CADMUS

Carbon Capture, Utilization, and Sequestration:

A State Comparison of Technical and Policy Issues

United States Energy Association

Prepared by:
Shari Ring
Ryan Keeling
Kyrien Edwards
Marie Lewis
The Cadmus Group, LLC

October 2021

Carbon Capture, Utilization, and Sequestration: A State Comparison of Technical and Policy Issues

PROMOTING DOMESTIC AND INTERNATIONAL CONSENSUS ON FOSSIL ENERGY TECHNOLOGIES: CARBON CAPTURE, UTILIZATION, AND STORAGE AND CARBON MANAGEMENT

Prepared for:

United States Department of Energy – Office of Fossil Energy and Carbon Management and United States Energy Association

Sub-Agreement: USEA/DOE-0031812-633-08

Authors:

Shari Ring, The Cadmus Group LLC
Ryan Keeling, The Cadmus Group LLC
Kyrien Edwards, The Cadmus Group LLC
Marie Lewis, The Cadmus Group LLC

United States Energy Association
1300 Pennsylvania Avenue, NW
Suite 550, Mailbox 142
Washington, DC 20004
+1 202 312-1230 (USA)

This report is made possible by the support of the American people through the United States Department of Energy – Office of Fossil Energy and Carbon Management. The contents are the responsibility of the United States Energy Association and do not necessarily reflect the views of USDOE or the United States Government.

Contents

Carbon Capture, Utilization, and Sequestration: A State Comparison of Technical and Policy Issues

Introduction

Carbon Capture, Utilization, and Sequestration (CCUS) encompasses a suite of technologies that involve capturing carbon dioxide (CO_2) from emission sources or directly from the atmosphere, and compressing, transporting, and injecting it into deep subsurface formations for storage.[1] CCUS has a critical role to play in decarbonizing the global economy and achieving climate change goals. It also offers economic benefits to operators (e.g., via the federal 45Q tax credit[2] that provides incentives for sequestering CO_2 along with various state tax or financial incentives) and generates jobs that can benefit local communities.

Large-scale deployment of CCUS technology will benefit from a strong regulatory regime that is informed by science and experience.[3] Decades of research and development, along with experience from CCUS field projects has generated a body of knowledge suggesting that CCUS can be conducted safely, resulting in minimal environmental impact if storage sites are properly selected, characterized, operated, monitored, and closed.[4] Significant research into CCUS technologies, much of it led by DOE and its Regional Carbon Sequestration Partnerships, has demonstrated the viability of sequestration technologies in various geologic scenarios. Suitable geologic formations[5] exist throughout the US, and opportunities exist nationwide to participate in commercial-scale CCUS.

The maturity of CCUS technologies, increased focus on climate change objectives to reduce CO_2 emissions, and economic incentives will likely result in an increase in the number of CCUS projects over the next several years. Prospective operators need to understand the nuances of permitting for the breadth of activities involved in siting and initiating a CCUS project. Selecting and securing a CCUS site involves numerous technical and policy considerations, involving a variety of state and (in some cases) federal agencies such as:

- Suitable Geologic Reservoirs. A storage formation must have sufficient capacity to receive large volumes of CO_2 and be overlain by a competent confining formation. State-specific research into developing formation capacity has increased the knowledge base on these formations. Where possible, storage reservoirs should be located near large anthropogenic CO_2 emission sources, such as those associated with agriculture, high CO_2 producing industries, or oil and gas processing facilities. This "source-sink" matching is critical, as limiting transportation distances can reduce transportation risks and increase the profitability of a CCUS project. Optimally, the

---

[1] CCUS may also involve transforming CO_2 for utilization in industrial processes or as feedstock for useful commercial products; however, for the purpose of this review, CCUS refers to injection of CO_2 into the subsurface.
[2] In Section 45Q of the Internal Revenue Code (26 U.S. Code § 45Q. Credit for Carbon Oxide Sequestration), the 45Q tax credit can be claimed by a carbon capture project when the CO_2 is securely stored through either storage in geologic formations or utilization.
[3] White House Council on Environmental Quality. Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Released June 30, 2021.
[4] T. Warner, D. Vikara, A. Guinan, R. Dilmore, R. Walter, T. Stribley, and M. McMillen. "Overview of Failure Modes and Effects Associated with CO_2 Injection and Storage Operations in Saline Formations," National Energy Technology Laboratory, Pittsburgh, PA, United States, October 16, 2020.
[5] These formation types include depleting oil fields, saline formations, coal seams, basalts, and organic shales.

storage formation will be located close to the source or near existing CO_2 pipelines or roads capable of carrying truck traffic.

