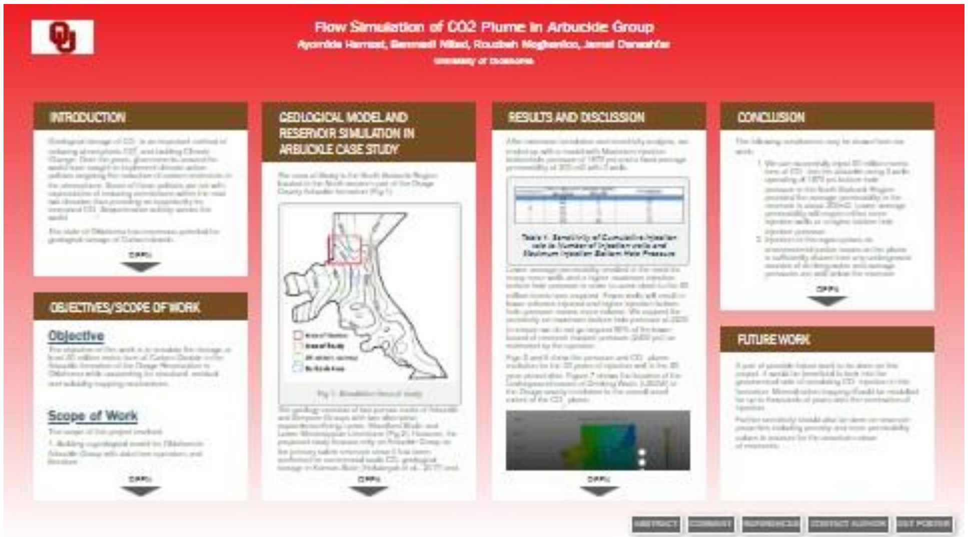
Flow Simulation of CO_2 Plume in Arbuckle Group



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ABSTRACT

This paper presents the groundwork for a proposed CO_2 sequestration project in Osage County, Oklahoma. It describes the flow simulation of the CO_2 plume in the saline Aquifer of the Arbuckle Group, a dolomite formation proposed as a potential large-scale storage reservoir for CO_2 in the state of Oklahoma. Geological storage of CO_2 is one of the most potent tools in use today for reducing atmospheric CO_2 and battling Climate Change. Moreover, with governments around the world putting policies in place to significantly reduce carbon emissions within the next two decades, there is an expectation for more CO_2 Sequestration projects across the world.

This study uses a geological model of the formation to simulate the injection of over 50 million metric tons of CO_2 in a 30-year period. We successfully built a carbon sequestration model with 3 injection wells using geologic parameters and relative permeability information available on the Arbuckle in literature. The formation was divided into ten layers, and injection wells were perforated in Layers 1 through 4 of the structure. These layers were selected based on the depth of existing injection wells in the region, some of which are intended to be remodeled for use should the project kick-off. The layers also had a good permeability distribution, thus making them suitable for large CO_2 injection at low pressure. Pressure management is important in CO_2 storage because adding large volumes of CO_2 to a reservoir without any fluid removal mechanism risks potentially rupturing cap-rock seals or generating flow through faults that would otherwise restrict flow. We also studied the formation for 50 years post-injection to monitor pressure and CO_2 plume evolution.

After 30 years of injection with three wells operating at an 1870 psi maximum bottom hole pressure constraint, the CO_2 plume covered only about 0.5% of the top layer of the North Burbank area of interest, with a significant increase in pressure from the west to the east. Fifty years after shut-in, the size of the CO_2 plumes did not significantly change. However, after injection, we saw that more CO_2 was trapped in residues than and the volume of hydrologically stored gas started to reduce, having been the dominant trapping mechanism during the 30 years of injection. We also found that the plume is sufficiently distant from the Underground Source of Drinking Water (USDW) located in the area. The simulated maximum average reservoir pressure of 1597 psi is also well below the reservoir fracture pressure range of between 2400 psi - 2700 psi.

This study provides a reference that would be useful during the potential deployment of CO_2 injection in the Arbuckle Group. This study could assist decision-making during field development in this formation as we work to ensure a sustainable future.

INTRODUCTION

Geological storage of CO_2 is an essential method of reducing atmospheric CO_2 and tackling Climate Change. Over the years, governments worldwide have sought to implement climate action policies targeting the reduction of carbon emissions in the atmosphere. Unfortunately, some of these policies are set with expectations of reducing emissions within the next two decades, thus providing an opportunity for increased CO_2 Sequestration activity worldwide.

Oklahoma has enormous potential for the geological storage of Carbon dioxide. One such potential formation is the Arbuckle formation's Saline Aquifer. Our case study was in the Osage Reservation in the Northern part of Oklahoma state. We will precisely simulate injection in the North Burbank Unit and examine the effect across Osage County.

