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Title: Offsetting Water Requirements and Stress with Enhanced Water Recovery from CO_2 Storage

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Abstract:
Carbon dioxide (CO_2) capture, utilization, and storage (CCUS) operations ultimately require injecting and storing CO_2 into deep saline aquifers. Reservoir pressure typically rises as CO_2 is injected increasing the cost and risk of CCUS and decreasing viable storage within the formation. Active management of the reservoir pressure through the extraction of brine can reduce the pressurization while providing a number of benefits including increased storage capacity for CO_2, reduced risks linked to reservoir overpressure, and CO_2 plume management. Through enhanced water recovery (EWR), brine within the saline aquifer can be extracted and treated through desalination technologies which could be used to offset the water requirements for thermoelectric power plants or local water needs such as agriculture, or produce a marketable such as lithium through mineral extraction. This paper discusses modeled scenarios of CO_2 injection into the Rock Springs Uplift (RSU) formation in Wyoming with EWR. The Finite Element Heat and Mass Transfer Code (FEHM), developed by Los Alamos National Laboratory (LANL), was used to model CO_2 injection with brine extraction and the corresponding pressure tradeoffs. Scenarios were compared in order to analyze how pressure management through the quantity and location of brine extraction wells can increase CO_2 storage capacity and brine extraction while reducing risks associated with over pressurization. Future research will couple a cost-benefit analysis to these simulations in order to determine if the benefit of subsurface pressure management and increase CO_2 storage capacity can outweigh multiple extraction wells with increased cost of installation and maintenance as well as treatment and/or disposal of the extracted brine.

Introduction:

The rise of carbon dioxide (CO_2) in the atmosphere is having an increasingly alarming impact on global climate. This is exacerbated as the rate at which human activities emit CO_2 is at least ten times the pace that has occurred over the past 66 million years[1]. These high CO_2 emission rates necessarily require research pathways that address climate change through CO_2 sequestration while national and international policies and agreements promote CO_2 capture and storage (CCS) research. For example, the United States (U.S.) Clean Power Plan mandates the reduction of CO_2 produced by electricity production and the U.S. submission to the United Nations Framework Convention on Climate Change (UNFCCC) agrees to reduce CO_2 emissions by 26-28% below 2005 levels by 2025[2,3].

CO_2 capture, utilization, and storage (CCUS) operations capture and sequester large quantities of CO_2 providing a storage option for the high amount of CO_2 emitted to the atmosphere. Sequestration of CO_2 into a saline aquifer provides considerable storage possibilities and the potential to extract brine through Enhanced Water Recovery (EWR). The pressure of the aquifer can be managed through the simultaneous injection of CO_2 and extraction of brine, which has previously been studied as a pressure management technique[4]. The extraction of brine not only manages the subsurface pressure, but provides several benefits to the sequestration operation which include (1) increase CO_2 storage capacity, (2) reduced risks linked to reservoir pressure such as seismicity and wellbore leakage, (3) active CO_2 plume management, and (4) beneficial water use from desalinating the extracted brine[5,6]. Coupling the treatment of brine extracted during CCUS operations is particularly interesting as it could use extracted brine that would previously be disposed and identify an additional water source to be treated and used as the cooling water requirement for thermoelectric power operations or some other societal need without consuming current water supplies in a region, or produce a marketable such as lithium through mineral extraction.

This research focuses on understanding EWR through injecting CO_2 at a constant pressure coupled with hydrostatic brine extraction at specified wells. The number and location of these wells can manage the pressure of the reservoir while controlling the amount of CO_2 sequestered and brine extracted. These reservoir simulations can be coupled with a cost-benefit analysis in order to determine if the benefit of subsurface pressure management and increase CO_2 storage capacity can outweigh the addition of multiple extraction wells with increased cost of installation and maintenance as well as treatment and/or disposal of the extracted brine.

