Profitability Evaluation of a Hybrid Geothermal and CO₂ Sequestration Project for a Coastal Hot Saline Aquifer.

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Abstract

With growing interest in commercial projects involving industrial volume CO₂ sequestration, a concern about proper containment and control over the gas plume becomes particularly prominent. In this study, we explore the potential of using a typical coastal geopressured hot saline aquifer for two commercial purposes. The first purpose is to harvest geothermal heat of the aquifer for electricity generation and/or direct use and the second one is to utilize the same rock volume for safe and controlled CO₂ sequestration without interruption of heat production. To achieve these goals, we devised and economically evaluated a scheme that recovers operational and capital costs within first 4 years and yields positive internal rate of return of about 15% at the end of the operations. Using our strategic design of well placement and operational scheduling, we were able to achieve in our numerical simulation study the following results. First, the hot water production rates allowed to run a 30 MW organic Rankine cycle plant for 20 years. Second, during the last 10 years of operation we managed to inject into the same reservoir (volume of 0.8×10^9 m³) approximately 10 million ton of the supercritical gas. Third, decades of numerical monitoring the plume after the end of the operations showed that this large volume of CO₂ is securely sequestered inside the reservoir without compromising the caprock integrity.

Keywords: CO₂ sequestration; geothermal energy; dynamic plume control; hybrid energy systems

Introduction

At the beginning of the 1980s, when crude oil price soared to new historical highs, the US DoE started to investigate alternative energy sources that could provide abundant energy for electricity generation in highly populated coastal regions. As a part of the DoE initiative called “Wells of Opportunity” [1], the engineers established that geothermal potential of the Gulf of Mexico (GOM) coastal region was tremendous and highlighted that already drilled oil and gas wells can be used for economic production of hot geofluid for power generating plants. Though GOM geofluid tends to have low enthalpy [2], several pilot projects in this region demonstrated sustainably high geofluid production rates and promising power generation capacities. For example, in the 1990s, Riney [3] completed a report about the Pleasant Bayou project in Texas during which the engineers achieved production rates around 20,000 bbl of hot water per day and successfully converted mechanical and thermal energy into the total of 3,445 MWh using a hybrid binary cycle system.

After this successful attempt to assess viability of low-temperature geothermal development in hot saline aquifers, a number of authors investigated economic potential and profitable reservoir engineering design for geopressured geothermal systems. In their reservoir simulation study, Plaksina and White [4] provide a comprehensive overview of the GOM key projects including the discussion about hot water production rates achieved in the area, the hazards of land subsidence and loss of caprock integrity that become important during industrial size CO₂ sequestration activities.

Although the pilot projects demonstrated that it was possible to achieve high hot water production rates and thus, generate commercial electricity output, economic potential of a geopressured geothermal project can be further improved if the same reservoir is also used for secure CO₂ sequestration. Garapati et al. [5] proposed to use CO₂ as a secondary fluid that could displace hot reservoir water geofluid to the producing wells and placed these injection wells to mitigate the hazard of the uncontrolled CO₂ plume. With their numerical design, the authors managed to sequester approximately 2 to 4 Mtons of the supercritical gas without causing a significant damage to the caprock by the high gas concentration plume.

To eliminate the hazard of the plume and ensure caprock integrity, we propose to use strategic placement of cold water injection wells that can reduce gas concentration and keep the plume away from the caprock. In his thesis, Anchliya verified with numerical simulation that simultaneous injection of CO₂ in the middle or lower portion of the reservoir and cold water on top of the reservoir can diffuse the high concentration plume and keep it away from the caprock, thus,

preventing the possibility of its fracturing and leakage of the gas to the upper formations and ultimately to the surface [6].

In this study, we use a typical hot saline aquifer geomodel from the Gulf of Mexico and offer an integrated approach to modeling and evaluation of the entire life cycle of this geopressured geothermal aquifer that can be found in many thick coastal sedimentary systems around the globe and used for simultaneous greenhouse gas sequestration and heat extraction [4]. Specifically, first, we develop a conceptual model of a strategic well placement and then a simulation flow model implementing this well arrangement. Second, we generate hot fluid production and CO₂ injection history based on this model and well placement, and evaluate the quantity of supercritical CO₂ gas that can be safely and permanently sequestered inside the same reservoir. Third, we numerically monitor the reservoir for several decades to ensure that the gas plume is sufficiently dispersed and poses no threat to the caprock. Final, using the obtained production and injection history, we assess economic viability of this heat harvesting project using NREL CREST tool developed for economic assessment of geothermal projects [7].

