OGS Fact Sheet No. 1
Geological Carbon Management in Oklahoma

The Oklahoma Geological Survey
November, 2021

1. Introduction

In response to an increasing frequency of requests to the Oklahoma Geological Survey (OGS), a group of OGS staff prepared this fact sheet on *geological carbon management* (GCM), an umbrella term for using the subsurface to mitigate carbon emissions. The focus is primarily on *geological carbon sequestration*, one type of *carbon sequestration*. Carbon sequestration encompasses a still wider range of approaches, such as managing ecosystems to enhance CO_2 sequestration in soils, plants, and the oceans[1]. We focus here on issues surrounding geological site selection and monitoring, leaving out many topics in the politics, economics, and social science of GCM, as well as questions surrounding the sources and transport of carbon dioxide (CO_2) and methane (CH_4)[2-5].

2. Carbon capture & storage: definitions & goals

Carbon capture, and storage (CCS) involves injecting CO_2 into geological formations. CCS is a form of *geostorage*, the latter a term that encompasses the subsurface storage of any fuel such as natural gas or hydrogen (H_2). CCS contributes to "net-zero" goals (an economy that contributes no CO_2 to the atmosphere) by mitigating and offsetting industrial CO_2 emissions from power plants, fertilizer production, gas processing, and cement manufacturing, amongst many others. CCS also offsets emissions from sectors where CO_2 emissions are geographically distributed and therefore more difficult to mitigate, such as aviation and agriculture. CCS also can sequester CO_2 collected by *direct air capture* (DAC).

Carbon capture utilization and storage (CCUS) is a subset of CCS where CO_2 is used for industrial purposes. A common use in Oklahoma is *enhanced oil recovery* (EOR), wherein CO_2 is used to stimulate oil and gas production, leaving an estimated 90-95% of used CO_2 trapped in the subsurface[6]. CCUS also describes the conversion of stored CO_2 into various fuels, industrial minerals, polymers, agricultural applications, and many others. A special case of considerable interest for Oklahoma is the pairing of CCS with of "blue" H_2 production from natural gas[7].

One unit of measure of atmospheric CO_2 is parts per million (ppm). CO_2 is currently at >400 ppm, up from ~350 ppm in 1990, and a longer-term <300 ppm during the rise of industrial civilization[8-10]. In contrast with ppm, most GCM uses units of metric tons, equivalent to ~1.1 US tons. The use of tonnage results from the measurable weight of carbon that makes up >80% of most hydrocarbon fuels[11]. Setting aside CH_4 emissions, the carbon bonds with oxygen, resulting in ~3.1 tons of atmospheric CO_2 for every ton of carbon. Current estimates of global CO_2 emissions are >30 billion tons (Gt) of CO_2 per year, with Oklahoma contributing >46 million tons (Mt) per year[12]. GCM will likely include a geographically distributed range of sizes and storage durations to contribute to net zero, and today there are already 27 CCS focus sites worldwide targeting 36 Mt of storage with dozens more in the pipeline[13].

3. Carbon capture & storage: principles

CO_2 is typically injected as a supercritical fluid brine where it might be *trapped* in one of the following ways (Fig. 1).

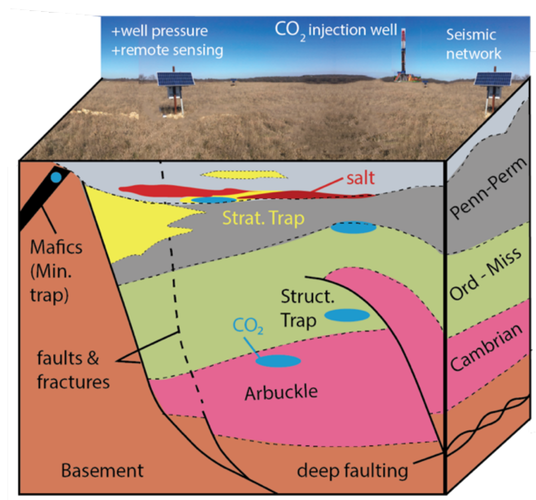

Figure 1. Schematic of carbon management targets in Oklahoma.