- CO_2 Transport. The current lack of CO_2 pipeline infrastructure in many states means that significant CO_2 pipeline construction would need to occur to make CCUS commercially attractive for stakeholders. Research is underway to identify priorities for pipeline development in the US. For example, the Great Plains Institute used the Los Alamos National Laboratory's SimCCS model to identify an optimal regional-scale CO_2 transportation network that would be capable of meeting decarbonization goals by 2050. It envisions buildout of a network of large trunk pipelines and smaller feeder lines to connect areas with large-scale ethanol production to areas where enhanced oil recovery (EOR) is occurring.[6] The states are in varying stages of developing and regulating these pipelines.
- CO_2 Storage Statutory Landscape. Many states are developing "Carbon Dioxide Storage Acts," which may set a regulatory framework, offer incentives, and provide policy clarity for how CCUS operations are addressed, either via new regulations or within existing regulatory schemes (e.g., for pore space ownership or eminent domain). These policies can provide the regulatory certainty that investors and operators need to facilitate commercial-scale investment in CCUS.
- Regulations for Injecting CO_2. Different requirements apply, depending on whether injection of CO_2 is for long term geologic storage (i.e., Class VI injection wells) or as part of an oil and gas recovery operation (i.e., Class II). Operators seeking to convert Class II wells for geologic sequestration would need to be aware of any differing requirements such that, once converted, the well meets the Class VI well construction requirements. Few states have primary enforcement authority (primacy) for Class VI; therefore, permits for CO_2 injection for GS would be issued by US EPA pursuant to the federal Class VI Rule at 40 CFR 146.81 *et seq*.
- Oil and Gas Field Requirements. Where EOR is already in play—particularly in depleting oil and gas-bearing formations—transitioning to using the fields for CO_2 storage may be economically advantageous. For example, if surface facilities that support injection operations are in place, they could be adapted to accommodate CO_2 and allow the operator to meet the Class VI CO_2 injection requirements. Operators planning for CCUS in existing oil and gas fields would need to consider existing siting, spacing, and unitization requirements for a field. As with conversion of Class II injection wells for CCUS, prospective operators must be mindful whether existing production wells have been constructed to meet the requirements for CO_2 injection.
- Environmental Laws and Regulations. Other environmental considerations include how a state defines underground sources of drinking water (USDWs) or fresh water for injection and production well construction purposes; this may be significant to operators planning to convert production wells for CO_2 injection, where the well's construction must consider protection of all ground water with a total dissolved solids (TDS) content of 10,000 mg/L or less.[7] Additionally, where injection-induced seismicity is a concern, states may have requirements or guidelines to follow. Also, air quality regulations (especially related to CO_2 or methane releases) or industrial siting requirements would need to be considered by prospective operators. Water rights and the prioritization of ground water and surface water uses are also essential for site selection and use of this natural resource.
- Eminent Domain. Many states consider CCUS-related activities (particularly related to oil and gas fields development) to be a public use for the common good, and allow the taking of private property if proper procedures are followed and fair compensation is made. Generally, eminent domain is used for transportation (pipeline), underground storage, and surface operations. Some

[6] Decarb America Research Initiative. Carbon Dioxide Pipelines. Available at https://decarbamerica.org/interactive-maps/carbon-dioxide-pipelines/.

[7] This TDS level is consistent with the definition of an USDW at 40 CFR 144.3.

states have begun to expand their eminent domain authorities to CO_2 storage operations, which largely emulate those of oil and gas development.

