition to about 50,000 tons of CO₂ available for
116closed-loop circulation.

117

118Pruess [9, 10] presented the concept of CO₂-based Enhanced Geothermal Systems
119(EGS). In this system, sCO₂ would be injected into the hot impermeable rock;
120opening additional fractures in the reservoir and forming a region prone for CO₂
121diffusion in the reservoir. After initial formation of a two phase CO₂-water mixture in
122the reservoir, the passage of time will lead to the creation of a reservoir of pure
123sCO₂, circulating in closed-loop, while extracting heat and sequestering some CO₂ in
124the surrounding rock mass. In the simulations performed by Pruess [9], a reservoir
125thickness of 305 m was used, with reservoir rock temperature of 200°C, injection
126temperature of 20°C, fracture spacing of 50 m, permeable volume fraction 10%,
127negligible rock permeability and 50 md fracture permeability, 50% porosity in the
128permeable domain, and variable reservoir pressures. A five-spot well configuration
129was modelled, with a two-dimensional and five-point grid of 1,000 m side. All
130simulations were performed using the TOUGH2 [10] code, augmented with the
131ECO2N fluid property module. All simulations were performed under CO₂-only or
132H₂O-only systems, with no consideration to mixtures of both fluids, and maintaining
133the injection and production bottom-well pressures constant. The simulations
134performed by Pruess [11] conclude that heat extractions from EGS systems can be
13550 to 100% larger with sCO₂ than with water. The differences become smaller with
136time, due to the more rapid thermal depletion when using CO₂. Mass flow rates in
137the CO₂ system are also larger than for water by factors as high as 3.5. Additional
138data from the study by Pruess [11] of CO₂-based EGS estimate that typical fluid loss
139rates (sequestration rates) would be in the range of 5%, further suggesting about 1
140kg/sec/MW of sequestered CO₂. Further work by Spycher [12] on EGS systems
141concluded that the production of a free aqueous phase form in an EGS operated
142with CO₂ will occur only after a limited number of years. Spycher added that it is
143typical to expect a useful life of geothermal reservoirs of about 25-30 years.

144

Randolph [14] introduced the concept of CO₂-Plume Geothermal (CPG) in which CO₂ is used as the working fluid in a high-permeability, high-porosity geologic reservoir (typically hydrothermal or saline reservoirs) that is overlain by a low-permeability cap rock. The CO₂ displaces the native formation brine in the reservoir, heats up and then is ready for electricity generation at the surface. The sizes of these wet rock reservoirs are typically much larger than those of hydrofractured reservoirs. The simulations performed by Randolph and Saar [14, 15] are an extension of the work by Pruess [9] in which the same five-well arrangement and geometry was used and resolved using the TOUGH2 code with the ECO2N fluid property module. Different values of domain permeability were tried by Randolph, with an average value of 5×10^{-14} m². Other simulation parameters include a 20% domain porosity, reservoir pressure of 250 bar, and two reservoir assumed depths and corresponding temperatures of 4 km-150°C and 1 km- 100°C. Heat extraction rates estimated by Randolph for a 25-year average were of 62.6 MW for the deep reservoir and 64.1 MW for the shallow reservoir. The results for the CPG systems show that the heat extraction decreases with time as the heat is depleted and the temperature at the production wells decreases with time. The work of Randolph also compares CPG CO₂-based systems vs. CPG H₂O-based systems. Cases run at different combinations of initial reservoir pressure and temperature show that for an average 25-year reservoir lifetime, the heat extraction rates for CO₂ are between 2.3 to 3.0 times larger than for the H₂O-based cases. The corresponding heat extraction ratios of CO₂ to H₂O are in the range from 4.9 to 5.5 [14, 15].

