

Estimates of Permeability and CO₂ Storage Capacity at the Patterson Field Using Analysis of City of Lakin Wastewater Injection Well Characteristics

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1. Introduction

Geological modeling and numerical simulation studies for the Patterson site are based on reservoir properties (particularly permeability) inferred from well logs, which did not consider important features of carbonate rocks, such as fractures and vugs, and thus systematically underestimate injectivity and storage capacity. The city of Lakin wastewater injection well (KS-05-093-002) is located in very close proximity to the Patterson site (Kearny County) and offers a great example of an active injection well in the area (Figure 1). Data from this well can be used for injectivity analysis to obtain reservoir-scale Arbuckle properties, compare with nearby wells, history match the pressure increase, and ultimately determine the CO₂ storage capacity, as described in this paper.

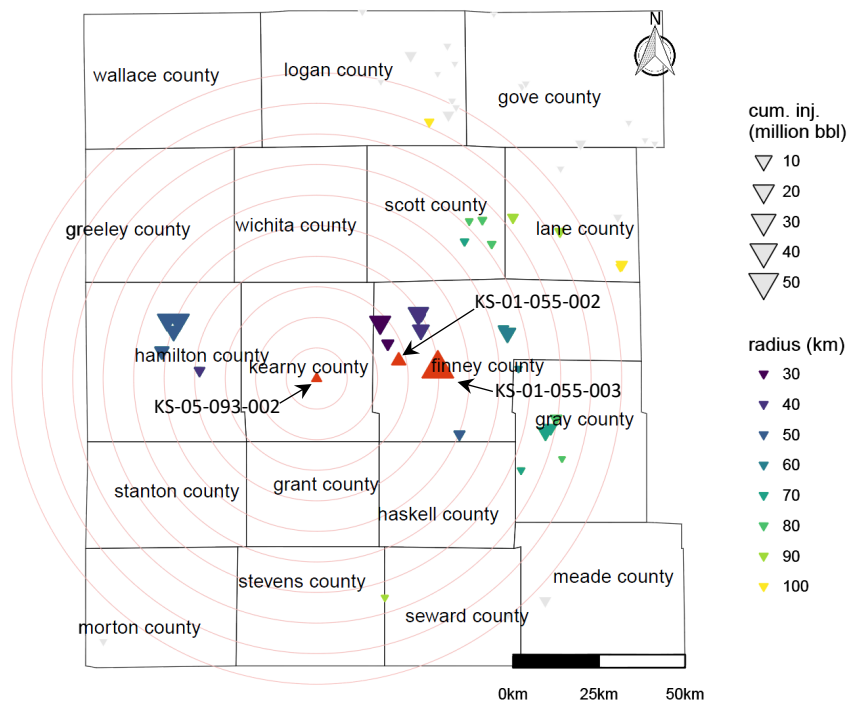


Figure 1: Wells injecting into the Arbuckle aquifer near the Patterson area (Kearny County) and their lifetime injection volumes. Red upward triangles show Class I (or V) wells operated by the Kansas Department of Health and Environment. Downward triangles show Class II wells operated by the Kansas Corporation Commission; the color of the triangle indicates the well’s distance from KS-05-093-002 (circles show 10 km increments). Note that few wells inject into the Arbuckle in the Patterson area. Other nearby Class I wells for which more data are available (KS-01-055-002 and KS-01-055-003, labeled as red upward triangles) are located in Finney County.

2. Injectivity analysis

The City of Lakin wastewater injection well is a class V well that operates in a similar manner to Class I wells that inject wastewater ($\rho \approx 1020 \frac{kg}{m^3}$ density and ≈ 3500 mg/l salinity) into the Arbuckle formation under gravity feed. Table 1 summarizes the characteristics of the Arbuckle Group around this well. Figure 2 and Table 2 summarize the current and projected maximum possible injection volumes into this well. The projected maximum injection volume for this well ($\approx 0.26 \frac{Mt}{year}$) is based on the maximum recorded injection rate (originally reported in gallons/minute) under gravity drainage.

Table 1: Arbuckle properties based on KS-05-093-002

Property	Thickness (m)	Temperature (°C)	Pressure (MPa)	Permeability (md)	Porosity
	183	43	11.82	473–2,870	0.12

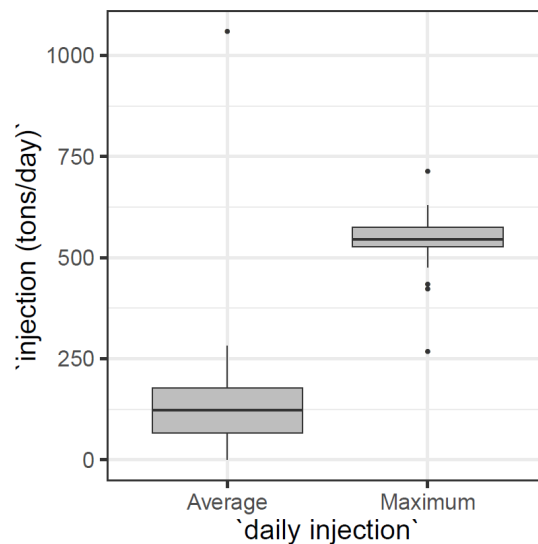


Figure 2: Wastewater injection volumes ($\rho \approx 1020 \frac{kg}{m^3}$ density and ≈ 3500 mg/l salinity) into KS-05-093-002. The maximum daily injections are based on maximum recorded injection rates.