- Mineral Rights, Surface Rights, and Pore Space Ownership. States vary regarding whether subsurface (mineral) or surface rights dominate when multiple uses are planned. CO_2 may or may not be explicitly included in the state's definition of a "mineral," causing ambiguity. Many states define a "mineral" as oil, natural gas, or any naturally occurring substance in subsurface strata. Pore space is generally implied in state statute, typically belonging to the surface owner and consisting of all subsurface space that is devoid of minerals. In states where it is not explicitly defined, it is unclear whether CCUS operators must own the surface rights, mineral rights, pore space, or a combination of such in order to lawfully sequester CO_2. Due to the lack of explicit statute, the majority of the state's legal language regarding CCUS in the context of subsurface rights is largely interpretive and based on historic legal proceedings. Additionally, many states have dormant mineral rights clauses, meaning that, if the title to such minerals is not used for a given time period, the mineral rights will revert to the surface owner.
- Lithium Ownership and Extraction. Lithium production from subsurface brine water, commonly associated with oil and gas production, is seeing a renewed interest from operators due to demand and readily accessible oilfield brine fluids. Although not immediately relevant to CCUS, research regarding lithium production and regulation was undertaken given the recent increase in lithium demand in the transportation sector. Two states that were researched for this report (California and Utah) have lithium deposits. In California, a potential global leader in lithium production, a pending Blue-Ribbon Commission report is under development to evaluate economic and environmental impacts, tax credits, marketing opportunities, and proposed regulations for lithium extraction and production. While research on the feasibility of extracting lithium from oil and gas wastewater brines in Utah is underway, our research only identified regulations related to extraction of lithium via evaporation ponds.

Prospective CCUS project operators selecting sites will need to consider the existing applicable policy landscape, including requirements and incentives for CO_2 transport and storage in individual states. In addition to federal requirements, individual states have unique and specific statutes, regulations, and policies (many of which are ingrained in long-standing legal frameworks). Additionally, this research may be of use to policy makers who are considering the development of new regulations or adapting existing regulatory regimes to accommodate CCUS technology in their states or local jurisdictions.

This report evaluates how ten states (Alabama, California, Indiana, Kansas, Louisiana, Michigan, Mississippi, Nebraska, Oklahoma, and Utah) address these policy issues. This report is a follow-on to "Study on States' Policies and Regulations per CO_2-EOR Storage Conventional, ROZ and EOR in Shale,"[8] which evaluated states in the Midwest and Appalachia; that report also provided an overview of the federal regulatory landscape.

The tables on the following pages summarize the physical and policy landscape as it relates to CCUS. It should be noted that these tables present high level summaries, and the details of our research are in the state-specific summaries that follow the tables.

[8] K. Koski, J. J. Richardson, Jr., T.K. Righetti, and S. Taylor. Study on States' Policies and Regulations per CO2-EOR Storage Conventional, ROZ and EOR in Shale: Permitting, Infrastructure, Incentives, Royalty Owners, Eminent Domain, Mineral-Pore Space, and Storage Lease Issues. Prepared for: US DOE, Office of Fossil Energy and United States Energy Association. September 2020.

CO_2 Geologic Storage Potential and Pipelines

The availability of space to store large volumes of CO_2 in subsurface rock layers, or strata, known as storage capacity, is one of several key elements that determines the success of a commercial-scale CCUS project. CO_2 storage reservoirs, referred to as sinks, are typically deep saline formations with enough storage, or pore space, to contain the volumes of CO_2 proposed to be stored. Geologic storage of CO_2 can also occur in depleting EOR fields and unmineable coal seams. CCUS activities in the states studied range from feasibility studies of the entire life cycle of CCUS projects, to demonstration of CO_2 injection for EOR and storage (e.g., in Kansas, Michigan, Mississippi, and Oklahoma), to pending Class VI permit applications in California, Indiana, and in Louisiana, where a prospective operator seeks to capitalize on a favorable supply chain along the state's "industrial corridor," where multiple CO_2 sources are located in close proximity to the proposed geologic sink.

Often, the geologic sink does not directly overlie the source of CO_2, necessitating the use of pipelines as a means of transportation. While some states have extensive natural gas transmission pipelines,[9] they have varying levels of CO_2 pipeline infrastructure connecting CO_2 sources to sinks—ranging from non-existent or limited infrastructure, to states with extensive CO_2-EOR infrastructure and transmission pipelines. The current lack of CO_2 pipeline infrastructure in many states means that significant CO_2 pipeline construction would need to occur if CCUS became commercially attractive. Research to expand pipeline capacity is underway. A 1,200 mile conceptual pipeline proposal would connect CO_2 sources across Nebraska, Iowa, Minnesota, South Dakota, and Illinois, and transport it to viable sinks across those five states, and CCUS research initiatives in Utah are focused on areas with existing pipeline networks.