168

Additional references have reported studies on CO₂ utilization for heat mining considering the geothermal reservoir only. Salimi and Wolf [16] presented another concept for CO₂ utilization in geothermal sites. This concept involves co-injection of CO₂ and water, to prevent drying out and over-pressurizing the reservoirs. Another advantage of this concept is related to the dissolved phase of CO₂ in water, which would avoid confinement of CO₂ to the upper part of the reservoir, decreasing leakage via the cap rock. Self-developed model results were presented that indicate that at CO₂ mole fractions below 0.10, cumulative heat extraction from such system can be as high as 1,000 TJ for 30 years, for a reservoir with dimensions of 250 m thick, 1,600 m long, mean porosity of 0.17, permeability of 21.6 mD and

initial temperature of 80°C. Buschneck et al. [17] introduced a hybrid two-stage approach to sequester CO₂ and produce geothermal energy in saline, sedimentary formations. In this concept, first brine is extracted from the reservoir to provide pressure relief for CO₂ injection; then, when CO₂ is injected and it reaches the production wells, co-produced treated brine and CO₂ become the working fluids for energy recovery. Three-dimensional model results, using the NUFT code, for reservoirs with temperatures in the 100°C range, report heat extraction rates with this approach as large as 100 MW/m², with combined production flow rates as high as 280 kg/s. A recent study presented by Zhang, et al [18], confirms that sCO₂ has good mobility and heat capacity, and it can be used as an alternative to water for heat recovery from geothermal reservoirs. In the work of Zhang, et al [18] different types of geothermal resources for China were assessed to screen reservoirs suitable for heat mining and geological storage by CO₂ injection, in terms of geological properties, heat characteristics, storage applicability, and development prospects. Reservoir simulations were conducted to analyze the heat extracting capacity and storage efficiency of CO₂ using a simple calculation method. The assessment results show that the recoverable geothermal potential by CO₂ injection in China is around 1.55x10²¹ J, using Hot Dry Rock (HDR) as the main geothermal resource contributor. The corresponding CO₂ storage capacity is up to 3.53x10¹⁴ kg with the deep saline aquifers accounting for more than 50% of total. It was concluded in this study that CO₂ injection for geothermal production is a more attractive option than pure CO₂ storage due to its higher economic benefits in spite of that many technological and economic issues still need to be solved. Finally, a study by the authors of this paper [19] reports an assessment of the feasibility of using sCO₂ for heat mining for twenty-one geothermal sites in Mexico. This represents the totality of fully characterized geothermal sites in Mexico. The power generation estimate for all the sites is of the order of 1,160 MW_e, representing a 51.4% additional power generation with sCO₂ than with water. Additionally, it was found from the work reported in Reference 18 that the sum of the Mexican sCO₂-based systems would be able to sequester, over an expected 30-year life of the reservoirs, approximately 72 million tons of CO₂. Simulations were carried out using the TOUGH2 code, while neglecting the wellbore flows, and with the evaluation of the CO₂ or water heat mining performance, exclusively depending on reservoir properties and behavior.

212

213This paper reports results of a study focused on exploring the injection of CO₂ from
214fossil fuel power plant for heat mining from geothermal reservoirs in a fully coupled
215wellbore-reservoir system. The system was simulated in an integrated fashion that
216considers the flow of pure sCO₂ in an injection well, interaction of sCO₂ and water in
217a permeable reservoir, initially filled with water, and the flow of the two-phase
218mixture of sCO₂ and water in a production well. A research version of the
219T2Well/ECO2N software was used in the simulations. A symmetry section of a five-
220spot well arrangement was modeled, using a 3-D orthogonal coordinate system.
221Reservoir properties, fluid flow conditions and well arrangement representative of
222similar systems in Mexico and of the CO₂ sequestration industry were used in the
223simulations. The results provide an insight into the behavior of the coupled
224wellbore-reservoir configuration for the CO₂/water mixture. A parametric analysis,
225performed with the integrated model, also provides an indication of a strategy for
226management of the heat mining process.

227

228**2. Modeling Approach**

2292.1 Conceptual Model and Gridding

230The coupled wellbore-geothermal reservoir model considered in this study is
231shown in Figures 2 and 3. The model is a symmetrical box of the five-spot well
232configuration pattern [9]. For the production wells at the edges of the modeling
233domain (Figure 3), it is assumed there are hard rock boundaries, so zero flux
234boundaries were applied. For the box computational domain in the middle, zero flux
235boundaries were applied due to symmetrical flow pattern. Researchers have
236reported modeling results for half of the box shown in Figure 3, divided by the
237diagonal line between the injection and production wellbores [9, 20]. Thus, only 1/8
238of the basic configuration pattern is considered in the model domain. In this study, a
2391/4 model of the basic pattern and the wellbore was modeled. By modeling a box,
240the default mesh generator in the solution solver used in this study was able to be
241applied directly.