Table 2: Summary of injection volumes into KS-05-093-002

Injected wastewater ($\rho = 1000 \frac{kg}{m^3}$)	2015	2016	2017
cumulative injected (Mt/year)	0.0233	0.0626	0.0342
Max injected rate (ton/day)	714	629	623
Projected max possible based on max rate (Mt/year)	0.260	0.230	0.227

Although injection in the well occurred under gravity feed, the injection pressure is provided by the column of water in the well. The static fluid level is $\approx 1,215$ m (or 12.15 MPa) above the open hole (which is a depth of $\approx 1,790$ m or ≈ 30 m below the top of the Arbuckle Group) and the formation pressure is ≈ 11.82 MPa; thus, the well is injecting under $\Delta p_{inj,min} \approx 0.33$ MPa (≈ 50 psi) when injecting at low rates. Assuming the well almost fills up when the injection is occurring under the reported maximum rates (fluid level data are not available), a pressure gradient of $\Delta P_{inj,max} \approx 6.05$ MPa (880 psi) is needed to achieve the maximum projected annual rates into the Arbuckle. In reality, however, the maximum pressure is always lower than this value because the well never fills up while injecting at the maximum rate.

Assuming there are six wells for injecting 50 Mt CO₂ in 25 years (2 Mt/year), as required by the Department of Energy, and the Arbuckle Group has to accept 50% of all injections (40% Osage and 10% Viola, based on numerical simulations), the injectivity requirement for the Arbuckle Group is 0.17 Mt/year. The CO₂ project requires 35% less injection volume than the projected maximum possible injection volume into the Lakin well (i.e. ≈ 0.26 Mt/year). Additionally, the Kansas Department of Health and Environment requires that injection into well KS-05-093-002 should not exceed 1,135 m³/day (0.4 Mt/year) as a criterion for the CO₂ project.

3. Reservoir-scale Arbuckle properties

Figure 3 shows the injection volumes into the Arbuckle aquifer around KS-05-093-002. The rate of injection within 25 km of the well is less than 0.1 Mt/year (the CO₂ project roughly requires 0.17 Mt/year per well into the Arbuckle and 1 Mt into all six wells, which are less than 25 km apart). The total injection into this aquifer since 2000 (17 years) within 35 km of the well is less than 4.5 Mt (the CO₂ project roughly requires 17 Mt injection into the Arbuckle within 17 years). Figure 3 shows an advantage for injecting CO₂ in western Kansas, specifically the Patterson site, because it has low historical and currently active injection volumes. This figure, however, also shows a disadvantage for the Patterson site in that injecting 50 Mt of mass into the Arbuckle in western Kansas is a completely new experiment for both injection rate and cumulative injection with an order of magnitude higher than all previous injections, thus requiring a detailed study of all its aspects (induced seismicity, leakage, etc.).

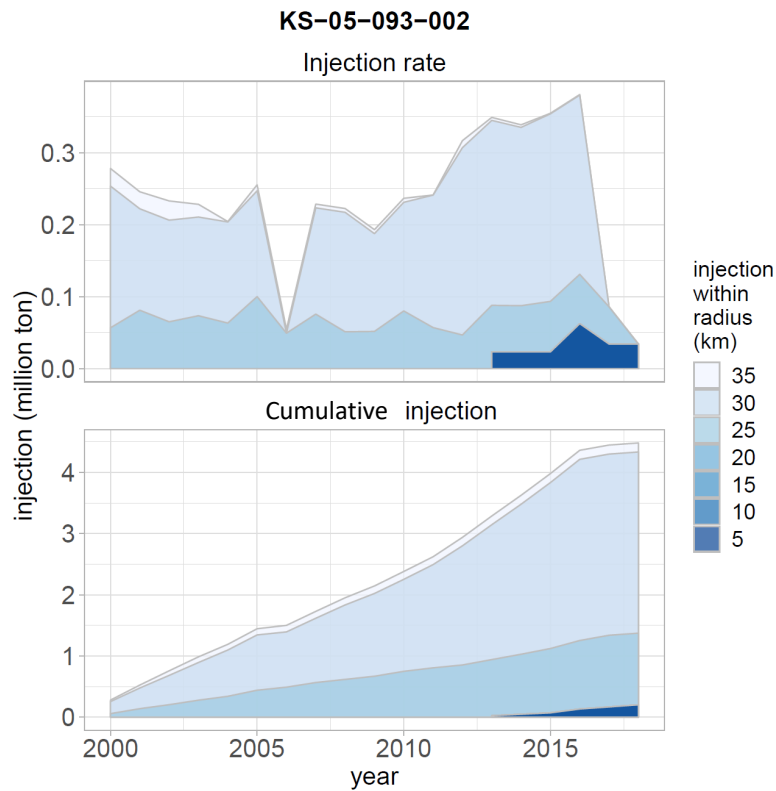


Figure 3: Wastewater injection (in million tons) in the vicinity of KS-05-093-002. The cumulative wastewater injected within 35 km of KS-05-093-002 is <4.5 million tons (since 2000).