CCUS Activities in the States			
	Major CO_2 Sources and Sinks	**CCUS Research**	**CO_2 Pipelines**
AL	**Sources:** Coal power plants **Sinks:** oil and gas reservoirs, saline formations, and coal seams of the Black Warrior Basin	Research is focused on coal beds of the Black Warrior Basin and a pilot project in the Citronelle Oil Field.	None.
CA	**Sources:** Bioenergy, industrial, electricity generation, cement, and refineries **Sinks**: Saline formations	A Class VI permit application for storage in a deep saline formation is pending.	None currently; however, pipeline locations have been proposed based on known CO_2 sources and potential geologic storage locations.
IN	**Sources:** Coal and gas power plants, steel, ethanol, refineries, metals and minerals, and cement **Sinks:** Saline formations in the Illinois Basin, particularly the Mt. Simon Sandstone	Proposed or completed CCUS projects include: a small-scale CO_2 injection test in Barrett, and a planned Wabash Valley Resources project in Harrison.	None–attempts to establish CO_2 pipelines have stalled due to issues securing eminent domain and public opposition.
KS	**Sources:** Coal power plants, hydrogen, ammonia, and ethanol, refineries **Sinks:** Saline formations, including the Osage, Viola, and Arbuckle Groups	The state is working with industry partners to study CO_2 EOR at Wellington Field and the Hall-Gurney Field.	Two small-scale CO_2 pipelines connect industrial point sources to CO_2-EOR projects in Oklahoma. Several interstate CO_2 transport pipelines are under evaluation.

[9] There is no published research regarding the repurposing of natural gas pipelines for CO_2 transportation. While they are both gases, they will behave differently at supercritical conditions, forcing the pipeline to meet various operation criteria such as pressure, temperature, and diameter.

CCUS Activities in the States			
	Major CO_2 Sources and Sinks	**CCUS Research**	**CO_2 Pipelines**
LA	**Sources:** Refineries, gas and coal power plants, ammonia, and pulp and paper plants **Sinks:** Saline formations, depleted oil and gas reservoirs in the south, and salt domes in the north	Planned CCUS projects include a proposed gasification facility by Lake Charles Methanol and the Gulf Coast Sequestration project.	The co-location of refineries and CO_2 sinks in the state's "Industrial Corridor" may limit the need for an extensive CO_2 pipeline buildout.
MI	**Sources:** Coal and gas power plants, steel, metals and minerals, and cement **Sinks:** Saline formations, including the Mt. Simon Sandstone and the Niagaran Pinnacle Reef Trend	Core Energy CO_2-EOR program in Otsego County, and a small-scale CO_2 injection test within the Northern Pinnacle Reef Trend.	An 11-mile transmission pipeline carries CO_2 produced at the Antrim Shale gas fields to the Core Energy project.
MS	**Sources:** Gas power plants, chemical plants, petroleum refineries, and gas processing facilities **Sinks:** Saline formations	CO_2 storage capacity demonstration project at the Cranfield Site in southwestern Mississippi.	CO_2 pipelines extend from midwestern Mississippi towards Alabama, Mississippi, and Louisiana.
NE	**Sources:** Coal power plants, cement kilns, and ethanol and ammonia facilities **Sinks:** Saline formations, including the Cloverly Formation and the Cedar Hills Formation	Feasibility study of CCUS potential at the Gerald Gentleman Station.	None, but plans for a 1,200-mile pipeline were announced in March 2021.
OK	**Sources:** Coal and gas power plants, gas processing, refineries, ammonia, hydrogen, and chemical manufacturing **Sinks:** Saline formations and the oil and gas reservoirs of the Anadarko Basin	Research is focused on injecting anthropogenic CO_2 into depleted oil wells for EOR; e.g., the Enid Fertilizer facility supplies CO_2 for EOR in the Anadarko Basin.	There are intrastate pipelines for CO_2-EOR projects and interstate pipelines crossing into Texas and Kansas. A "Conceptual CO_2 Pipeline System" aims to connect established point sources to sinks.
UT	**Sources:** Natural CO_2, coal power plants, and cement **Sinks:** Saline formations and oil fields in the northern, western, and southwestern parts of the state	Research is focused on injecting naturally-sourced CO_2 and CO_2 from various stationary sources located near existing pipelines in the Rocky Mountain Region.	Interstate transmission pipelines in southern Utah connect to the extensive CO_2 pipeline network in Texas, and a short stretch of pipeline in northeastern Utah connects a source in Wyoming with a sink in Colorado.