242

243The base case dimensions are shown in Table 1 (see also Figure 2). Reservoir
244characteristic parameters for the base case simulation are shown in Table 2. The
245general reservoir parameters were based on measured data from some typical

reservoirs in Mexico [19]. Initial reservoir conditions as well as injection conditions are included in Table 3, where the initial pressure is increased by 10 bar for every 100 m of depth. The heat and mass flux were both assumed to be zero on all reservoir boundaries. Injection wellhead conditions were set at 30 kg/s, 35°C. Production wellhead conditions were set at 200 bar. Along the length of the wellbore on top of the reservoir, a linear temperature distribution was assumed, ranging from 35 to 225°C.

253

A mesh grid of 30×30 cells along the horizontal direction was used, with a finer mesh used near the two wellbores. The depth of the reservoir was equally discretized into 10 layers. This mesh sizing is quite typical for reservoir discretization. For the wellbores, equal cell length of 50 m was used, resulting in 30 cells for the wellbore part above the reservoir. Together there are 9,060 cells.

259

260

Figure 2. Diagram of Coupled Wellbores and Reservoir (see Variable Definition in Table 1)

Figure 3. Plane View of the Five-Spot Well Pattern

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263

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Table 1. Model Dimensions

Wellbore Length Through the Caprock Portion, H_0
--

Injection Wellbore Depth in the Reservoir Portion, H_1
Production Wellbore Depth in the Reservoir Portion, H_2
Length of Reservoir Side, L
Diameter of Injection and Production Wellbores, d_w
Diagonal Distance Between the Injection and Production Wellbore, D
Coordinate or Diagonal Distance with Origin at the Injection Well, X

Table 2. Reservoir Characteristic Parameters

Permeability	30 mD
Porosity	0.1
Rock grain density	2600 kg/m ³
Rock specific heat	920 J/(kg*°C)
Rock thermal conductivity	2.51 W/(m*°C)
Parameters for Relative Permeability [20]	0.01
Residual Gas Saturation	0.65
m_{VG}	0.05
Residual Liquid Saturation	1.00
Saturated Liquid Saturation	
Parameters for Capillary Pressure [20]	0.03
Residual Liquid Saturation	0.4118
m_{VG}	6.06E-5 Pa ⁻¹
Alpha	6.40E+7 Pa
Maximum Capillary Pressure	1.00
Saturated Liquid Saturation	

Table 3. Initial Reservoir and Injection Conditions

Reservoir fluid	All water	Injection fluid	CO ₂
Initial Temperature	225°C	Injection temperature	35°C
Initial Pressure	150-200 bar	Injection mass flowrate	30 kg/s

269

2702.2 Simulator

271The fully coupled wellbore-reservoir simulator T2Well was used in this study.
272Detailed mathematical descriptions and validations of T2Well are available in [21-
27324]. This software is commercially available for temperatures up to 100°C. A high
274temperature research version, provided by Lawrence Berkeley National Laboratory,
275was used in this study, which is capable to provide CO₂-brine mixture property
276values up to 300°C. T2Well incorporates the widely used reservoir-simulation code,
277TOUGH2 [10]. The equation of state model used was the ECO2N V2.0 [25], which
278includes a comprehensive description of the thermodynamic and thermo-physical
279properties of the H₂O-NaCl-CO₂ system in the pressure and temperature ranges for
280typical geothermal systems. In T2Well, the wellbore and reservoir are two different
281subdomains where flow is controlled by different physics. Specifically, viscous flow
282in the wellbore is governed by the 1-D momentum equation, while 3-D flow in the
283porous reservoir is governed by a multiphase version of the Darcy's Law. The mass
284and energy balances are solved together for the two domains, thus capturing the
285coupled behavior between a wellbore and a reservoir.