Methodology

In this section, we present our approach to modeling of a geopressured geothermal sedimentary reservoir, the setup of the model, some practical considerations behind well placement, and description of the production and injection goals.

Simulation Model and Production Arrangement

To construct a simulation model that reflects features of an actual aquifer, we conducted a survey of reports and scientific literature about potential low-enthalpy geothermal reservoirs in the US Gulf Of Mexico region. In the last several decades, the researchers have identified a number of potentially suitable geopressured formations, properties of which were derived from well logs and field well tests [8-9]. Note, that even though the presented geothermal prospects are found at depths of more than 4,000 m, their permeability is relatively high due to geopressure caused by fast burial of sand. Moreover, in such geopressured formations, overburden is mostly maintained by the incompressible pore fluid rather than touching rock grains, as a result we might observe both high porosity and permeability. Another important observation for these reservoirs is that their depth is not always the most influential factor in the formation temperature. For example, Camerina A sand due to its proximity to a salt dome has a thermal anomaly. Because of its thermal conductivity, salt transfers high amounts of heat from deeper hotter layers to shallower colder sand deposits [9]. Thus, it is possible to encounter anomalously high formation temperatures in this generally low temperature subsurface region.

Table 1 provides a summary of all relevant petrophysical, thermodynamic, and geometric properties surveyed from the literature and used in our geopressured geothermal reservoir model.

Table 1. Properties of the geothermal reservoir adopted in the simulation model [4].

<i>Property</i>	<i>Values</i>	<i>Unit</i>
Quarter model dimensions (width x length x thickness)	1000 x 1000 x 200	m
Initial formation pressure	80 or 11600	MPa or psi
Initial average formation temperature	140	°C
Reservoir rock density	2600	kg/m ³
Geothermal gradient	29	°C/km
Horizontal wellbore length	1000	m
Production period duration	20	years
Rock matrix porosity	20	%
Rock matrix compressibility	2.0×10^{-8}	1/Pa
Wet rock heat conductivity	2.0	W/m °C
Rock matrix permeability	200	md
Geofluid salinity	0	ppt
Re-injected cold water temperature	35	°C

Fig. 1 shows the geometry and initial pressure distribution inside the model going from approximately 80 MPa at the top of the reservoir to 81.5 MPa at the bottom. To adequately model constant heat flux from the lower hot layers to the producing formation, we assigned very high heat capacity to the bounding layers (shale layers with infinite heat capacity). This approach ensures constant heat conduction from the hotter lower lying layers to the reservoir without fluid influx.

Figure 1. Geometry of a quarter of the geopressured geothermal reservoir (1000 m long, 1000 m wide and 200 m thick) (modelled in CMG STARS).

In his investigation of CO₂ plume control during industrial volume sequestration operations, Anchliya proposed to place a supercritical gas injection well underneath a cold water injector [6]. Such arrangement is reasonable from a fluid movement point of view and feasible from an engineering standpoint. **Fig. 2** provides visual demonstration of how cold water injector can help prevent formation of a high gas concentration plume, efficiently disperse the supercritical gas inside the reservoir, and avoid caprock integrity problems. Due gravity, cold re-injected water tends to move down toward the bottom of the reservoir and push supercritical gas plume away from the caprock and to the side of the formation. In the results section, we will demonstrate whether our arrangement performs according to this theoretical understanding and expectation of fluid flow and reservoir dynamics.

Figure 2. The central portion of the geothermal reservoir with CO₂ injection wells and cold water re-injection wells.