Carbon dioxide can be stored as compressed gas, as liquid, or in a supercritical phase, depending on the condition of the reservoir. Most of the injected Carbon dioxide will be trapped in a mobile phase of the gas that is free to move laterally or migrate vertically toward the caprock. This process is known as hydrodynamic trapping (Zhang & Song, 2014). Some gas is trapped as residual gas, which occurs when formation water encroaches or invades the CO_2 plume (Mo et al., 2005). There is also a partial dissolution into the aqueous phase, otherwise known as solubility trapping, and there may be some reactions with the surrounding minerals, resulting in mineral trapping.

Hydrodynamic trapping

This refers to the trapping of CO_2 under a low-permeability caprock. CO_2 is less dense than brine and thus rises until it reaches a caprock where the capillary entry pressure is far greater than the buoyancy or hydrodynamic force. This leads to an accumulation of gas due to the vertical and lateral sealing effects. This mechanism is also called **Structural** or **Stratigraphic** trapping. This is an essential mechanism for any sequestration project because it prevents CO_2 from leaking through the caprock while other trapping mechanisms emerge. Trapping efficiency depends on the sedimentary basins' structure; variations in permeability across sedimentary basins mean that fluid flow is controlled throughout the basin. Common examples of structural traps are anticlinal folds or sealed fault blocks that exist in reservoirs that have held oil and gas for millions of years (Zhang & Song, 2014).

Residual trapping

CO_2 initially displaces brine in a co-current fashion at the start of injection, but this trend changes at the termination of injection when the fluid starts to flow counter-currently, and brine falls downwards due to its higher density. This causes a significant saturation of CO_2 to be trapped in small clusters of pores. This cluster of CO_2 is then trapped as an immobile phase. This is also known as capillary trapping.

Solubility trapping

CO_2 is soluble in water, and thus forms carbonated water when in contact with the water phase of the reservoir. This carbonated water is denser than water itself, and this process is typically known as CO_2 fingering (Alzayer et al., 2022). The solubility of the CO_2 in the formation water depends on the salinity, pressure, and temperature. This process is prolonged because CO_2 has a minimal molecular diffusion coefficient as the dissolution process is by molecular diffusion (Zhang & Song, 2014).

Mineral trapping

This is the most prolonged CO_2 trapping mechanism, and it occurs when carbonated water reacts with the formation rock to form minerals on the rock surface. This is known to be the most secure storage system (Alzayer et al., 2022), but it could also be detrimental if the reactions enhance CO_2 migration.

OBJECTIVES/SCOPE OF WORK

Objective

The objective of this work is to simulate the storage of at least 50 million metric tons of Carbon Dioxide in the Arbuckle formation of the Osage Reservation in Oklahoma while accounting for structural, residual, and solubility trapping mechanisms.

Scope of Work

The scope of this project involved:

1. Building a geological model for Oklahoma's Arbuckle Group with data from operators and literature.
2. Using modeled geology to simulate the injection of 50 million metric tons of CO2 at supercritical conditions using wells in the North Burbank Region and examine technical, social, and environmental feasibility. The total injection period was 80 years (30 years of injection and 50 years post-injection).

Relevance

This will provide more insight into the potential of the Arbuckle for CO_2 sequestration in Oklahoma and provide some proof that the process poses no serious environmental risk in the region. The sensitivity analysis will also provide us with information on what happens to injection with changes in the number of wells, maximum bottom hole pressure, and uncertainty in reservoir parameters such as permeability.

GEOLOGICAL MODEL AND RESERVOIR SIMULATION IN ARBUCKLE CASE STUDY

The area of study is the North Burbank Region, located in the Northwestern part of the Osage County Arbuckle formation (Fig 1).