286

2873. Results and Discussion

2883.1 Base Case

289This section presents simulation results for the base case. Figure 4 shows the
290pressure behavior in the reservoir at different distances, on a diagonal, from the
291injection to the production well. Simulations were run for a period of 30 years. The
292pressure traces in Figure 4 correspond to results obtained from the simulations for
293the top discretized layer beneath the caprock in the reservoir. Initially, the pressure
294in the reservoir quickly increases over the entire reservoir from the initially 150-200
295bar to reach a peak around 445 bar. Then the pressure in the reservoir gradually
296decreases as the gas phase breakthrough the production well (Figure 5). Also a
297large pressure gradient in the reservoir around the production wellbore can be
298observed, as indicated by the bottom two pressure traces in Figure 4. The pressure
299at the production wellhead was set at 200 bar (this boundary condition may be too
300high during the water production period in a real case; although, this pressure level
301would be more realistic for a CO₂ breakthrough), and during the first few years,

302when the production flow is mostly pure liquid water, the production mass flowrate
303of the liquid phase goes up to 50 kg/s, and then it drastically decreases to reach a
304steady flowrate of the order of 30 kg/s (close to the injection flow rate). At the
305steady production flow conditions, more than 80% of the flow mass fraction is CO₂,
306as shown in Figure 5. The CO₂ mass fraction is the flowing fraction (i.e., the ratio of
307CO₂ mass flow rate over the total mass flow rate. However, during the first few
308years of injection, there is a pressure buildup in the reservoir due to the large mass
309flowrate of cold CO₂ being heated in the reservoir. This leads to a large CO₂
310compression inside the reservoir, faster than the available reservoir volume can be
311emptied by the amount of water leaving the reservoir. Pressure spikes inside the
312reservoir are not desirable since they increase the risk of caprock fracture and
313potential CO₂ leakage to the surface.

314

315 When the production is CO₂ dominated, the compression effect is greatly
316reduced, the pressure peak disappears and the flowrate in the production well
317reaches steady state. This pressure peak behavior is quite unique for CO₂ injection
318in a reservoir initially filled with water, which will not happen if the reservoir would
319be initially filled with CO₂. In a real application, there would be limitations in
320compressor work that would prevent injection of CO₂ at the target 30 kg/s for the
321reservoir characteristics used in this study. Strategies would need to be developed
322to prevent the pressure peak from occurring; i.e., during the first few years of CO₂
323injection, a smaller CO₂ injection flowrate could be used, until the CO₂ plume fully
324develops and CO₂ production dominates in the production well. Another option
325would be to open the production wellhead to a lower pressure. Then the injection
326rate could be increased to larger values. Other possible option would be to add
327reservoir pressure relief through water or brine production wells. This option has
328been suggested in other references [17], with further reference to water/brine
329utilization in other production processes, like desalination.

330

Figure 4. Pressure Traces in the Top Layer of the Reservoir

Figure 5. Mass Flowrates (left) and CO₂ Mass Fraction (right) in the Production Well

Figure 6 shows pressures at the injection and production wellhead and well bottom, as well as the pressure gain or loss in the wells and reservoir. Injection pressure

gain is defined as the pressure differential from injection wellhead to well bottom.
 Production well pressure loss is defined as the pressure differential from production
 well bottom to wellhead, while reservoir pressure loss is defined as the change in
 pressure in the reservoir from injection well bottom to production well bottom. It
 can be seen in Figure 6 that the pressure peak in the reservoir is reflected in the
 pressure trace at the injection wellhead. The density difference between the
 injection well and the production well is the main cause for the development of the
 thermosiphon phenomenon in which the injection wellhead pressure is lower than
 the production wellhead pressure. As shown in Figure 6, this happens after about
 13 years when the pressure loss through the reservoir significantly drops because of
 well development of CO₂ plume in the reservoir.