Methods:

The Finite Element Heat and Mass Transfer (FEHM) Code, developed by Los Alamos National Laboratory (LANL), was used to simulate CO_2 and brine injection, extraction, and flow within a deep, saline aquifer. FEHM uses the control volume finite element method (CVFE) to simulate subsurface multi-fluid, multi-phase heat and mass transfer or complex subsurface processes in geologically complex basins[7]. The Rock Springs Uplift (RSU) formation was used as the targeted formation for these series of subsurface simulations as it was previously studied and characterized through several DOE funded projects specifically interested in CCUS (DE-FE0002142, DE-FE0009202, DE-FE0026159, and DE-FE0023328) and Surdam's subsurface characterization through 3-D seismic surveys, well logs, and cores[8]. Additionally, Los Alamos National Laboratory (LANL) built a heterogeneous mesh of the RSU Lower Madison formation providing a realistic media to run subsurface flow simulations. The mesh consists of a 6 by 6 km top surface area with the Lower Madison formation at an approximate depth between 2.8 to 4.3 km. The Jim Bridger's fault is characterized as a sealing fault through assigned porosity values of zero while the Lower Madison formation permeability and porosity are heterogeneously defined through previous subsurface characterizations previously mentioned. The Upper Madison formation as well as other formations outside of the Lower Madison Formation are assigned a low permeability of 1×10^{-18} m^2 and a porosity of 0.01, in order to model these formations as potential cap-rock seals during CO_2 injection. Additionally, the mesh is constructed as a sealed domain, which assumes boundaries are sealed, opposed to an open flow boundary which permits movement of CO_2 or brine outside the boundaries of the mesh.

Scenarios, using the FEHM code, were developed in order to study the impact of CO_2 injection and brine extraction within the RSU Lower Madison formation. Figure 1 is a basic diagram of the RSU mesh and includes the location of the CO_2 injection well (RSU#1), the brine extraction wells (Well A, Well B, Well C, and Well D), and the Jim Bridger's fault line. Each scenario involves CO_2 injection at the RSU#1 Well in the center of the RSU mesh at a constant pressure, approximately 2 MPa higher than the initial pressure at the injection location. Once brine extraction wells are added, brine is extracted hydrostatically from each well.

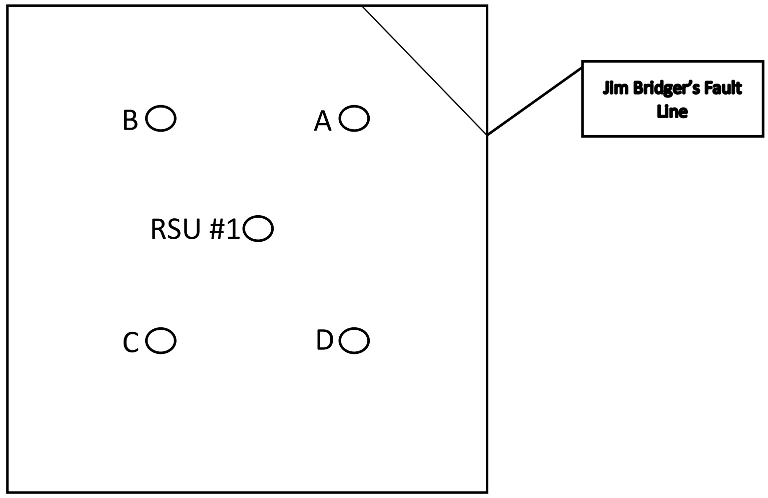

Figure 1: Outline of RSU formation and approximate injection and extraction well locations and the Jim Bridger's Fault.

In order to understand how pressure buildup is relieved through brine extraction within the RSU formation, the baseline scenario injects CO_2 at a constant pressure at the RSU#1 Well with no brine extraction. For each additional scenario, an extraction well is added in order to understand how pressure can be managed through added brine extraction wells.

Scenario 1 – No brine extraction (baseline)
Scenario 2 – Brine extracted at hydrostatic pressure from Well A
Scenario 3 – Brine extracted at hydrostatic pressure from Well A and Well B
Scenario 4 – Brine extracted at hydrostatic pressure from Well A, Well B, and Well C
Scenario 5 – Brine extracted at hydrostatic pressure from Well A, Well B, Well C, and Well D

Each additional extraction well impacts the overpressure of the formation induced through the injection of CO_2 from RSU#1 Well. This facilitates visualization of pressure changes and compares the amount of CO_2 that is stored within the injection cycle and the amount of brine extracted by each well.

Results:

The FEHM simulations produced overpressure contours of the injection of CO_2 at RSU#1 Well and extractor locations at Wells A, B, C, and D (refer to Figure 1). Each simulation consisted of constant pressure injection at RSU#1 Well and hydrostatic extraction at wells for 2 years. Extraction at hydrostatic conditions maintains an overpressure of zero MPa for the formation. Figure displays these overpressure contour maps for each scenario modeled.