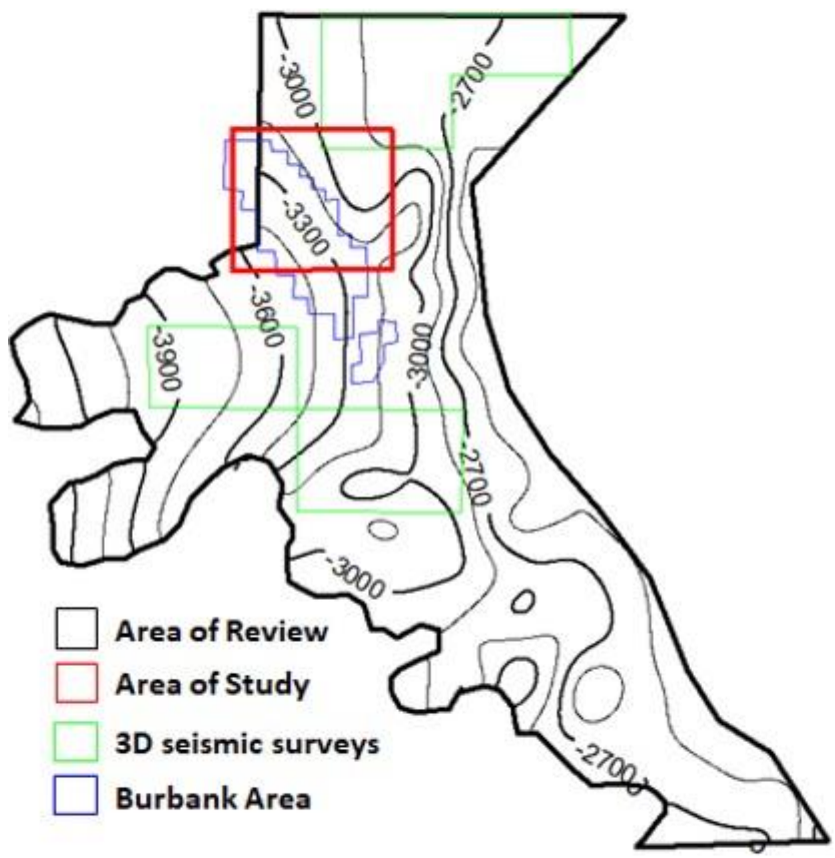


Fig 1. Simulation Area of study

The geology consists of two porous rocks of Arbuckle and Simpson Groups with two alternative caprocks/confining zones: Woodford Shale and Lower Mississippian Limestone (Fig 2). However, the proposed study focuses only on Arbuckle Group as the primary saline reservoir since it has been confirmed for commercial scale CO_2 geological storage in Kansas State (Holubnyak et al., 2017) and, historically, has been utilized for disposal water injection in the State of Oklahoma.

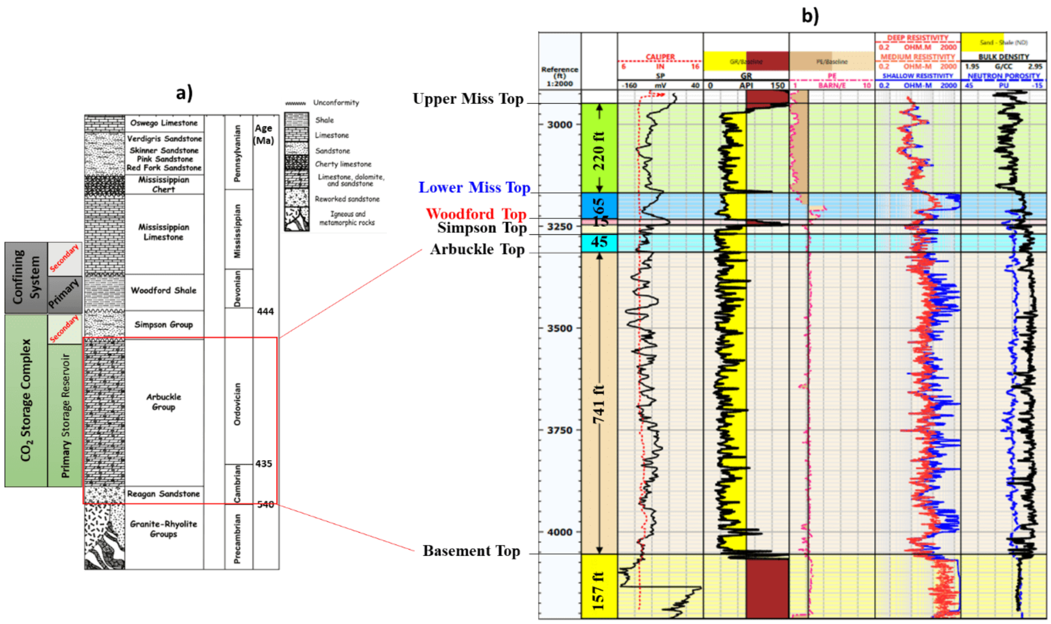


Fig 2: (a) Stratigraphic column and (b) stratigraphic type log for the Osage Reservation indicating the storage complex and confining zones for Arbuckle Group.

The Arbuckle Group in the Osage Reservation was evaluated to determine an area of study suitable for this project and for commercial storage of CO_2 considering several geological reasoning including but not limited to stratigraphic thickness, the minimum depth required for supercritical CO_2, storage capacity, and other factors such as coverage by existing 3-D seismic surveys. Some of the available datasets include well logs from 124 pre-existing Arbuckle disposal wells (distributed in the whole Osage Reservation), 5 Arbuckle core samples, a dedicated test well for this project, water disposal injection data, and 9 seismic surveys covering 372.85 square miles of the Osage Reservation.

The Arbuckle Group is associated with shallow shelf carbonates and was deposited during the Middle Cambrian to Late Ordovician age. Also, the Arbuckle Group has been deposited with an aerial extent that underlays most of Oklahoma state and adjacent states (Ching & Friedman, 2000). The lithology of the Arbuckle Group is primarily dolomite and limestone units (Rottmann et al., 2015).