Figure 4 shows the injection into well KS-05-093-002 (in million barrels), its static fluid level (SFL), and pressure. Injection volumes are available for 2015, 2016, and 2017 and pressure/SFL data are available for 2013 and 2018. The formation pressure has increased by 0.05 MPa, while the SFL has dropped 12 meters after five years. For the history matching analysis, the 2015 injection volume is used for 2013 and 2014, and the 2017 injection volume is used for 2018 (i.e., assumed the same as). Similarly, 2018 pressure and SFL data are used for 2017. These assumptions are deemed to reasonably compensate for limited data.

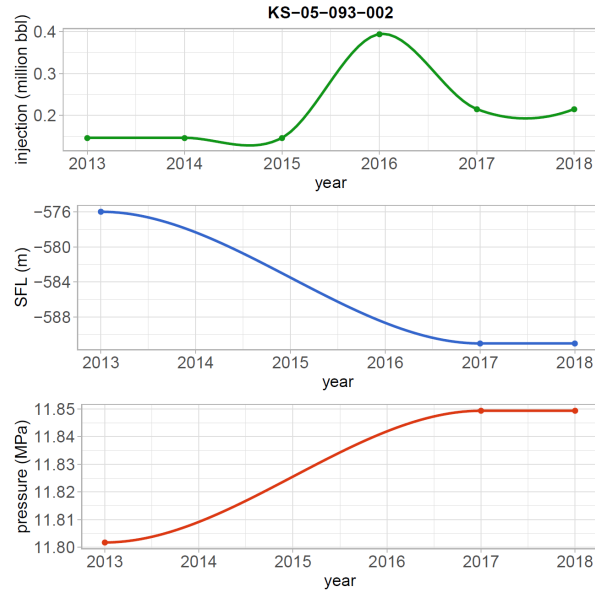


Figure 4: Injection, pressure, and SFL data for KS-05-093-002. The 2015 injection volume is used for 2013 and 2014; the 2017 injection volume is used for 2018; and the 2018 pressure and SFL data are used for 2017. These assumptions are deemed reasonable to compensate for limited data.

Figure 5 summarizes the Arbuckle properties from the two available fall-off measurements (2013 and 2018). The two permeability values interpreted for this well are 2,870 md for 2013 and 473 md for 2018. However, a close analysis of 2013 pressure data shows that this permeability was not correctly interpreted. With only one permeability data point available, comparison with data from nearby wells yields a better constraint on the permeability in the area.

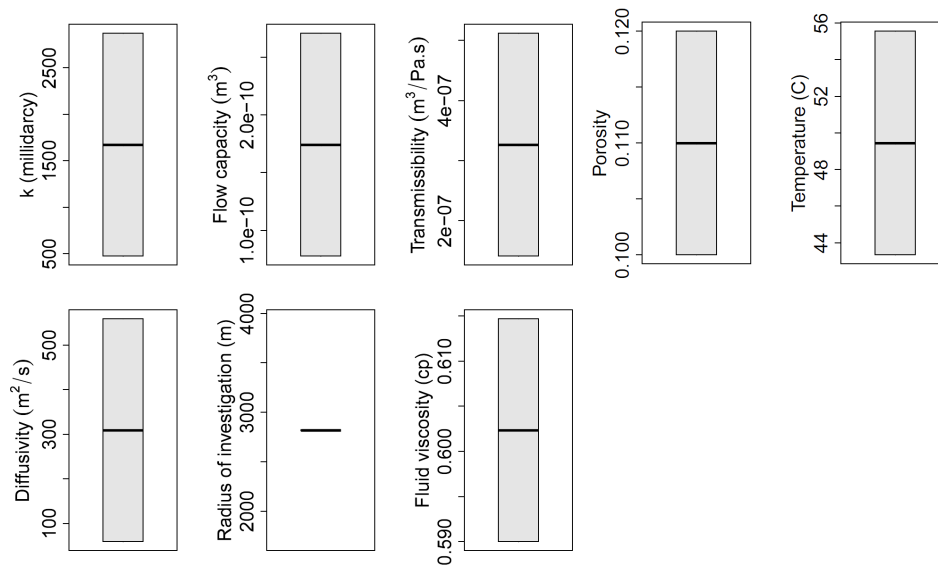


Figure 5: Arbuckle properties inferred from fall-off test on KS-05-093-002. Note that only two data points are available for this well. The solid line shows the mean.