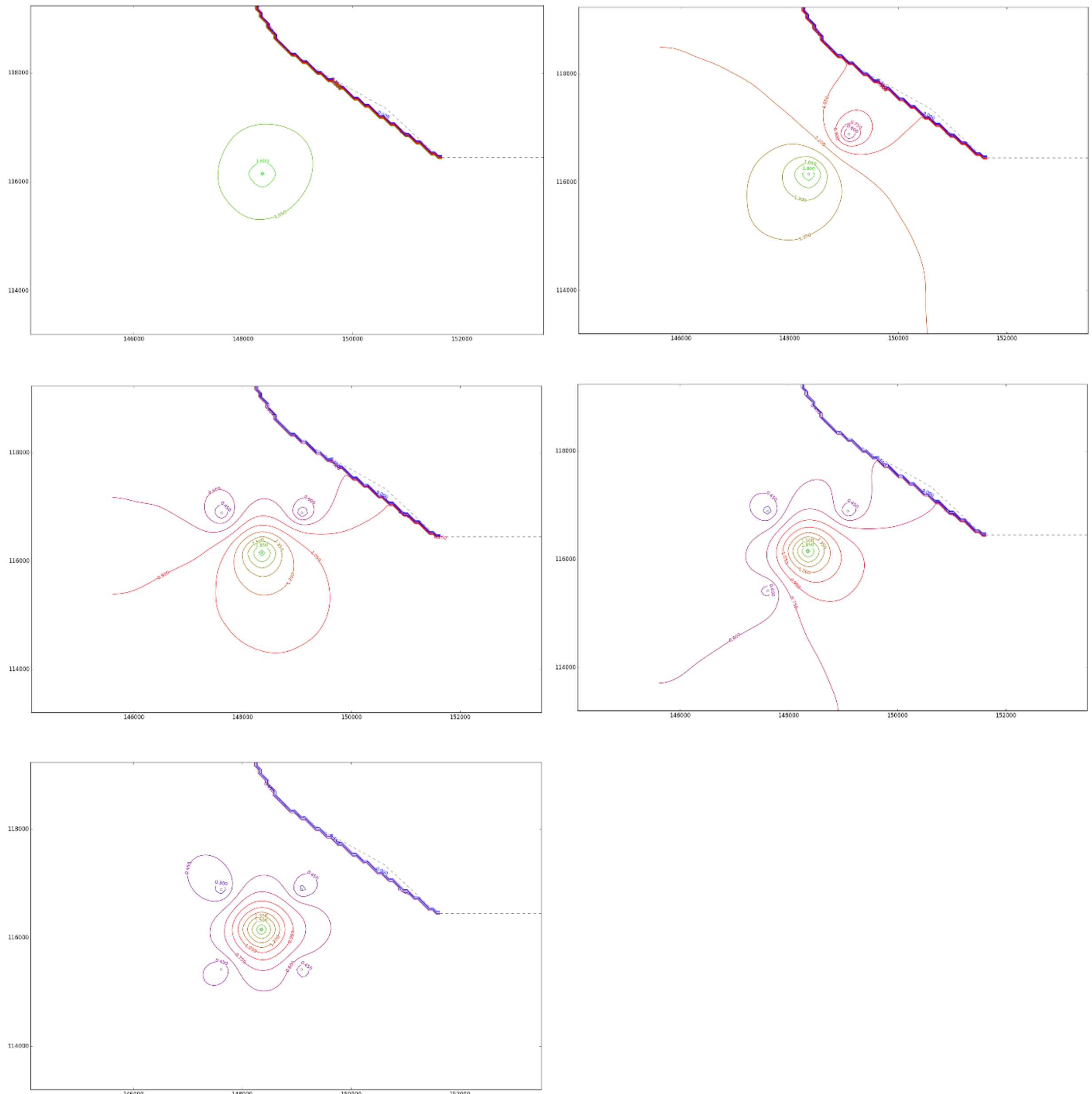

Figure 2: Overpressure contours in MPa at 2 years and a contour interval of 0.15 MPa. The first figure is the baseline scenario with no brine extraction wells. Subsequent figures add additional wells for each scenario with a maximum of four wells surrounding the RSU#1 injection well. A dashed line indicates the Jim Bridger's Fault, which acts as a sealing fault, and open circles indicate well locations. Axes are in the SPC27-4903 coordinate system in meters.