The Arbuckle Group is affected by extensive karstic features. Solution-collapse brecciation developed, especially in the upper part of Arbuckle, during repeated subaerial exposure of north-south marine regression sequences (Wilson, 1994). These karst features are prominent factors controlling the matrix porosity, which usually provides a significant amount of porosity and permeability (Milad et al., 2018).

Fig 3 below shows the distribution of the parameters upon which our simulation model was based:

- Reservoir fracture pressure 2400 psi - 2900 psi.
- Reservoir average permeability 200mD

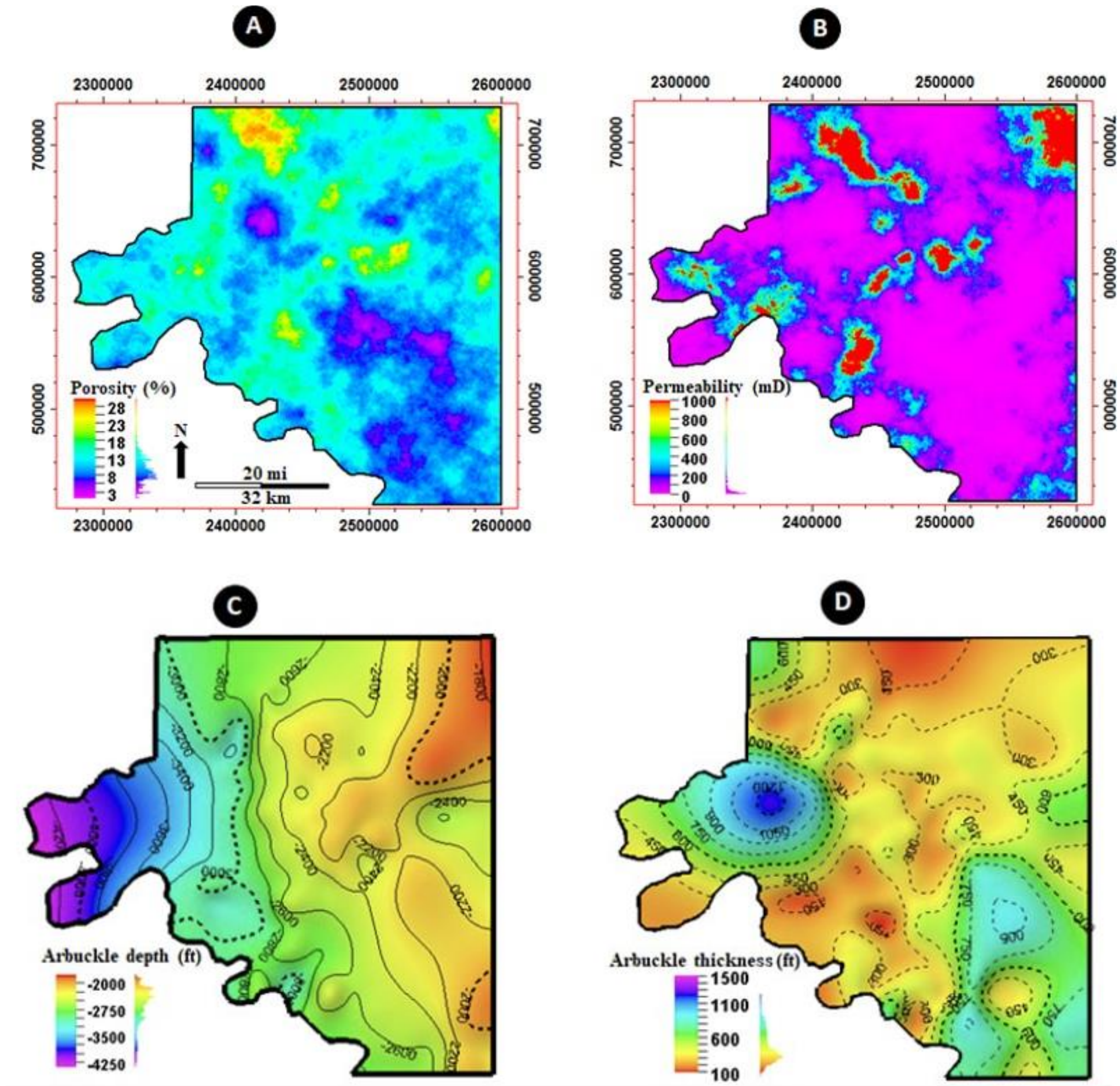


Fig 3. Arbuckle group map of (a) Porosity, (b) Permeability, (c) Depth, (d) Thickness