4. Comparison with data from nearby wells

Because of limited data for KS-05-093-002, data from nearby Class I wells (KS-01-055-002 and KS-01-055-003) can be used for comparison. Figure 6 summarizes well test data for two Class I wells with more active injection: KS-01-055-002, located in western Finney County, and KS-01-055-003, located in the center of Finney County. Locations of both wells are shown in Figure 1. The permeability measurements for 15 fall-off tests for KS-01-055-002 consistently indicate that the permeability of this well is less than 200 md. The permeability measurements of 24 fall-off tests (since 1995) for well KS-01-055-003 indicate that the permeability of this well is less than 400 md. These data show that the 2018 Arbuckle permeability measured for KS-05-093-002 (473 md) is probably more representative of the Patterson site than the 2013 permeability (2,870 md). In addition, a close look at the fall-off interpretation for KS-05-093-002 during 2013 shows that the Arbuckle thickness used in the well test analysis (and resulting in permeability of 2,870 md) is incorrect.

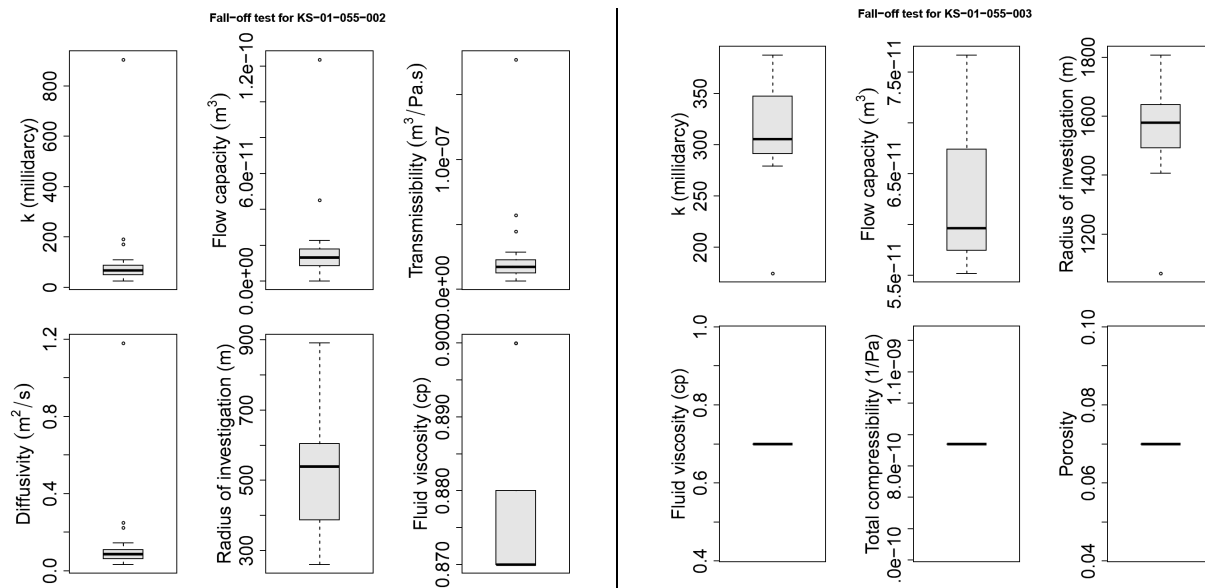


Figure 6: Reservoir properties obtained using fall-off measurements for well KS-01-055-002 (left) and for well KS-01-055-003 (right). Both results indicate <500 md permeability for the Arbuckle in western Kansas. These data indicate that the 2018 Arbuckle permeability measured for KS-05-093-002 (473 md) is probably more representative of the Patterson site than the 2013 permeability (2,870 md).

5. History matching pressure increase

History matching is often used to obtain more accurate reservoir-scale properties than well tests, because the well test interpretations are limited to the radius of investigation (3 km for KS-05-093-002, Figure 5). However, due to the limited pressure data (2–3 points) for KS-05-093-002, fall-off results are probably more reasonable. Figure 7 shows the history match results, the interpreted diffusivity and transmissibility, and the associated mean square error for KS-05-093-002 (two recorded and one assumed pressure data, Figure 4). History matching connects the injection volumes into the well and its vicinity to the amount of observed pressure increase using simple analytical solutions (2-D transient solutions). The history match results indicate low reservoir-scale diffusivity and transmissibility for the Patterson site, which indicate low permeability (less than 100 md) in the Patterson area. Nevertheless, the results of history matching are uncertain because many curves (realizations) can match limited data points.