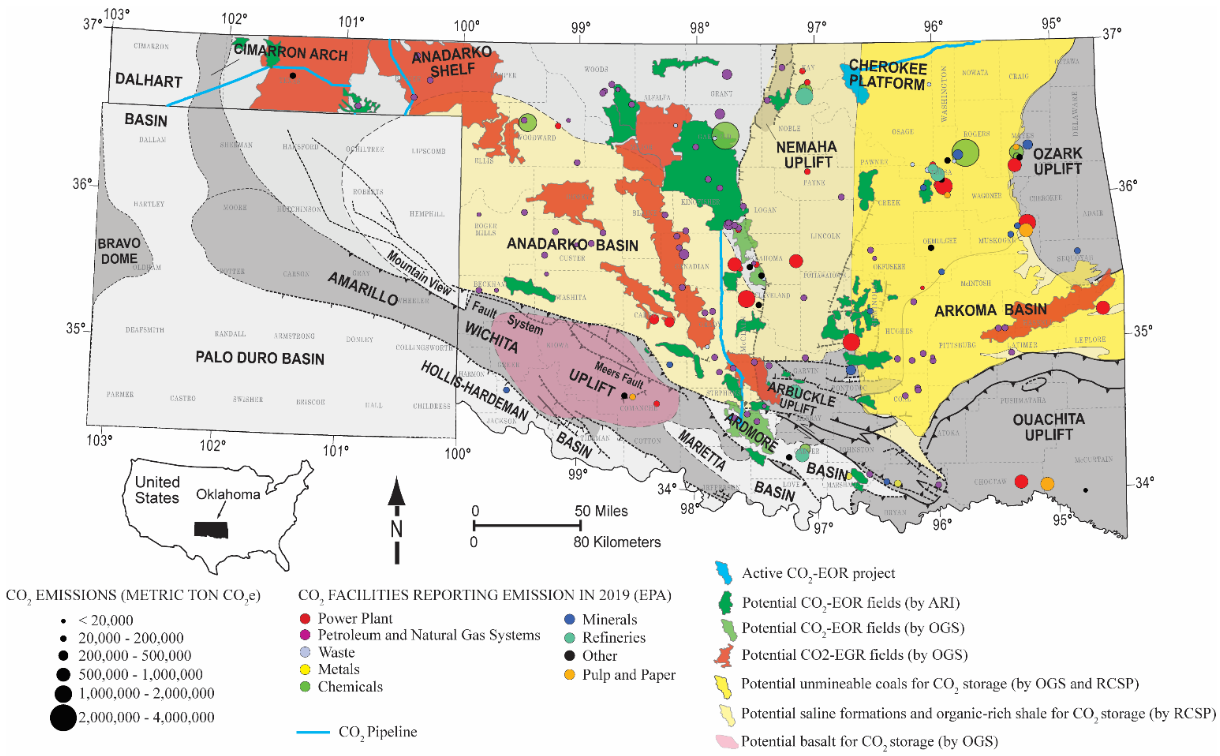

Figure 2. Geological provinces and prominent carbon emissions and facilities [12,22-27]. Major CO_2 emissions are illustrated for the year 2019 along with known CO_2 pipelines, geological provinces, and some major oil and gas fields.

CO_2 brine might be structurally or stratigraphically trapped against an overlying impermeable layer, residually in the natural pore space, or dissolved into surrounding natural pore water (solubility trapping)[14]. Mineral trapping can also occur when CO_2 reacts to form a carbon-rich solid[15-17]. Such mineralization is enhanced in magnesium-iron rich, "mafic" rocks, and has an advantage that the CO_2 cannot easily escape once solidified.