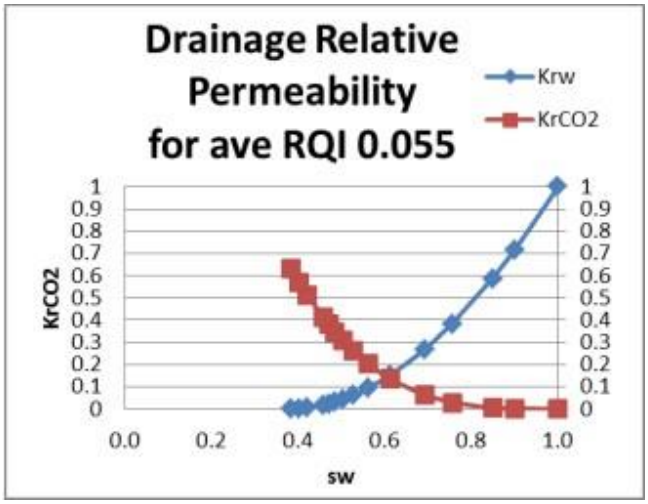
These values were obtained from a combination of literature and work done by operators to characterize this formation.

CMG GEMS, using Peng-Robinson equation of state, was used to simulate the injection of 50 million Metric Tons of CO_2 in the Arbuckle within a 30-year period using 3 injection wells at a maximum bottom-hole injection pressure of 1870. We considered all known CO_2 trapping mechanisms except mineralization trapping. Mineralization by CO_2 injection takes hundreds to thousands of years to occur and will, therefore, not be a factor in this case study. We, however, modeled hydrologic, residual, and solubility trapping mechanisms for this system. The reservoir was also simulated for 50 years after the end of the injection.

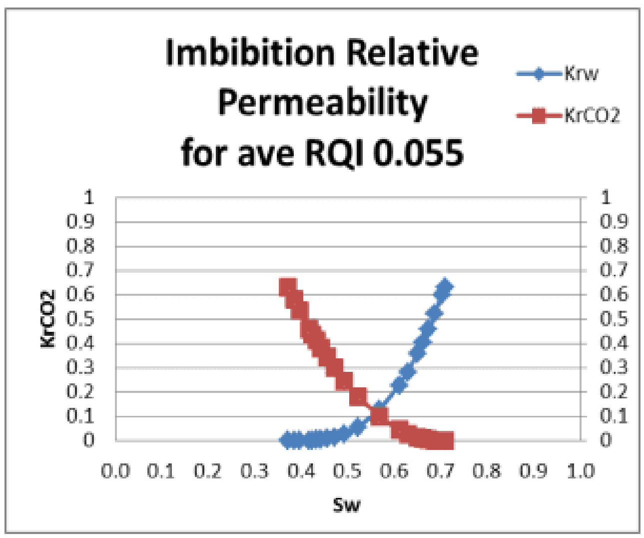
Initial Pressure and Temperature for this simulation were 1500psi at 3500ft and 120 deg Fahrenheit:

Fig 4 shows the Drainage and Imbibition relative Permeability curves as obtained from work done by Fazelalavi in 2015 to determine relative permeability in the Arbuckle. Note that the RQI for our area of interest was calculated based on a core analysis carried out in our labs in Norman, Oklahoma.

$$RQI = 0.0314\sqrt{Permeability/Porosity}$$



(a)



(b)

Fig 4. Drainage and Imbibition Relative Permeability Curve for Arbuckle (Fazelalavi, 2015)

We used a very fine grid with dimensions 647 x 601 x 10. The wells were perforated in the higher permeability region (layers 1 to 4) with an average perforation length of 120 ft of the reservoir to maximize injectivity. These wells were chosen to closely match existing water injection wells in the region that have been used for water disposal over the years. The X-Y Coordinates are:

- Well 1: X = 2372710 ft, Y = 651885 ft
- Well 2: X = 2380700 ft, Y = 655382 ft
- Well 3: X = 2375210 ft, Y = 656880 ft

The operating constraint was set to be the maximum injector bottom hole pressure across the three injection wells. The number of injection wells and average permeabilities was also varied to meet the set target of 50 million metric tons.

RESULTS AND DISCUSSION

After extensive simulation and sensitivity analysis, we ended up with a model with a Maximum injection bottom hole pressure of 1870 psi and a fixed average permeability of 200 mD with 3 wells.

# of Injection wells	Maximum Bottom hole Pressure (psi)	Cumulative Injection (Million MT)	Permeability (mD)
3	1870	51	200
1	2000	3	50
16	2000	48	50
4	2000	7.5	50
3	2000	84	250
3	2200	125	300

Table 1. Sensitivity of Cumulative Injection rate to Number of Injection wells and Maximum injection Bottom Hole Pressure

Lower average permeability resulted in the need for many more wells and a higher maximum injection bottom hole pressure in order to come close to the 50 million metric tons required. Fewer wells will result in lower volumes injected, and higher injection bottom hole pressure means more volume. We capped the sensitivity on maximum bottom hole pressure at 2200 to ensure we stay within 90% of the lower bound of reservoir fracture pressure (2400 psi) as estimated by the operator.