Coupling Subsurface Design with Surface Facilities and Power Output Considerations

Because geopressed geothermal systems produce geofluid of relatively low temperature (and therefore, low enthalpy), we cannot use flash conversion systems that require fluids of more than 200°C [2]. Instead, low-enthalpy geothermal development can take advantage of a binary cycle system such as a binary organic Rankine cycle (ORC) system. This energy conversion system works with geofluids of approximately 150°C (sometimes all the way down to 100 or up to 220°C) and has a number of economically attractive characteristics. Specifically, because of the low enthalpy drop inside a turbine, it can have much simpler design and, therefore, cost. Also the geofluid is not used directly like in typical flash systems. Instead, using a heat exchanger, the primary fluid (hot brine) heats the secondary one (isobutane or R-134a) and never enters the turbine or the condenser. This can be very important especially if the geofluid contains highly corrosive gas

impurities. The use of a secondary fluid also ensures superheating at the end of the expansion cycle, this helps avoid condensation and precipitation on the turbine and extend its lifetime [10].

The heat exchanger for the binary cycle is usually designed in the way that does not allow primary and secondary fluid to interact. Once the secondary fluid is superheated, it is passed to the turbine to generate electricity. After that the secondary fluid is cooled in the condenser and passed back to the heat exchanger. In the second part of the project (another ten years), two extra horizontal producer wells (wells **1** and **2**), CO₂ injection (location **3**) and cold water re-injection wells (location **4**) are drilled (or extended from the shallower wells). At this stage the formation pressure is reduced to a half of its initial value and is sufficiently depleted in its central portion. Now, the central part of the reservoir can be used for CO₂ sequestration and dynamic plume control while still maintaining commercial volumes of hot geofluid production from the sides of the reservoir. Now, produced and cooled water from all producer wells is pumped back through re-injection well to push the plume away from the caprock and toward the side of the reservoir.

To model behavior of this complex geopressured system on the subsurface level, we chose CMG STARS simulator because its EOS can handle extremely high pressures usually observed in deep saline aquifers [11]. EOS of CMG STARS can simulate fluid flow for pressures above 80 MPa. In addition to the active production phase of the project, we also modeled quiescent period after the heat extraction to monitor the plume behavior.

Results

After ten years of hot water production at 1200 m³/day from the production wells (or quarter of the reservoir), the reservoir pressure is sufficiently lowered to start injection of CO₂ and cold water. **Fig. 3** shows three snapshot of the reservoir throughout the second phase of the project. The production wells are producing at 2400 m³/day each, cold water re-injection wells pumps 2400 m³/day back into the formation, and CO₂ injection wells injects 80,000 m³/day of the supercritical gas. Note that the entire reservoir cools below 140°C at the end of the second phase of the project. We can also observe that high cold water injection rate creates a large front that engulfs the central portion of the reservoir with the stacked wells.

Figure 3. Temperature distribution inside the reservoir (sides with wells 1 and 2 are truncated to focus on the central part) after a) 1 year, b) 5 years, and c) 10 years of cold water re-injection and CO₂ injection. Locations 1 and 2 correspond to the production wells, location 3 is the CO₂ injection wells, and location 4 is cold water re-injection wells.

These simulation results confirm that the cold water front is large enough to push the gas plume down. **Fig. 4** presents snapshots of the gas saturation distribution during the second phase of the project corresponding to same time snapshot in **Fig. 3**. The juxtaposition of the two figures clearly illustrates the success of the dynamic control idea. Only toward the end of the project two small tails of low concentration gas plume reach the top of the reservoir. Moreover, the concentration of gas everywhere in the reservoir is less than 15% at the end of the operations. We can claim that dynamic control injection wells can be an effective tool to avoid well-defined gas plume and keep it away from the caprock.

Figure 4. Distribution of CO₂ gas saturation inside the reservoir (sides beyond wells 1 and 2 are truncated to focus on the central part) after a) 1 year, b) 5 years, and c) 10 years of cold water re-injection and CO₂ injection.

It is widely known that projects involving CO₂ injection do not usually end with the end of injection operations. Such projects require extended monitoring of fluid movement and concentration inside the reservoir. **Fig. 5** offers the results of monitoring activities for 180 years after completion of the project. Note that even though the shape of the distorted gas plume does not change significantly over time, the concentration in the final snapshot (**Fig. 5**) is less than 1%.

Figure 5. Monitoring concentration of CO₂ gas inside the reservoir after a) 30 years, b) 80 years, and c) 180 years after finishing cold water re-injection and CO₂ injection.