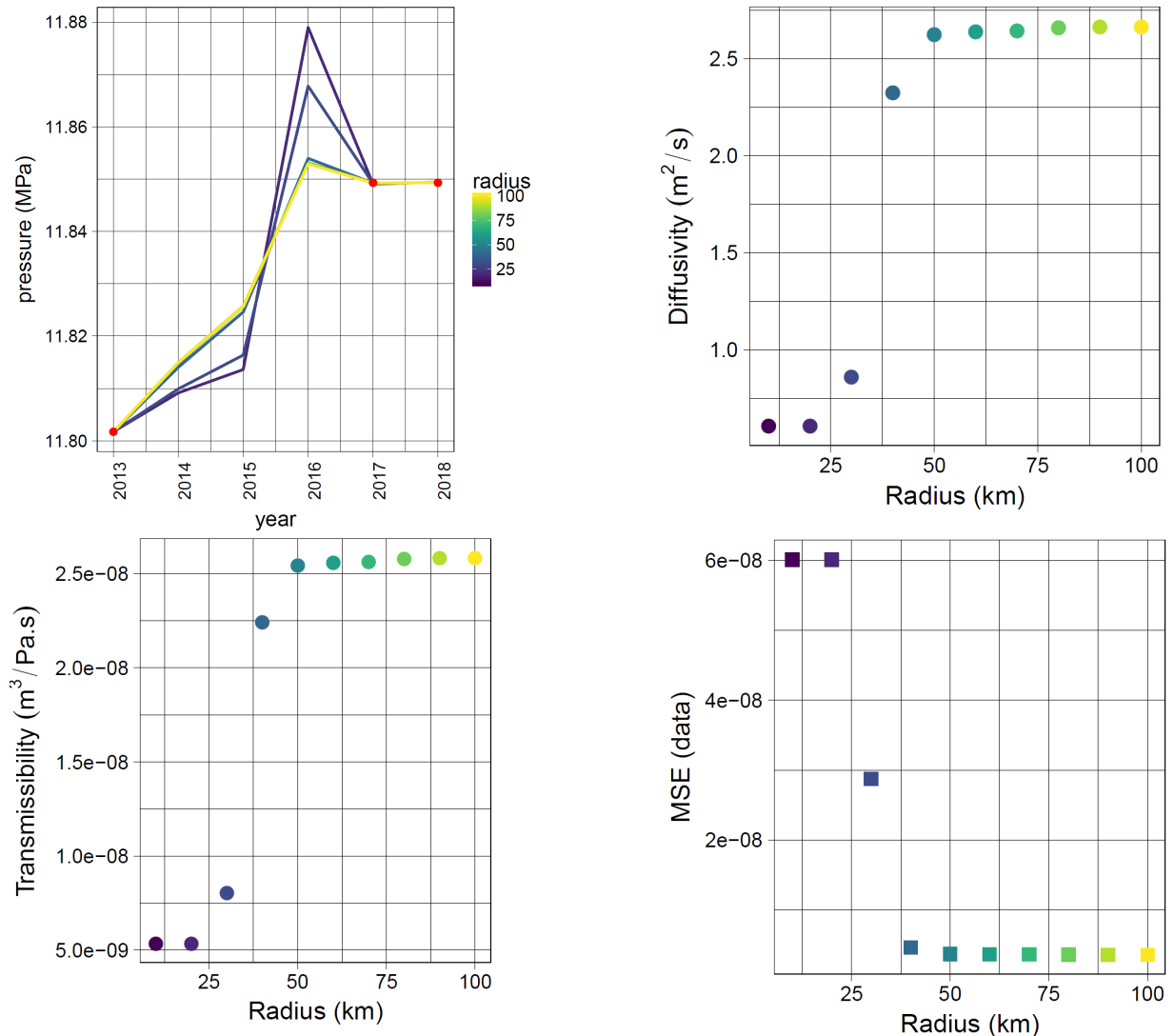


Figure 7: History matching pressure by calibrating diffusivity. The diffusivity and transmissibility obtained from history matching are very low, indicating the Arbuckle in the Patterson area has low permeability, porosity, and compressibility. However, the history matches are uncertain because limited pressure data are available.

6. CO₂ storage capacity

If we consider the reservoir-scale permeability of 473 md for the Patterson site, the CO₂ storage capacity of the site can be determined following the calculations described in Nordbotten et al. (2005), Okwen et al. (2010), and Ringrose (2018). Supercritical CO₂ viscosity and density at reservoir temperature (43 °C) and pressure (11.82 MPa) are 628.5 kg/m³ and 50.15×10^{-6} Pa. s, respectively. The Patterson area is 129.5 km² (50 square miles) with a thickness of 173.7 m (well logs data). The residual brine after CO₂ flood is assumed to be $S_r = 0.3$. The in-situ brine has an end-point relative permeability of 1, viscosity of 0.6×10^{-3} Pa. s, and density of 1,020 kg/m³ (Figure 5). CO₂ is assumed to have a low end-point relative permeability of $k_{r,c} = 0.2$. From Table 2, $Q_{well_{max}} = 0.26$ Mt/year (8.24 kg/s), and we have CO₂ density as 628.5 kg/m³; thus, the CO₂ injection volume ($Q_{well_{max}}$) becomes 13.1×10^{-3} m³/s. The storage efficiency is defined as the ratio of CO₂ stored to the available pore volume:

$$\epsilon = \frac{V_{injected}}{V_{formation}} = \frac{Q_{well}t}{\phi B \pi (r_{max})^2}$$