The overpressure plots visually represent pressure management strategies. As extraction wells increase, each contour plot adjusts to the pressure relief of the extraction well visualized through the overpressure cones of depression. Additionally, the CO_2 plume adjusts to each extraction well which is noticeable for the scenarios with multiple extraction wells as extraction wells limit the span in which the CO_2 overpressure plume reaches the surrounding wells and mesh. The Jim Bridger's sealing fault is impacted through contours that stack-up on the fault boundary line.

The addition of each extraction well increases the amount of CO_2 injected into the formation. Due to the pressure relief of the extraction wells, more CO_2 is sequestered to take the space previously occupied by brine within the saline formation. Figure displays a time series plot with the amount of CO_2 (tonnes) that is injected over the 2 year run time. As the number of extraction wells increases, the amount of CO_2 sequestered increases, which indicates the need for additional extraction wells to maximize the CO_2 storage capacity. Figure displays the brine extraction over the 2 year operation time that maintains hydrostatic pressure at the wellhead. Similarly, the increase in extraction wells results in an increased rate of brine extraction for the entire simulation. This brine could then be treated and used as the cooling water requirement for thermoelectric power plants, satisfy other societal water demands, or produce minerals such as lithium through mineral extraction.

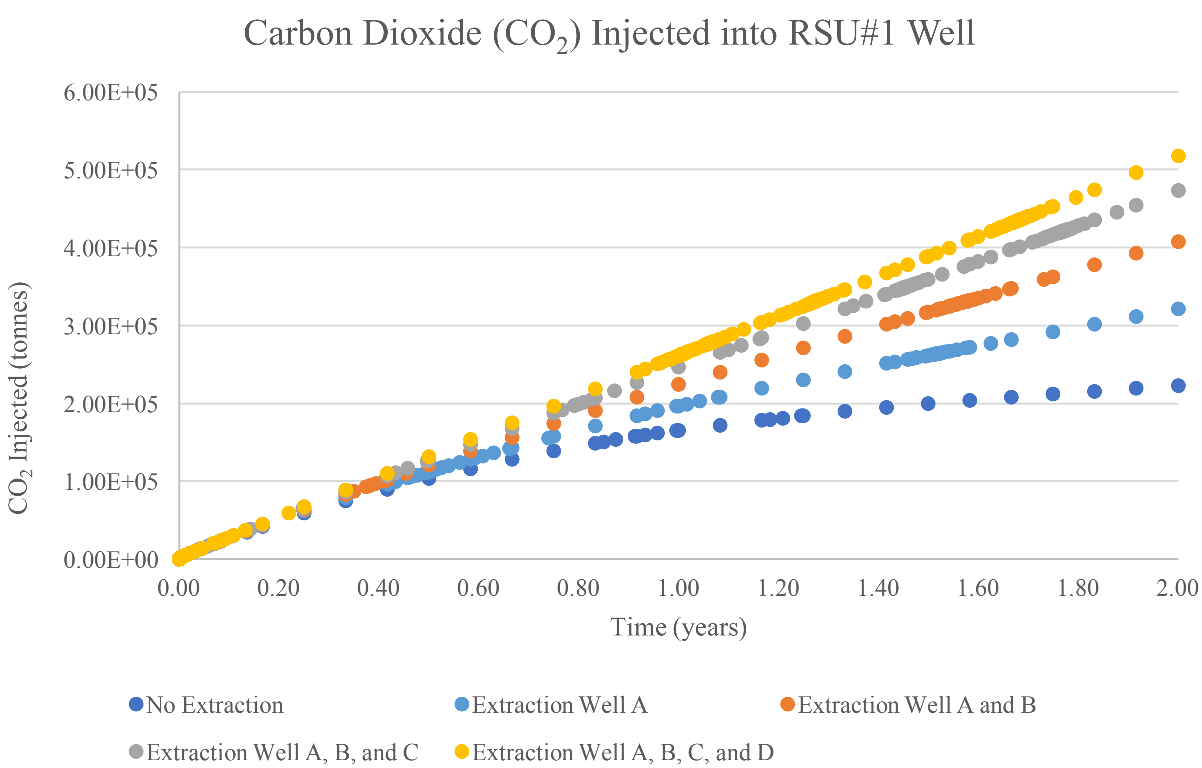

Figure 3: Time-step of CO_2 injected into the RSU#1 Well for all simulated scenarios