CO_2 as Commodity/Pollutant

States are beginning to address CO_2 as a taxable commodity that is tied to a use that they consider to be beneficial to their citizens and recognize the economic benefits of CCUS. Most of the states researched apply a severance or other tax to use of CO_2 in oil field operations; however, a few states (California, Kansas, Michigan, Mississippi, and Utah) reduce that tax or offer other tax credits if the CO_2 is to be sequestered.

Some states such as California, Kansas, and Louisiana have recognized CO_2 as a contaminant (or include/do not exclude CO_2 in their broad definitions of an "air pollutant"), while other states, such as Michigan and Utah have set goals for reducing CO_2 emissions to the atmosphere. In California, CO_2 is subject to "cap and trade" provisions. Several states have developed CO_2 Storage Acts that recognize CO_2 as a commodity; see the table on "CO_2 Storage Acts," below.

Treatment of CO_2 in the States		
	Treatment as a Commodity	**Treatment as a Pollutant**
AL	Several types of taxes apply to activities that generate CO_2, including: a severance tax on materials severed from the ground and sold, an annual privilege tax on the production or severance of oil and gas, and a mineral documentary tax on oil and gas leases.	CO_2 is not specifically addressed in the state's air pollution control rules.
CA	Sequestered CO_2 is excluded from compliance obligations for greenhouse gas emission limits. The state's Low Carbon Fuel Standard incorporates credits for CCS that can be traded on the credit market.	California directly recognizes CO_2 as a harmful pollutant, and emissions reductions are mandated under the Global Warming Solutions Act; a 2018 Executive Order sets a goal of achieving carbon neutrality by 2025.
IN	Storage of CO_2 is considered a public use and a benefit to the people of Indiana. Taxation applies to secondary recovery methods, but not enhanced recovery, which could include CO_2 flooding. The state offers financial incentives for coal plants employing CCUS.	CO_2 is not specifically referenced as a pollutant but may be included in the state's broad definition of an air contaminant.
KS	CO_2 is not directly addressed in the state's mineral severance tax codes, but may be subject to an excise tax on "gas" that is taken from the subsurface. The CO_2 Injection Well and Underground Storage Fund covers the costs of closure, long-term monitoring, and emergency or long-term remedial activities. A tax deduction exists for CCS equipment.	CO_2 is likely covered in the broad definition of an air pollutant.
LA	The Mineral and Energy Board has authority to receive a share of revenues from storage of CO_2 for secondary or tertiary recovery operations. The state's GS of CO_2 Act asserts that CO_2 is "a valuable commodity to the citizens of the state."	The state's GS of CO_2 Act directly addresses CO_2 as a greenhouse gas.
MI	The "Severance Tax Act" grants a reduced severance tax rate to approved EOR projects using CO_2 injection.	Several state policies/Executive Orders aim to reduce carbon pollution, promote clean energy deployment, reduce greenhouse gas emissions, and achieve economic decarbonization.
MS	Mississippi considers CO_2 a commodity for its use in EOR and CCUS, and allows a reduced sales tax rate for CO_2 sold for these uses.	Mississippi does not appear to recognize CO_2 as a pollutant.
NE	The Nebraska Geologic Storage of Carbon Dioxide Act specifically declares that stored CO_2 is a commodity.	Nebraska does not appear to enforce any CO_2-specific regulations.

Treatment of CO_2 in the States		
	Treatment as a Commodity	**Treatment as a Pollutant**
OK	Oklahoma's Carbon Capture and Geologic Sequestration Act declares CO_2 to be a valuable commodity.	Oklahoma does not appear to enforce any CO_2 -specific regulations.
UT	Oil and gas are both subject to a severance tax, with EOR receiving a 50 percent tax reduction.	While Utah does not currently list CO_2 as a pollutant, the state has taken measures to reduce CO_2 emissions.