Interplay between viscous and buoyancy forces determines the storage efficiency. Thus, storage efficiency depends on permeability, porosity, mobility ratio between the displacing and displaced phases, and residual water saturation in the formation after CO₂ flood. The brine and CO₂ mobility and their ratio depend on the end-point relative permeability of brine (assumed as 1) and CO₂. For the particular case assumed here, the mobility ratio is calculated as follows:

$$\lambda_b = \frac{k_{r,b}}{\mu_b} = \frac{1}{0.6 \times 10^{-3}} = 1.67 \times 10^3 \frac{1}{Pa \cdot s}$$

$$\lambda_{CO_2} = \frac{k_{r,CO_2}}{\mu_{CO_2}} = \frac{0.2}{50.15 \times 10^{-6}} = 3.99 \times 10^{10} \frac{1}{Pa \cdot s}$$

$$\lambda = \frac{\lambda_{CO_2}}{\lambda_b} = \frac{4}{1.7} = 2.39$$

In practice, however, permeability, porosity, residual water saturation, and end-point relative permeability of CO₂ are uncertain. Thus, a range of plausible values for these parameters is considered using well test and well log (porosity only) data (Figure 8) to calculate the uncertainty in the CO₂ storage capacity and maximum CO₂ plume radius around the well (note that for all studies, the total sampling frequency N is assumed to be 1,000—e.g., a frequency of 200 means 0.2 probability for a value). The gravity number, Γ , representing gravity force is defined as:

$$\Gamma = \frac{2\pi\Delta\rho g k \lambda_b B^2}{Q_{well}} = \frac{2 \times 3.14 \times (1020 - 628.5) \times 9.8 \times (473 \times 10^{-15}) \times 1.7 \times 10^3 \times 183^2}{13.1 \times 10^{-3}} = 47.36$$

Nordbotten and Celia (2006) show storage efficiency is a nonlinear ODE function of χ_{max} (a non-dimensional variable representing r_{max}), which includes both gravity number and mobility ratio.

$$\epsilon = \frac{2(1 - S_r)}{\chi_{max}}$$

Okwen et al. (2010) solved this nonlinear ODE for various values of Γ and λ and used regression to find an approximation equation:

$$\chi_{max} \approx (0.0324\lambda - 0.0952) \Gamma + (0.1778\lambda + 5.9682) \Gamma^{\frac{1}{2}} + 1.6962\lambda - 3.0472$$

$\chi_{max} = 44.18$ for the assumed values. Thus, the storage efficiency for the assumed case is:

$$\epsilon = \frac{2(1 - S_r)}{\chi_{max}} = \frac{2 \times (1 - 0.3)}{44.18} = 0.032$$