As a brine, CO_2 is similar to many injected fluids, such as liquid petroleum gas, residual oil, and even water with low total dissolved solids. These fluids are less dense than the background "connate" fluids. In contrast, other injected fluids such as produced-water or bio-oil are denser than the connate fluids. The buoyancy of injected CO_2 means that a reservoir must have sufficient storage capacity, injectivity *and* a reservoir seal that will hold the lower density fluid that can migrate upward along higher permeability pathways including faults, fractures, or compromised well completions. At depths greater than 2625 ft (800 m) the density of the CO_2 is high enough to allow efficient pore filling and to decrease the buoyancy difference compared with connate fluids[14]. In most cases CCS targets *saline aquifers*, the porous formations that reside below *underground sources of drinking water* (USDWs)[12]. Studies of unconventional oil and gas reservoirs also find that through pore-scale adsorption and absorption processes the geological targets for hydraulic-fracturing production of oil and gas may also be targets for CCS[18].

The simplest estimate of reservoir storage capacity multiplies the thickness and area of a potential reservoir by its porosity, along with an efficiency factor that ranges from 0.0 to 1.0, typically set at 0.1-0.2 to account for the fraction of the reservoir that is available for storage[19, 20]. Despite simplifying many obstacles to CO_2 invasion, such as pore-throat barriers, pore-closing mineralizing chemical reactions, and a wide range of flow instabilities, such simple estimates can be quite useful for initial mapping of storage potential over large areas.

4. Storage estimates for GCM in Oklahoma

Oklahoma was an early adopter of GCM[2], with CCUS efforts stemming back to 1982. Today, for example, CO_2 is being captured from emissions streams at fertilizer plants in Enid, OK, and Coffeyville, KS[21]. That CO_2 is piped to oil fields in Southern Oklahoma and Osage County where it is used, and largely captured, during EOR. The map of Oklahoma[12, 22-27] (Fig. 2) illustrates the complex geological landscape of Oklahoma including uplifts (such as the Arbuckle Uplift and Wichita Uplift) exposing Ordovician, Cambrian, and pre-Cambrian rocks at the surface versus deep sedimentary basins (such as the Anadarko Basin and Arkoma Basin) that have Permian rocks at the surface. The generalized cross-section (Fig. 3) shows that the sedimentary rocks in the Anadarko Basin can be more than 40,000 ft thick, while the sedimentary sequence is less than 10,000 ft thick to the north and northeast of Oklahoma City.

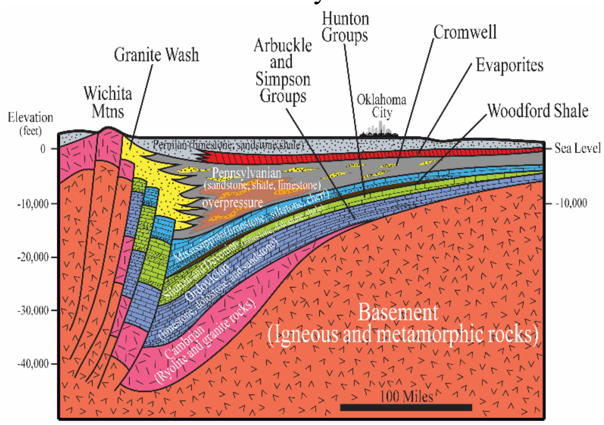

Figure 3. Generalized cross-section of the Anadarko Basin on the left or south-southwest to the Anadarko Shelf on the right or north-northwest[26]. Mafic zones are locally distributed in the basement and lower Cambrian sections.

Because of the *heterogeneity of Oklahoma's geology*, there is an abundance of viable target formations for variable carbon sequestration and use approaches. By way of example, the OGS has compiled preliminary effective porosity data for the Cromwell, Hunton, Simpson, Arbuckle Groups — note that *group* is a term for numerous geological formations of a certain age range and character — as well as some igneous mafic units one might target for mineral trapping (Table 1). These values were used to estimate the land area that would be required to store 10 Mt CO_2 assuming mean thickness and porosity, a relatively high efficiency factor of 0.50, and a density difference of 515 kilograms per cubic meter[28].