Figure 6. Pressures in Injection and Production Wells

Figure 7 shows temperature plots at the production wellhead and bottom. The
 temperature drop between these two locations is almost constant from well bottom

to head when the production is CO₂ dominated. At about 26 years after the start of injection, the temperature in the reservoir begins to drop and the output temperature at the production wellhead begins to decline. This provides an indication that an optimal well configuration and heat mining strategy are required to exploit geothermal resources with CO₂ in a cost-efficient manner. Figure 8 shows the net energy flow produced from the reservoir. The energy flow is based on the following calculation:

367

$$\dot{Q} = \dot{m}_{pro}^{CO_2} h(P_{pro}, T_{pro}) - \dot{m}_{inj}^{CO_2} h(P_{inj}, T_{inj}) \quad (3.1)$$

369

where $\dot{Q}$ is the energy flow from the production well hot stream, $\dot{m}_{inj}^{CO_2}$ is the injected CO₂ mass flowrate, $h(P_{inj}, T_{inj})$ is CO₂ enthalpy at the injection wellhead, $\dot{m}_{pro}^{CO_2}$ is the pure CO₂ mass flow rate at the production well, and $h(P_{pro}, T_{pro})$ is CO₂ enthalpy at the production wellhead. The fluid generated at the production well will be a rich CO₂ mixture with some entrained water, with a steady state mass fraction of water of less than 10%. The MW calculation assumes that water is separated before further CO₂ heat utilization. It is estimated that for the reservoir used in this study, about 8-9 MW_{th} could be extracted from the geothermal resource for a reservoir section with a volume of 0.08 km³, or an approximate equivalent 100 MW_{th}/km³. During the first two years, the net energy flow is less than zero; this is because there is almost no CO₂ production during the beginning years, while the hot water being produced was not considered to be used to produce energy. For the base case, the total amount of CO₂ being sequestered in the 30-year time lapse is 3.3 Mt in the box domain, or 41.2 kg/m³. The total amount of water being extracted was 5.4 Mt, or 68.1 kg/m³. As the density of water is heavier, more water was extracted.

386

Figure 7. Temperatures at the Production Wellhead and Well Bottom

Figure 8. Net Power produced from the Reservoir

Figures 9 to 11 show contours of pressure, temperature and CO₂ saturation in a diagonal vertical plane between the two wellbores. Results are presented for 1, 5, 15 and 30 years. The highest pressure in the reservoir is located at the injection well bottom, while the lowest pressure is located at the production well bottom. The overall the pressure level in the reservoir decreases throughout the 30-year period. From Figure 10, it can be seen that the temperature in the reservoir drops

399after 30 years. This is consistent with the contours of Figure 11, which show the
 400gradual propagation of CO₂ inside the modeling domain. Figure 11 shows that CO₂
 401concentrates at the bottom of the reservoir, propagating from the injection to the
 402production well bottom, which is also consistent with pressure gradients shown in
 403Figure 9. In this study it was found that this CO₂ behavior greatly depends on the
 404permeability of the reservoir (The CO₂ plume would stay at the top of the reservoir
 405if the reservoir permeability was 15mD.). Figure 11 also shows that by Year 30, the
 406CO₂ gas plume has diffused to almost occupy the entire reservoir volume. It should
 407be noted that the CO₂ saturation values in close to the production well bottom are
 408impacted by the resolution in the computational results achieved by the model grid
 409size. The results in Figure 11 also suggest that well arrangement, in this CO₂
 410utilization application, would be subject of optimization, in order to provide for a
 411system that supplies consistent geothermal energy for the life of the wells. The well
 412arrangement should also be subject to constraints oriented to prevent reservoir
 413over-pressurization and rapid achievement of CO₂ purity and maximum achievable
 414temperature at the production wellhead.