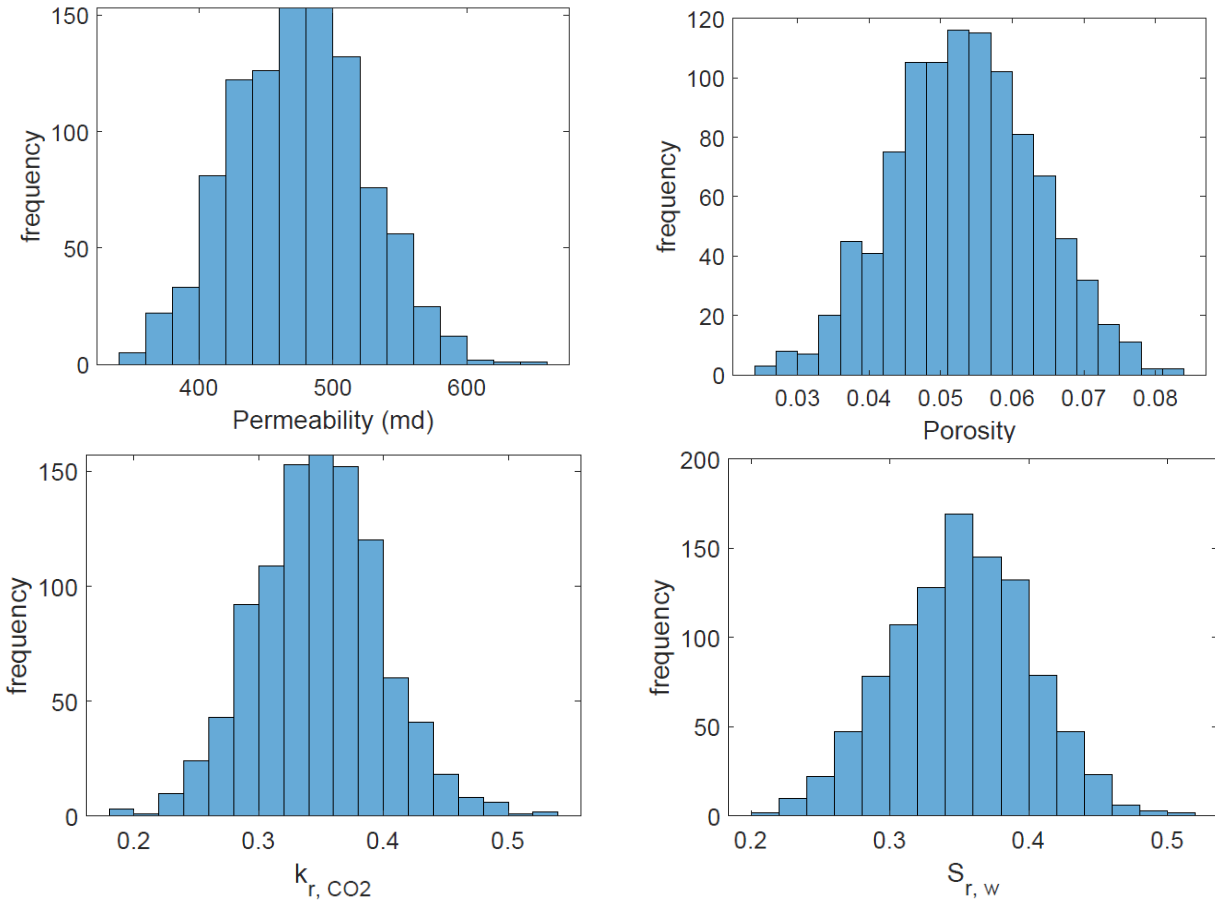


Figure 8: Distribution of the parameters used for assessing the Arbuckle storage in the Patterson area. For all studies the total sampling frequency N is assumed to be 1,000 (e.g., a frequency of 200 means 0.2 probability for a value).

Figure 9 shows the mobility ratio and storage efficiency for the range of parameters assumed for the Arbuckle aquifer in the Patterson area. The low storage efficiency found in Figure 9 is typical of carbonate shelf rocks consisting of limestone and dolomite (Goodman et al., 2011; Okwen et al., 2014).

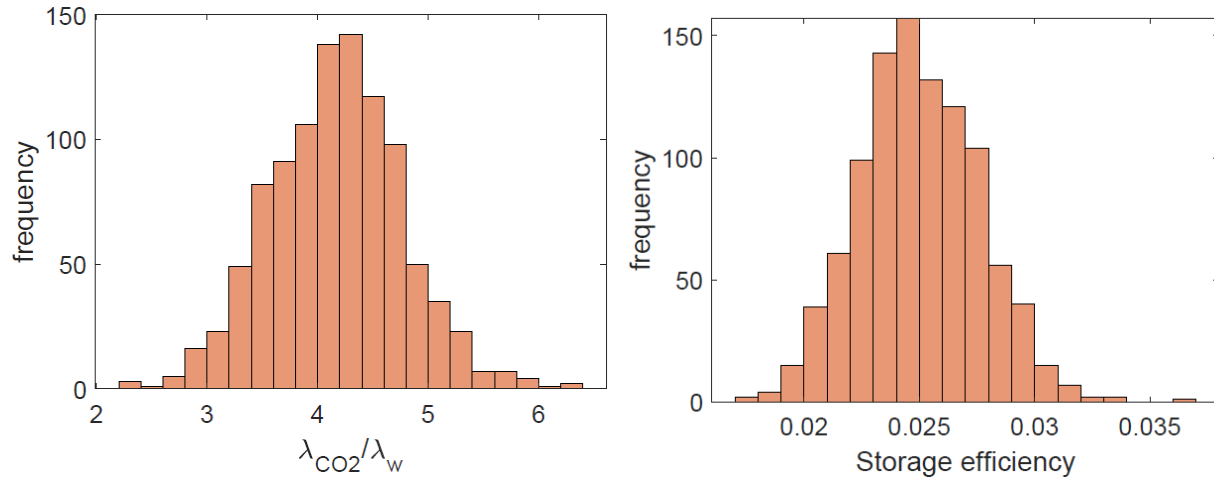


Figure 9: The mobility ratio and CO₂ storage capacity efficiency obtained for the Arbuckle aquifer in the Patterson area. λ stands for mobility.

Considering an area of 129.5 km² for the Patterson site and an average porosity of 5.4% (average obtained from well logs), the storage capacity for the Patterson site can be calculated as follows:

$$V_{pore} = A \times B \times \phi = 129.5 \times 10^6 \times 173.7 \times 0.054 = 1.2 \times 10^9 \text{ m}^3$$

$$\text{Storage capacity} = V_{pore} \times \epsilon \times \rho_{CO_2} = 1.2 \times 10^9 \times 0.032 \times 628.5 = 24.1 \text{ million ton}$$

We can now calculate the radius of the CO₂ plume after 25 years.

$$r_{max} = \sqrt{\frac{Q_{max}t}{\phi B \pi \epsilon}} = \sqrt{\frac{13.1 \times 10^{-3} \times 25 \text{ years} \times \frac{3.154 \times 10^7 \text{ sec}}{\text{year}}}{0.054 \times 173.7 \times 3.14 \times 0.032}} = 3197 \text{ m} = 3.197 \text{ km}$$

Thus, for the assumed values, the CO₂ plume reaches a radius of 3.197 km within the Arbuckle after 25 years of injection.

Figure 10 shows the Tornado sensitivity analysis for the storage capacity of the Patterson site. This figure shows that storage capacity is mostly controlled by porosity; thus, a good characterization of porosity determines an overall storage capacity. The porosity used here is based on well log measurements since well test porosity is often assumed. Note that increases in permeability, residual water saturation, and CO₂ end-point relative permeability decrease the storage capacity because these variables increase the radius of the CO₂ plume. Arbuckle permeability creates a tradeoff between injectivity, storage capacity, and pressure increase. High permeability increases injectivity and lowers the pressure increase by diffusing the injected fluid into an extended area, hinders brine movement into the basement, and decreases the chance of induced seismicity and caprock damage. High permeability, however, increases the radius of CO₂ plume, lowers the storage capacity by extending the plume out of the designated structural trap of the Patterson site through possible flow pathways, and increases the leakage risks through old wells, faults, and caprock seal. Although permeability and porosity are often related, detailed characterization of porosity using well logs is useful because high porosity improves storage capacity (Figure 10) and injectivity.