Pipeline Regulations

Pipeline design, construction, operation, and maintenance are regulated at the state level, and typically possesses the minimum federal safety standards. Louisiana, Michigan, Mississippi, Oklahoma, and Utah are the only states presented in this research in which CO_2 pipeline or CO_2 transport are addressed in regulations. Louisiana and Oklahoma regulate CO_2 pipelines, and Mississippi requires that transportation of CO_2 comply with US DOT requirements. Mississippi gives each county's board of supervisors authority to regulate the construction and maintenance of CO_2 pipelines. In Utah, CO_2 captured and transported for sequestration is exempted from classification as a hazardous waste if the CO_2 generator and the well operator certify that the CO_2 stream has not been mixed with hazardous wastes and is transported in compliance with US DOT requirements. Alabama, California, Indiana, Kansas, and Nebraska do not have requirements specific to CO_2 pipelines.

Pipeline Regulations in the States	
AL	No requirements specific to CO_2 pipelines.
CA	No requirements specific to CO_2 pipelines.
IN	No requirements specific to CO_2 pipelines; however, "flow lines" within the boundaries of a lease or production unit are regulated.
KS	No requirements specific to CO_2 pipelines.
LA	CO_2 pipelines are regulated, with stipulations for transmission, transportation, accident reporting, design, construction, hydrostatic testing, operation, and maintenance.
MI	The transportation of a CO_2 stream must comply with US DOT requirements.
MS	There are no state-wide No requirements specific to CO_2 pipelines; however, each county's board of supervisors has authority to regulate the construction and maintenance of CO_2 pipelines.
NE	No requirements specific to CO_2 pipelines.
OK	The state corporation commissions has authority over intrastate and interstate CO_2 pipelines.
UT	CO_2 captured and transported for sequestration is exempted from classification as a hazardous waste if the CO_2 generator and the well operator certify that the CO_2 stream has not been mixed with hazardous wastes and is transported in compliance with US DOT requirements.

CO_2 Storage Acts

States are recognizing the value of CCUS as an economic opportunity or a burgeoning technology, and are beginning to pass laws to address CCUS and related activities. Several states (including Indiana, Kansas, Louisiana, Mississippi, Nebraska, Oklahoma, and Utah) have passed "Carbon Capture and Storage Acts," which generally assert these states' intent to address and provide regulatory certainty for CCUS project operators.

Many of these acts (in Kansas, Louisiana, Mississippi, Oklahoma, and Utah) authorize the development of rules for CO_2 injection for storage; Louisiana and Mississippi's Acts express the states' intent to apply to US EPA for Class VI UIC Program primacy.

Some of these Acts (e.g., in Louisiana and Mississippi) provide financial incentives in the form of CO_2 storage funds or assumption of post-closure liability that provides financial certainty over the long-term to prospective operators; Indiana's Act funds a CCUS research project. Indiana and Oklahoma statutorily describe how CCUS fits into existing regulatory frameworks such as eminent domain or unitization.

Alabama's Water Pollution Control Act contains draft rules for CO_2 storage facilities that address many of the same activities as those covered by the Federal Class VI Rule. Michigan and California have not passed a CO_2 Storage act, although two Michigan Executive Orders address reducing carbon pollution/economic decarbonization.

CO_2 Storage Acts in the States	
AL	The Alabama Water Pollution Control Act contains draft rules for CO_2 storage facilities which include requirements for Class VI injection wells that address the same activities as the Federal Class VI Rule.
CA	No acts specific to CO_2 storage or injection.
IN	Senate Bill 442 authorized a CCUS pilot project, provides the power of eminent domain for CO_2 storage facilities; it also provides financial incentives for coal plants employing CCUS.
KS	The Carbon Dioxide Reduction Act requires the development of CO_2 injection rules, although no rules have been finalized.
LA	The Geologic Sequestration of Carbon Dioxide Act promotes geologic storage of CO_2 and establishes a CO_2 Geologic Storage Trust Fund for inspections, testing and monitoring; remediation and repair of mechanical problems; or well plugging and abandonment. The state submitted a Class VI primacy application to US EPA.
MI	No specific CO_2 Storage act, although incentives are provided via cost recovery or reduced taxes if CO_2 is captured for storage. Two Executive Orders address reducing carbon pollution/economic decarbonization.
MS	The Mississippi Geologic Sequestration of Carbon Dioxide Act authorizes regulation of CO_2 storage (but no Class VI rules have been finalized), states an intent to apply for Class VI primacy, and authorizes a Carbon Dioxide Storage Fund to cover the cost of post-injection oversight of geologic storage facilities.
NE	The Geologic Storage of Carbon Dioxide Act gives regulatory authority over CO_2 storage facilities, establishes a Carbon Dioxide Storage Facility Trust Fund, and transfers titles for the storage facility and the CO_2, financial obligations, and long-term monitoring and site management responsibilities to the state.
OK	The Oklahoma Carbon Capture and Geologic Sequestration Act gives regulatory authority to either the OCC or the DEQ for CO_2 sequestration based on the type of storage formation; oversight of unitization for CO_2 sequestration facilities would be granted to the OCC.
UT	The "Rules for Carbon Capture and Geological Storage" provide agencies the authority to recommend for carbon capture and geologic sequestration. No Class VI-specific rules have been drafted.