The simulation results above reflect the subsurface aspect of our investigation. However, we posed a broader scope for this study and included the analysis of commercial potential of our geopressured geothermal project. To evaluate economic aspect of the project, we decided to use an elaborate model NREL CREST for cost analysis of renewable energy projects [7]. This model requires some essential input information that come both from our simulation results and literature survey of similar pilot projects. Note that in this model we accounted for tax credit for our CO₂ sequestration activities by adding US\$40,000,000 as an additional federal grant [12]. Based on this US policy, the project can qualify for \$20 per metric ton of CO₂ sequestered. Our simulation results show that we comfortably injected about 1 million metric tons of CO₂ during 10 years in the entire reservoir (the results above including rates are given for a quarter of the reservoir). Thus, US\$40,000,000 can be added to the economic model.

Hot water production rates from the entire reservoir can maintain power generating capacities of about 30 MW. This value can also be achieved from scaling the pilot project at Pleasant Bayou which ran 10 MW capacity on rate of 1200 m³/day of geofluid of comparable thermodynamic properties. After compiling a detailed cash flow model for 20 years of the project, we obtained internal rate of return after tax (IRR) is 15% in the last year which is good value for a type of project that has always been considered sub-commercial.

The most conservative estimates of the project performance are demonstrated in **Fig. 6** with cross-plot of expenses vs. revenue based on the NREL CREST economic analysis. Note that for the analyzed project based on the simulation model expenses never exceed revenue, which is a good indicator of commercial attractiveness of the project. These results are conservative, because we used very stringent tax regime and terms in NREL CREST model.

Figure 6. Plot with (a) yearly revenue vs. expenses generated in NREL CREST geothermal model and (b) cumulative cash flow generated in NREL CREST geothermal model.

Discussion

The results of the geothermal reservoir simulation coupled with previous field pilots and the output from the economic model have demonstrated an encouraging prospect: it is possible to develop a geopressed geothermal reservoir economically and simultaneously achieve several other goals. One of such goals is secure and permanent sequestration of considerable amounts of CO₂ gas. Our simulations show that dynamic control injection wells can effectively disperse the plume and keep it away from the caprock to prevent leakage and/or fracturing. Although in our study we successfully pumped and monitored excess of 10 million tons of the gas, the formation pressure and our dynamic control strategy allows to increase this amount even further to exceed those of currently commercial CO₂ sequestration sites (4 to 10 million tons or 1 million tons per year). These results can be achieved even with the reservoir of choice for this study (bulk rock volume of $0.8 \times 10^9 \text{ m}^3$). Higher gas injection volumes might also add extra leverage in the economic part of the project and help cover some of capital expenditures.

However, the biggest consideration in increasing volumes of CO₂ injection is the reservoir thickness and permeability. Thicker and tighter formations (but not necessarily less porous) might be good candidates for storing higher volumes of the supercritical gas. Thus, primary depletion of geopressed reservoirs is a necessary step before sequestration not only because of high injection cost, but also because of rock compaction which causes reduced permeability, higher capillary forces, and ultimately lower relative permeability. This will ensure proper and safe storage of high volumes of CO₂ without the plume rising dangerously close to the caprock.

Conclusions and Future work

In our investigation, we pursued two main objectives: model the subsurface reservoir dynamics of a geopressured geothermal system under production and injection and evaluate commercial potential of such development project. Our simulation study solved two-fold problem of reconciling hot geofluid production with cold water re-injection and secure sequestration of substantial volumes of CO₂.

This study opens multiple possibilities for future investigations. Among further research directions are:

1. Automated optimization strategies for well placement controlled by geology and economic parameters (perhaps, an elaborate revenue function that includes elements of NREL CREST cash flow model);
2. Multi-objective optimization for sequestration projects with or without geothermal heat harvesting. This approach will help weight different and sometimes competing objectives (higher hot water volume and higher volume of injected CO₂ could be competing if the latter floods producing wells);
3. Incorporation of salinity effects, assessing its impact on density-driven convection inside the reservoir and potential for CO₂ sequestration (higher salinity leads to poorer sequestration potential).

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