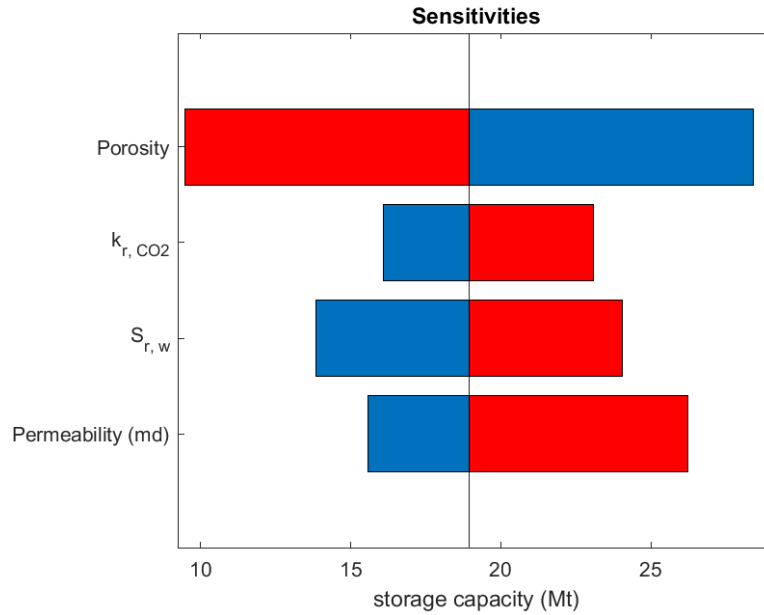


Figure 10: Tornado sensitivity analysis for the storage capacity of the Patterson site (blue indicates positive correlation and red indicates negative correlation). Storage capacity is mostly controlled by porosity and an increase in permeability, residual water saturation, and CO₂ end-point relative permeability decreases the storage capacity because these variables increase the CO₂ plume radius.

Figure 11 shows the uncertainty in the storage capacity and maximum CO₂ plume radius based on the calculated mobility ratio and storage efficiency. Combining Figures 10 and 11 shows that only in a higher porosity and lower permeability situation ($S_{r,w}$, k_{r,CO_2}) can the Arbuckle storage capacity meet the DOE 25 Mt capacity requirement. Current analysis considers 50% storage capacity for the Arbuckle (as is shown by previous numerical simulations and National Risk Assessment Partnership CO₂-SCREEN analysis) and assumes that the Viola and, in particular, the Osage formations will meet the respective requirements of 10% and 40% of the total storage capacity for the project.

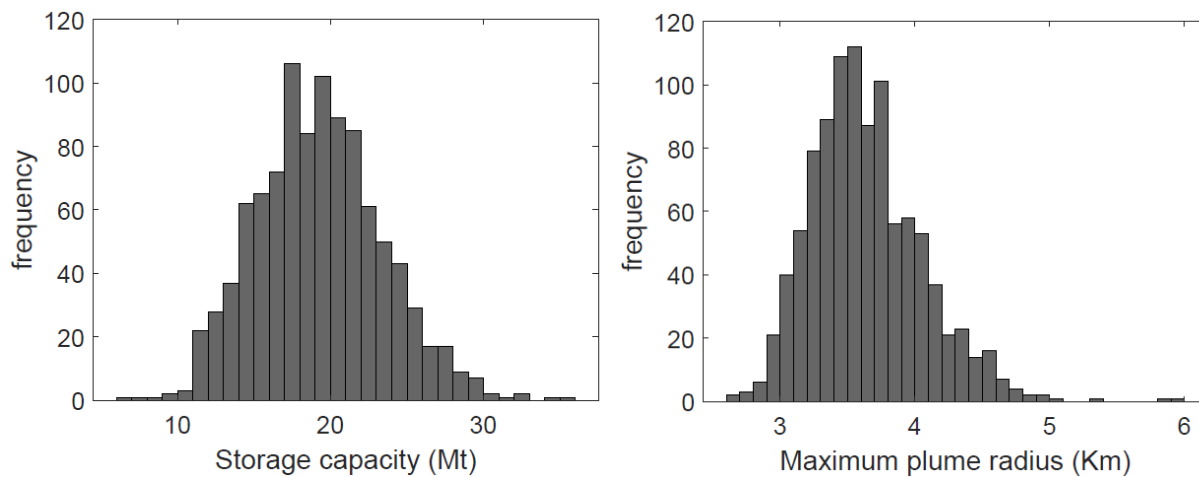


Figure 11: Storage capacity and maximum radius of the CO₂ plume after 25 years of injection for the Arbuckle aquifer at the Patterson site.

References

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