Oil and Gas Regulations

All of the states researched have existing and mature oil and gas regulatory programs. CCUS projects, especially those in depleting oil fields, would likely need to adapt to existing oilfield spacing/pooling regimes. All of the states require EOR operators to obtain a permit from the state (with additional applications or notice to local jurisdictions in California, Indiana, and Oklahoma). Most of the states have minimum requirements for well spacing (i.e., from other producing wells or field boundaries) within a field. States may also have provisions for unitization of fields or pools (or parts thereof) to facilitate exploratory practices, increase oil or gas recovery, avoid the drilling of unnecessary wells, optimize the location of wells, and protect the rights of interested parties without increasing costs.

Few states have industrial siting regulations specific to CCUS-related activities (limiting these to hazardous waste facilities); however, Louisiana, Michigan, and Indiana provide specific siting criteria for oil and gas wells, which are typically related to the proposed depth of the well. Oil and gas facilities in Utah discharging contaminated storm water must obtain an industrial storm water permit.

Regulation of Oil and Gas Activities in the States

	Permitting	Spacing	Unitization
AL	All oil and gas wells require a permit, and drilling permits are subject to public notice and a hearing.	Spacing for wells is based on the size of the unit; wells in certain counties are subject to different rules.	Unitization is allowed if approved by the state.
CA	Approval from local authorities and the state is required to construct or modify a well. No reference to public hearings.	A well-spacing plan requires parcels of land to be pooled either voluntarily by interested parties; parcels may be pooled forcefully by the state.	The state may force or compel unitization and redesign of pressure plans if economically beneficial.
IN	All wells require a state permit; drilling within a city or town boundary requires consent from the local jurisdiction.	Generally, oil and gas wells cannot be drilled within a half-mile of an underground gas or petroleum storage facility.	Every lease of public lands must contain a clause authorizing the unitization of the land with other lands.
KS	Prospective oil or gas production well operators must obtain a permit from the state. No reference to public hearings.	Oil or gas wells may not be drilled less than 330 feet from any lease or unit boundary line, unless an exception is approved.	The state may order the unitization of a pool or part of a pool if it would be economically beneficial and equitable.
LA	A state permit must be obtained before drilling can begin. No reference to public notice or hearings.	Oil wells deeper than 3,000 feet must be at least 330 feet from a property line or 900 feet from other wells in the pool. (Similar spacing requirements for gas wells.) Shallow oil wells are not subject to spacing requirements.	The state has the authority to compel unitization.
MI	Prospective operators must obtain a permit from the state; public notice of the application is required.	Wells must be established on a drilling unit of a quarter-quarter section. The producing interval may not be within 330 feet of the drilling unit boundary.	Lessees may apply to the state for unit operation; the state may also compel unitization.
MS	Prospective operators must submit a permit application to the state; all oil and gas permits require public notice and hearing.	Rules relate to minimum drilling unit size and spacing from other wells within the same pool and the exterior boundary of the drilling unit.	The state may order unitization.

Regulation of Oil and Gas Activities in the States			
	Permitting	**Spacing**	**Unitization**
NE	Operators must receive approval from the state before drilling; while public notice is not specifically required, the applicant must identify owners in the field.	Well separations and subdivision size vary based on depth (i.e., deeper/shallower than 2,500 feet).	Operators may apply for unit operation.
OK	A permit is required prior to drilling, and public notice must be posted in a newspaper in Oklahoma County and in each county represented in the application.	Spacing requirements from property or lease lines and other wells exist (and vary based on depth) for vertical wells in the same source supply.	Forced pooling in spaced formations is allowed if applicants cannot form agreements with owners after notice and a hearing. This does not apply to overriding royalty interests, restricted Indian minerals, or State-owned minerals, however.
UT	All operators must submit an application and receive approval prior to drilling.	Generally, vertical wells must be at the center of a quarter-quarter section and be at least 920 feet from other wells in the same pool. Laterals of horizontal wells must be separated from drilling or spacing unit boundaries or other defined units.	Unitization of fields is authorized.