The "CO_2 areas" shown in Table 1 indicate that the Arbuckle Group and Mafic units can store 10 Mt CO_2 with the smallest footprints owing mostly to their great thickness. The Cromwell, Hunton, and Simpson Groups also have tremendous storage capacities throughout Oklahoma considering that there are tens of thousands of acres available in each of several counties. For example, there are more than 65,000 acres in Haskell County where these formations reside in the subsurface at suitable conditions. There may be countless other viable CCUS targets in Oklahoma and capacity for storing a combined total of many hundreds of Mt, if not Gt, of CO_2.

Table 1 Estimates of land area needed for subsurface storage of 10 Mt CO_2 in promising target zones in Oklahoma. Note porosity values use a variety of methods, and are here presented only as qualitative estimates.

	Zone (# sites studied)	*variable (units)*	mean thickness, h (ft)	mean porosity, ϕ (%)	CO_2 area, A (acres)
Geological Zone	**Cromwell** (7)		58	9.9	5491
	Hunton Group (1)		160	16.0	1230
	Simpson Group (7)		147	10.7	2002
	Arbuckle (2)		432	7.1	1026
	Mafic or Precambrian (2)		1080	3.0	972
	mean value from OGS geological studies				
	calculated footprint required for storage of 10 Mt CO_2				

5. Mitigating Hazards of Leakage & Seismicity

As with all geostorage efforts, CCS has risks, with widely discussed hazards of leakage to the surface along vertical pathways such as fractures, faults, or the wellbores themselves, as well as leakage laterally into surrounding geological formations[29]. Additionally, any form of geostorage risks causing a possible increased frequency of earthquakes, a.k.a. induced seismicity[30].

Leakage is widely discussed in terms of some acceptable rate, such as 0.01% of stored CO_2 per year[20], though it is expected to vary over time as a function of wellbore integrity, injection rate, and trapping mechanisms. Leakage is primarily mitigated through site characterization focusing on caprock integrity and seal quality. Borehole engineering also can mediate leakage through the use, for example, of polymers that stabilize cements that otherwise dissolve with introduction of carbonic acids[31]. Once captured, regional and site-specific well-pressure monitoring can detect leakage, as has been shown by both computational modelling and active field experiments[32,33].

The other widely considered hazard is an increase in earthquake activity as has occurred from produced-water injection over the last decade[30]. For example, 18 earthquakes of magnitude (M) 3 or greater occurred between 2006 and 2011 at the Texas Cogdell oil field following the injection of CO_2 and other gases[34,35]. This example, along with a myriad of case studies over the last decade, illustrates that seismic risk will depend on hydromechanical properties of the injection reservoir, state of stress, injection rates and pressures, and net total volumes of injected fluid.

Underground injection (UIC) of produced wastewater in Oklahoma illustrates that good site selection and careful project design can also lower seismic risk to acceptably low levels[30]. In these instances, seismicity can occur from pumping at moderate rates over years, or very high rates over a matter of hours as is the case with hydraulic fracturing. Based on such mitigation efforts, as well as the mapping of faults in the subsurface via geological and geophysical investigation, a common explanation for the earthquake activity is that the input of water causes pressure changes that push the fault to failure[36]. Pairing that scientific observation and deduction with regulatory action can then stem the effects of induced seismicity and borehole leakage.

Currently, the Oklahoma Corporation Commission (OCC) works to mitigate seismicity during wastewater disposal and hydraulic fracturing. OCC implemented injection reductions in 2016 across a broad swath of the state that have, in part, led to a reduction in the number of earthquakes of magnitude 3 or greater. For example, over 900 earthquakes M3 or greater occurred in 2015, but this number fell to 45 by 2020. In addition, after larger events (M4.0 or greater), OCC often implemented rapid mitigation measures including shutting-in wells closest to the earthquake epicenter, the earthquake's surface point of origin, with gradual reductions stepping away from the epicenter. OGS has provided the OCC with direct scientific observations of the subsurface geology and associated seismic behavior of activated faults via the OGS-maintained state-wide seismometer network[37]. Through this OGS-supported research, the regulatory actions reduced the probability of aftershocks in the affected areas[34]. Such efforts provide a glimpse of existing risk-based approaches that could be evaluated for possible future implementation during future GCM in Oklahoma.