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 418

Figure 9. Pressure Contours at the Vertical Diagonal Plane between the two wellbores

419

420
421 Figure 10. Temperature Contours at the Vertical Diagonal Plane between the two
422 wellbores
423
424
425

426

427 Figure 11. CO₂ saturation Contours at the Vertical Diagonal Plane between the two
428 wellbores

429

4303.2 Sensitivity Analysis

431A sensitivity analysis of seven input parameters used in the simulation was
432performed (see Table 4). Figure 12 shows results of the sensitivity analysis
433corresponding to variations of the pressure specified in the model formulation at the
434production wellhead boundary condition. Results are presented in terms of the
435pressure differential between the injection and production wellhead, CO₂ production
436temperature, net energy flow (see definition in Section 3.1 Eqn. 3.1) and CO₂ mass
437fraction (see Figure 12). The specified pressure at the production wellhead has little
438impact on the thermosiphon effect (production pressure larger than injection
439pressure) of CO₂ utilization in geothermal reservoirs. Similarly, the impact of the
440production pressure is negligible on the net energy flow (this is expected because
441the CO₂ injection rate is fixed) and production stream CO₂ mass fraction. However,
442the impact of the specified pressure at the production wellhead on the output
443temperature at the production wellhead is significant. The higher the production
444pressure, the higher the production temperature. This is mainly because CO₂ is
445compressible fluid so that the temperature is proportional to the pressure for the
446same given specific enthalpy.

447

448

Table 4. Parameters for Sensitivity Analysis

#	Specified pressure at the production wellhead, P_{Pro}
1	
#	CO ₂ injection temperature, T_{inj}
2	
#	Reservoir permeability, P_m
3	
#	Injection flowrate, F_{inj}
4	
#	Reservoir length, L
5	
#	Extension depth of the production wellbore into the 6 reservoir, H_2
6	
#	Diameter of the production wellbore, d_w
7	

449

450

451 Figure 13 shows sensitivity analysis results for injection of CO₂ at temperatures from
452 35°C to 75°C. The output temperature at the production wellhead and
453 corresponding CO₂ mass fraction at the production well are all unaffected by the
454 changes in injection temperature over this range. The thermosiphon effect is
455 slightly affected by this change in injection temperature, because the colder CO₂
456 has larger density which results in less injection wellhead pressure needed to
457 maintain the same injection well bottom pressure to drive the CO₂ through the
458 reservoir to the production well whose wellhead pressure is fixed. This effect was
459 already reported by Reference 19. However, it should be noticed that at the 75°C
460 injection temperature, the thermosiphon effect appears only when close to the end
461 of 30 year operation. It was also found that a higher injection temperature would
462 lead to a lower net energy flow. This is mainly because of higher CO₂ enthalpy at a
463 higher injection temperature.

464

465 Figure 12. Sensitivity Analysis Results for Specified Pressure at the Production
466 Wellhead

467

468 Figure 13. Sensitivity Analysis Results for Different Injection Temperature

469 Figure 14 shows sensitivity analysis results corresponding to different reservoir
 470 permeabilities. A range of permeabilities between 15 to 50 mD was used in the
 471 simulations. The reservoir permeability has a great impact on the pressure
 472 spike seen in previous results at the beginning of CO₂ plume formation. The pressure
 473 peak almost disappears when the permeability is 50md. Additionally, it was found
 474 that when the reservoir permeability is large, higher output temperatures (with the
 475 same production pressure) can be achieved the production wellhead. However, the
 476 impact of reservoir permeability on net energy flow is negligible because of the
 477 small enthalpy variation of CO₂ around 200°C. Figure 15 shows the impact of
 478 injection flowrate on the parameters of interest. It can be seen from Figure 15 that
 479 there is a relationship between injection flowrate of CO₂ and the magnitude of the
 480 pressure spike in the reservoir, further indicating that for certain reservoir
 481 characteristics and dimensions, there may be a maximum injection flowrate below
 482 which prevention of pressure spikes is possible. As expected, the CO₂ injection flow
 483 rate directly controls the production flow rate since a stable injection-production
 484 state is established after a few years of injection (see Figure 5); thus, resulting in a
 485 steady net production energy flow. However, larger injection flow rates could result
 486 in a faster depletion of the geothermal energy reserve in the reservoir.