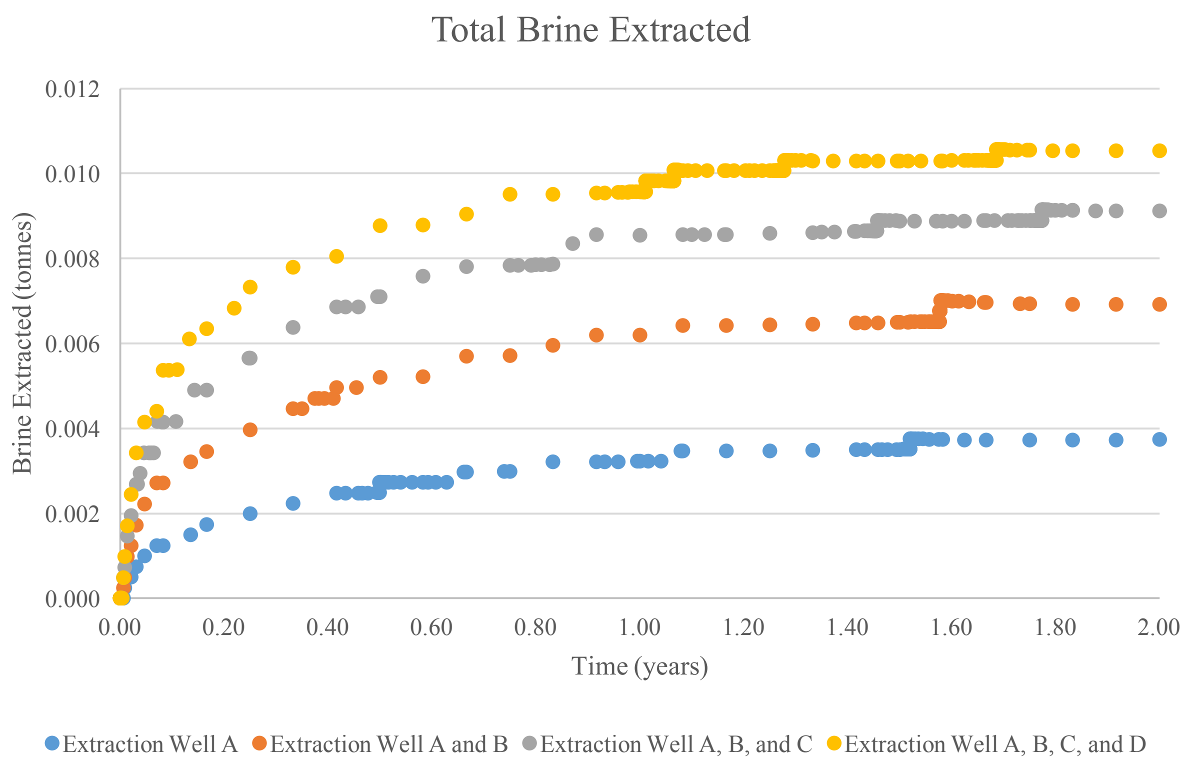

Figure 4: Brine extraction rates for simulated scenarios with extraction wells activated.

Conclusions:

The FEHM simulations described in this paper indicate that brine extraction wells can be used as a form of pressure management during CCUS operations and impact the CO_2 storage capacity within the aquifer formation. Each additional extraction well impacts the subsurface pressure through increased brine extraction and the resulting increased CO_2 storage capacity. These initial simulations are important to understand how to CO_2 and extracted brine flow within a heterogeneous formation and impact extraction rates in order to generate a model that represents a more realistic reservoir. The results can then be used to compare overpressure within a reservoir and the resulting brine extraction rates, CO_2 injection rates, and number of extraction wells used as pressure management strategies.

Future Work:

Continued research is needed within this area of subsurface pressure management. The FEHM simulations provided reasonable results that indicate motivation for continued work specifically targeting the number of extraction wells within a CCUS system. Extraction wells facilitate pressure management through the extraction of brine during EWR and provide increased storage capacity for CO_2, yet additional wells add significant expenses to a CCUS operation. A key component of this research consists of a cost analysis of the construction and operation of each additional extraction well, the transportation, storage, treatment, and disposal of extracted brine, and the benefit of added CO_2 storage capacity and pressure management. This analysis could produce a cost per ton of CO_2 injected into a reservoir and compare it to the cost per ton of brine extracted, treated, and disposed then weigh the benefits of pressure management and increased CO_2 storage. The cost for brine treatment, which is highly dependent on water chemistry and intended water use, and the expense of additional brine extraction wells could be substantial resulting in the need for a cost-benefit analysis in order to determine if this pressure management strategy could be implemented in a CCUS-EWR operation.

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