Figs 5 and 6 show the pressure and CO_2 plume evolution for the 30 years of injection and in the 50-year period after. Figure 7 shows the location of the Underground Source of Drinking Water (USDW) in Osage county in relation to the overall areal extent of the CO_2 plume.

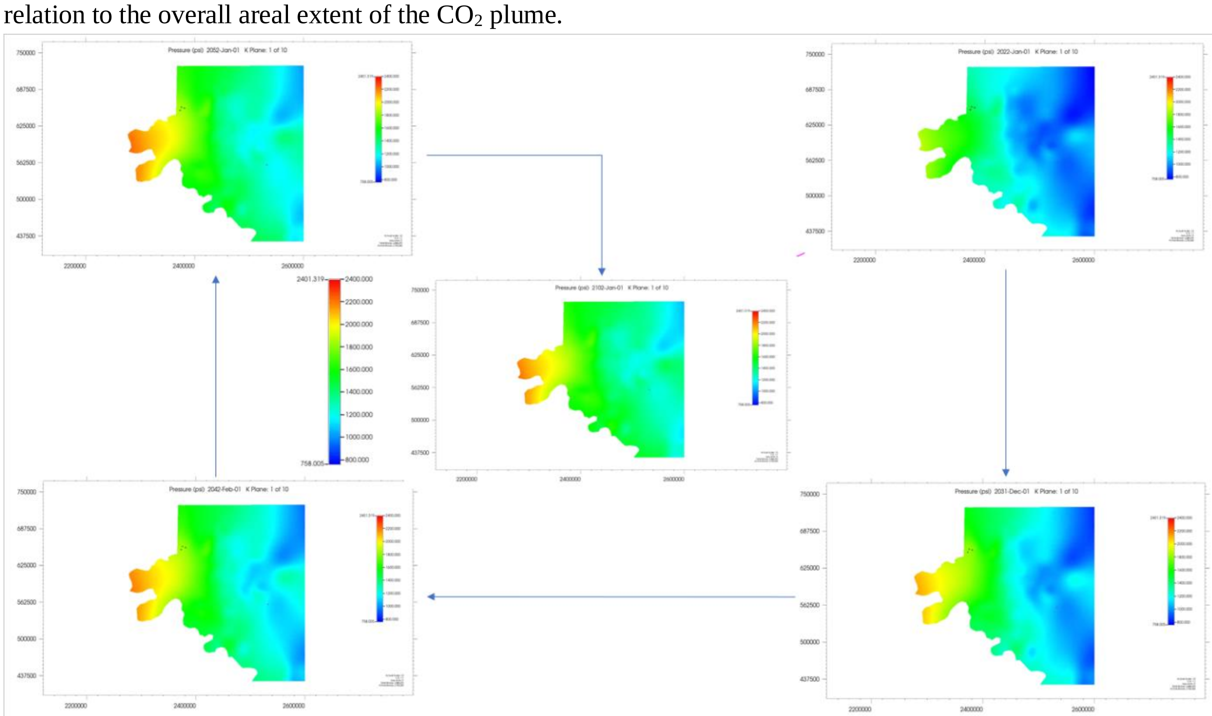


Fig 5. Pressure evolution over 80 years; injection stopped after 30 years.