6. Plain Language Summary Statement

Oklahoma's diverse and heterogeneous geology offers numerous opportunities for geological carbon management, from carbon-dioxide injection accompanying oil and gas production, to storage of emissions resulting from hydrogen production, to long-term and large volume sequestration of carbon dioxide Experience to date suggests that geological and geophysical investigations can help mitigate many of the leakage and earthquake hazards that can accompany such subsurface, geological carbon management.

7. Acknowledgements

OGS thanks Holly Buck (State University of New York at Buffalo), Tim Filley (University of Oklahoma), Franek Hasiuk (Kansas Geological Survey), Seyyed Hosseini (Bureau of Economic Geology, UT Austin), and Camelia Knapp (Oklahoma State University) for technical reviews. This effort was self-funded by the OGS, a state agency based at the University of Oklahoma.

Cite as: Oklahoma Geological Survey, 2021, Geological Carbon Management in Oklahoma, OGS Fact Sheet No.1, doi:10.xxxx.yyyy

Web Site for .pdf download of OGS fact sheets: https://www.ou.edu/ogs/publications/factsheets

Contact: ogs@ou.edu

8. References

1. Farrelly, D.J., et al., 2013. Carbon sequestration and the role of biological carbon mitigation: a review. *Renewable and sustainable energy rev.*, *21*, pp.712-727.
2. Abramson, E., et al., 2020, Great Plains Institute whitepaper on regional infrastructure for midcentury decarbonization; Note numerous other resources on the Great Plains Institute website: https://www.betterenergy.org.
3. de Coninck, H. and Benson, S.M., 2014. Carbon dioxide capture and storage: issues and prospects. *Ann. Rev. of environment and resources*, *39*, 243-270.
4. The CDR Primer: https://cdrprimer.org
5. Walter, J.I., et al., 2020, Convergence Accelerator Workshop on Atmospheric Carbon Reduction: https://ou.edu/ogs/workshops/nsf-convergence-accelerator-workshop---carbon-reduction
6. Melzer, L.S., 2012. Carbon dioxide enhanced oil recovery (CO2 EOR): Factors involved in adding carbon capture, utilization and storage (CCUS) to