487

488

489 Figure 14. Sensitivity Analysis Results for Different Reservoir Permeability

490

491 Figure 15. Sensitivity Analysis Results for Different Injection Flowrate

492

493 Figures 16 to 18 show sensitivity analysis results as function of production well
494 dimensions and configuration. It can be seen from Figure 16 that larger distances
495 between the locations of the injection and production wells will ensure that the
496 output temperature at the production wellhead will not decline toward the end of
497 the site production life for the same injection flowrate of 30 kg/s. A larger well
498 spacing also contributes to a smaller peak of reservoir pressure. These are all
499 because the larger well spacing means larger capacity of the reservoir involved. As
500 expected, the impact of the distance between both injection and production wells
501 has a negligible impact of produced net energy flow and mass fraction except the
502 early transient period. Figure 17 shows sensitivity analysis results on the impact of
503 extending the depth of the production wellbore into the reservoir. A shallower
504 production wellbore resulting in larger initial pressure spikes because of its smaller
505 well-reservoir interface area (i.e., larger resistance to flow. The impact of this
506 parameter on the produced CO₂ conditions (net energy flow, CO₂ mass fraction and
507 production temperature) is negligible. It is important to notice that the estimation
508 of the effect of the arrangement of the wellbore in the reservoirs would not be
509 possible without a simulation like the one of this study, which couples the wellbores
510 and reservoir in an integrated fashion. Lastly, Figure 18 shows the impact of the
511 production wellbore diameter on performance parameters. In the figures, a larger
512 bore diameter has twice the section area than a smaller diameter wellbore. It was
513 found that this parameter plays no significant role in the operation of the integrated
514 system with fixed production pressure and fixed injection rate, except the pressure
515 difference between injection and production wells.

516

517 Figure 16. Sensitivity Analysis Results for Different Distance Between Injection and
518 Production Wells

519

520 Figure 17. Sensitivity Analysis Results for Different Extension Depth of the
521 Production Wellbore into Reservoir

Figure 18. Sensitivity Analysis Results for Radius of the Production Wellbore

5254. Conclusions

526The concept of injecting sCO₂ into a geothermal reservoir was investigated
527computationally to obtain an insight into the performance of such system in terms
528of the benefit of using CO₂ captured from fossil fuel power plants for geothermal
529heat mining. This approach is of interest to Mexico, since it combines CO₂ capture
530and sequestration, geothermal energy extraction and enhanced electric power
531generation. The Mexican government is committed to reduce its carbon footprint
532and it has set targets to cut national GHG emissions by 22% below baseline in 2030.
533A fully coupled wellbore-reservoir system was simulated using a research version of
534the Lawrence Berkeley National Laboratory's T2Well/ECO2N software. The system
535was simulated in an integrated fashion, considering the flow of pure sCO₂ in an
536injection well, interaction of sCO₂ and water in a permeable reservoir, initially filled
537with water, and the flow of the two-phase mixture of sCO₂ and water in a production
538well. Reservoir properties, fluid flow conditions and well arrangement
539representative of similar systems in Mexico and of the CO₂ sequestration industry
540were used in the simulations.

A base case simulation was first performed. Results of this simulation indicate that, despite a pressure peak that can develop during the initial stage of CO₂ injection, this CO₂ application is capable of providing a good source of renewable energy. It was found that for the reservoir section used in this study (0.08 km³) about 8-9 MW_{th} could be extracted from the geothermal resource in a steady state fashion, for a lifetime of the wells of 30 years. This is approximately equivalent to 100 MW_{th}/km³. A sensitivity analysis of the coupled wellbore-reservoir system provided information on the impact of certain parameters, such as injection flow rate and temperature, and well configuration on the performance of the integrated system. It is found that the mass flow rate and temperature of injected CO₂, and reservoir permeability have a first order impact on the pressure management of the reservoir. Injection flow rate and temperature have additional impact on the amount of heat mining from the CO₂-based geothermal reservoir. Additionally, CO₂ injection temperature has a large effect on the thermosiphon characteristic of this type of systems, where the pressure differential between production and injection wellhead pressure is positive. From the sensitivity analysis it was evident that system optimization is warranted on these integrated wellbore-reservoir arrangements, to provide a set of optimal operating conditions and well configuration that will result in a cost-effective geothermal resource exploitation.

561

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563

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574 **6. References**

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