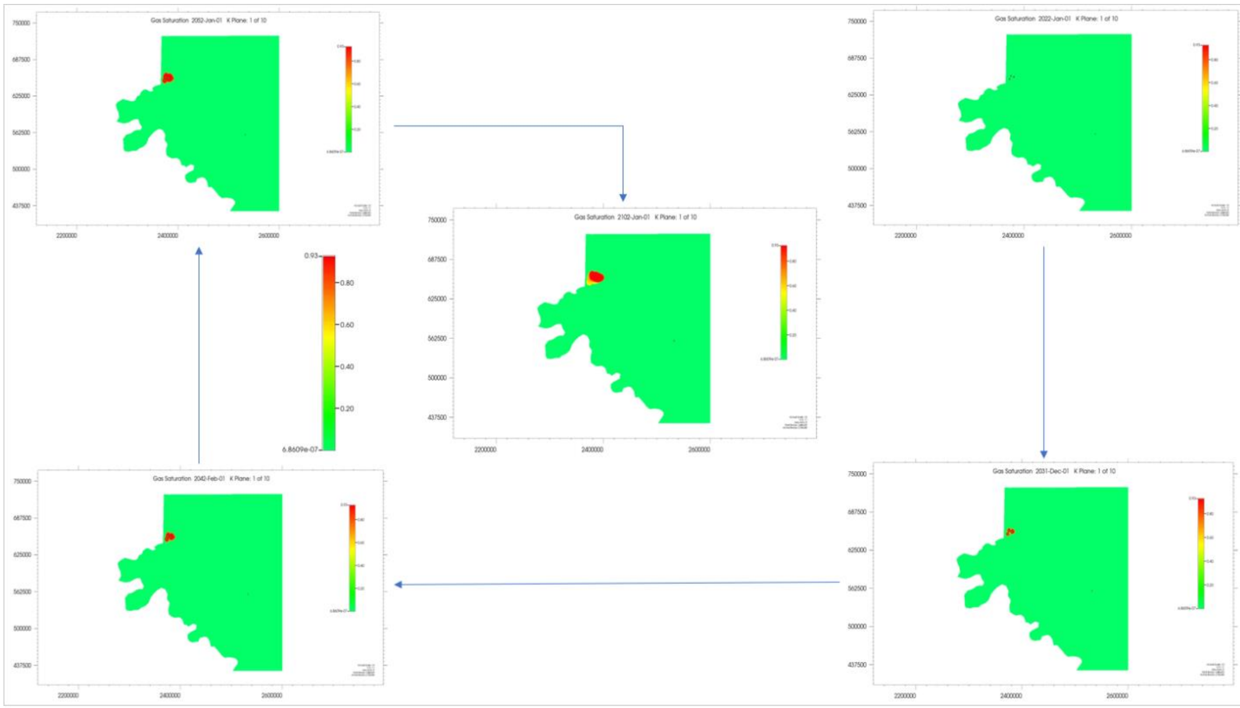


Fig 6. Plume evolution over 80 years; injection stopped after 30 years.

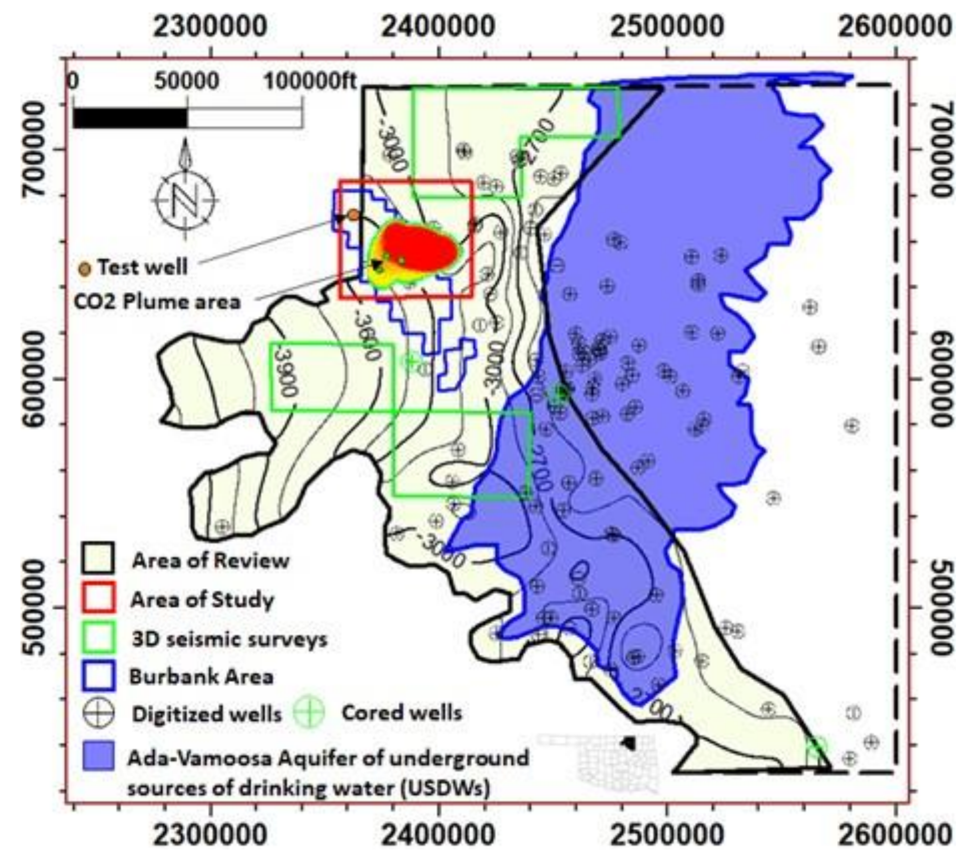


Fig 7. Underground sources of drinking water (USDWs) in relation to the entire anticipated areal extent of the CO_2 plume after 80 years

From Fig 5, we see that as more CO_2 is being injected into the formation, pressure increases in the reservoir from the west to the east. This is indicative of sufficient reservoir mobility and connectivity across the reservoir to avoid pressure build-up in the injection site.