enhanced oil recovery. *Center for Climate and Energy Solutions*, pp.1-17.
7. Oklahoma Hydrogen Task Force: https://ee.ok.gov/resource/hydrogen-task-force/
8. NOAA: https://www.esrl.noaa.gov/gmd/obop/mlo/
9. IEA: https://www.iea.org/reports/global-energy-review-2021/co2-emissions
10. Keeling, R.F. and Graven, H.D., 2021. Insights from Time Series of Atmospheric Carbon Dioxide and Related Tracers. *Ann. Rev. of Environment and Resources*, *46*, 85-110.
11. Jarvie, D.M., 1991. AAPG Special Volume on total organic carbon (TOC) analysis: Chapter 11: Geochemical methods and exploration.
12. See https://www.epa.gov for numerous tools for tracking emissions and conducting conversions
13. See the CCS Institute for numerous fact sheets & additional resources: https://www.globalccsinstitute.com/resources/global-status-report/
14. Friedmann, S.J., 2007. Geological carbon dioxide sequestration. Elements, 3(3): 179-184.
15. Matter, J.M. and Kelemen, P.B., 2009. Permanent storage of carbon dioxide in geological reservoirs by mineral carbonation. *Nature Geoscience*, *2*(12), pp.837-841.
16. McGrail, B.P., et al., 2006. Potential for carbon dioxide sequestration in flood basalts. *Journal of Geophysical Research: Solid Earth*, *111*(B12).
17. Hills CD, et al., 2020, Mineralization Technology for Carbon Capture, Utilization, and Storage, *Frontiers of Energy Research,* v. 8, doi: 10.3389/fenrg.2020.00142
18. Fakher, S. and Imqam, A., 2020. A review of carbon dioxide adsorption to unconventional shale rocks methodology, measurement, and calculation. *SN Applied Sciences*, *2*(1), pp.1-14.
19. Aminu, M.D., et al., 2017. A review of developments in carbon dioxide storage. Applied Energy, 208: 1389-1419.
20. See https://netl.doe.gov/coal/carbon-storage/strategic-program-support/best-practices-manuals for the Department of Energy, National Energy Technology Laboratory Best Practices documents
21. Liu, Hanming et al., 2018, Overview of CCS Facilities Globally, 14th Greenhouse Gas Control Technologies Conference, Melbourne.
22. Dutton, S. P., 1984, Fan-delta Granite wash of the Texas panhandle: Oklahoma City Geological Society, 1–144.
23. Campbell, J. A., et al., 1988, Habitat of petroleum in Permian rocks of the midcontinent region, in W. A. Morgan and J. A. Babcock, eds., SEPM Special Publication 1, 13–35.
24. McConnell, D. A., et al., 1990, Morphology of the frontal fault zone, southwest Oklahoma: Implications for deformation and deposition in the Wichita uplift and Anadarko Basin: Geology, 18, 634–637.
25. Northcutt, R. A., and J. A. Campbell, 1995, Geologic provinces of Oklahoma: Oklahoma Geological Survey OpenFile Report 5-95.
26. Johnson, K. S., and K. V. Luza, 2008, Earth sciences and mineral resources of Oklahoma: Oklahoma Geological Survey, Educational Publication 9, 22.
27. LoCricchio, E., 2012, Granite wash play overview, Anadarko basin: Stratigraphic framework and controls on Pennsylvanian Granite wash production, Anadarko Basin, Texas and Oklahoma: AAPG Annual Convention and Exhibition, 1–17.
28. Kimbrel, E.H., et al., 2015. Experimental characterization of nonwetting phase trapping and implications for geologic CO2 sequestration. *International Journal of Greenhouse Gas Control*, *42*, pp.1-15.
29. McGrail, B.P., et al., 2006. Potential for carbon dioxide sequestration in flood basalts. *Journal of Geophysical Research: Solid Earth*, *111*(B12).
30. White, J.A. and Foxall, W., 2016. Assessing induced seismicity risk at CO_2 storage projects: Recent progress and remaining challenges. Intern. Journ. of Greenhouse Gas Control, 49: 413-424.
31. Tavassoli, S., et al., 2018. An experimental and numerical study of wellbore leakage mitigation using pH-triggered polymer gelant. *Fuel*, *217*.
32. Hovorka, S.D., et al., 2011. Monitoring a large volume CO2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA. *Energy Procedia*, *4*, 3478-3485.
33. Sun, A.Y. and Nicot, J.P., 2012. Inversion of pressure anomaly data for detecting leakage at geologic carbon sequestration sites. *Advances in Water Res.*, *44*, 20-29.
34. Walter, J.I., et al., 2018. Natural and induced seismicity in the Texas and Oklahoma Panhandles. *Seismological Res. Letters*, *89*, 2437-2446.
35. Gan, W. and Frohlich, C., 2013. Gas injection may have triggered earthquakes in the Cogdell oil field, Texas. Proc. Nat. Ac. Sci., 110, 18786-18791.
36. Goebel, T., et al., 2019, Aftershock deficiency of induced earthquake sequences during rapid mitigation efforts in Oklahoma, Earth Planet. Sci. Let., 522, 135-143
37. Walter, J. I., P. et al., 2020, The Oklahoma Geological Survey Statewide Seismic Network, *Seismological Research Letters, 91*(2A): 611–621, https://doi.org/10.1785/0220190211.