Fig 6 and Fig 7 show the CO_2 plume evolution and the final areal extent of the plume after injection. We see that the plume is firmly within the north Burbank area of study and does not move much in the 50 years after injection. The plume covers only about 0.5% of the Osage Arbuckle, and we also see in Fig 7 that the plume is at least 50,000ft from the Underground Source of Drinking Water in Osage County, thus indicating that there is little to no risk of underground water contamination by injecting CO_2. We also successfully simulated the injection of circa 1,000,000 MMscf (51 million metric tons) of CO_2, meeting the specified target injection as seen in Fig 8 with the maximum average reservoir pressure at 1597 psi.

Fig 8 shows the average pressure of the reservoir and the cumulative injection over time.

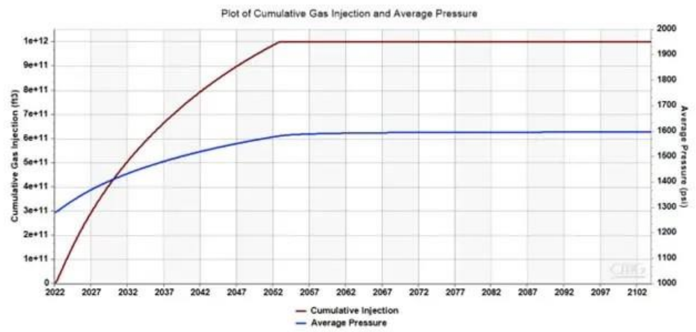


Fig 8. Cumulative Gas Injection (scf) and Average Reservoir Pressure (psi) over time.

Fig 9 gives a plot of the injection rate over time into the reservoir as simulated with a maximum injection rate at six months after the commencement of injection, after which the injection rate declines.

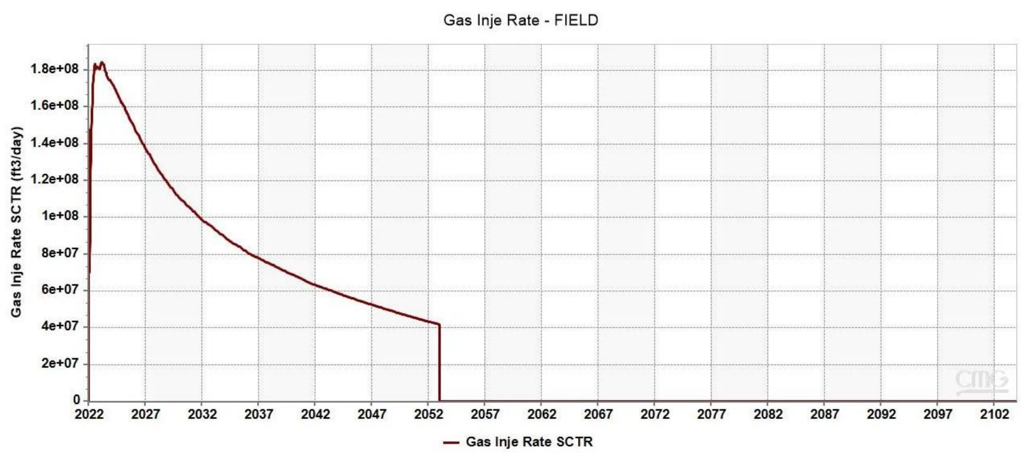


Fig 9. Gas Injection rate (SCF/day) over time

Fig 10 shows the volume of CO_2 trapped by the different mechanisms in the reservoir. As expected, most of the gas is trapped hydrologically. Some of the gas dissolves in the saline water in the aquifer, and on completion of the injection, gas is stored in small clusters as residues due to the more significant density of the brine relative to the CO_2. The onset of residual trapping leads to a decline in the moles of CO_2 trapped hydrologically, and in the end, we have more gas stored in residual pores than dissolved in the brine.

Fig 10. CO2 Trapped by Different mechanisms

CONCLUSION

The following conclusions may be drawn from our work:

1. We can successfully inject 50 million metric tons of CO_2 into the Arbuckle using three wells operating at 1870 psi bottom hole pressure in the North Burbank Region, provided the average permeability in the reservoir is about 200mD. Lower average permeability will require either more injection wells or higher bottom-hole injection pressure.
2. Injection in this region poses no environmental justice issues as the plume is sufficiently distant from any underground sources of drinking water, and average pressures are well below the reservoir fracture pressure range.
3. Hydrologic trapping is the dominant trapping mechanism during the injection. After injection, residual trapping becomes dominant, and the volume of gas stored hydrologically starts to drop.

FUTURE WORK

As part of possible future work to be done on this project, it would be beneficial to investigate the geochemical side of simulating CO_2 injection in this formation. In addition, mineralization trapping should be modeled for up to thousands of years after the termination of injection. Further sensitivity should also be done on reservoir properties, including porosity and more permeability values, to account for the uncertain nature of reservoirs.

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