Class II Injection Regulations

All of the states studied, except Michigan, have Class II Underground Injection Control (UIC) Program primacy under Section 1425 of the Federal Safe Drinking Water Act (SDWA). All Class II well operators must obtain a permit and meet minimum standards to ensure that injection activities (including those that involve injecting CO_2 for EOR) do not endanger USDWs. In all of the states with primacy, the same state organization oversees injection and production wells.

Class II Injection Regulations in the States	
AL	The Alabama Oil and Gas Board has Class II UIC program primacy. Wells must be cased and cemented to prevent fluid movement to a USDW.
CA	The California Geologic Energy Management Division has Class II UIC program primacy. All onshore and offshore Class II well operators must demonstrate that injected fluids will not migrate from the injection zone. Operators must consult with local governments.
IN	The Indiana Department of Natural Resources has Class II UIC program primacy. Permit applicants must demonstrate that wells in the area of review (AoR) of the injection well are properly constructed or plugged and must provide notice to anyone with a surface or subsurface property interest within a quarter mile of the proposed well.
KS	The Kansas Corporation Commission has Class II UIC program primacy. The state's injection well regulations aim to protect USDWs from harm due to improper injection.
LA	The Louisiana Department of Natural Resources has primacy for Class I-V wells. Permits are required for all Class II injection wells, but permit application requirements differ for new and existing EOR projects.
MI	Michigan does not have Class II primacy, so all injection wells are overseen by EPA Region 5; Class II wells in Michigan are dually permitted by both EPA and the state (which has authority over the surface location).
MS	The Mississippi Oil and Gas Board has Class II UIC program primacy. All new Class II wells in Mississippi must have a permit, and applicants must demonstrate that there will be no endangerment of a USDW and give notice to all interested parties, the surface owner, and the operators of all wells in the pool.
NE	The Nebraska Oil and Gas Conservation Commission has Class II UIC program primacy. All Class II well operators must apply for a permit and notice of a Class II permit application must be provided to all interests near the injection well.
OK	The Oklahoma Corporation Commission has Class II UIC program primacy. A permit applicant must provide notice to each surface owner and surface lessee, as well as to the public.
UT	The Utah Department of Natural Resources has Class II UIC program primacy. Class II permit applicants must provide a copy of the permit application to all well operators and surface owners within one-half mile of the proposed injection well.

Environmental Rules

Environmental rules concerning CCUS will likely be adapted from existing oil and gas (O&G) well or injection well regulations, considering the technical similarities inherent to subsurface injection in oil fields. In addition to production and injection-related requirements, prospective CCUS project operators must adhere to a variety of other environment requirements, including but not limited to protecting drinking water sources, addressing potential concerns associated with induced seismicity, and preventing degradation of air quality.

In all of the states studied, injection and production wells must be constructed to protect ground water (typically via the cementing of at least one string of casing to the depth of the deepest identified drinking water layer). For injection wells, this layer is defined as a USDW (underground source of drinking water), and all states' rules have definitions that align with the minimum standard federal UIC definition of 10,000 mg/L TDS. Most states' production well regulations mirror this definition, with the exceptions of California, which defines fresh water as containing 3,000 mg/l TDS or less and Mississippi, whose O&G regulations do not designate a threshold TDS concentration.

The risk of injection-induced seismicity is typically evaluated in Class VI permits. Furthermore, some states (i.e., Kansas and Oklahoma) have developed risk-based seismic characterization and response plans that are based on the magnitude and frequency of seismic events, either state-wide or in high-risk areas. Nebraska requires a seismic risk assessment as part of the CCUS permitting process. Conversely, some states where induced seismicity is not a concern based on geology do not have induced seismicity provisions; Alabama, Indiana, Louisiana, Michigan, Mississippi, and Utah do not have any rules or guidelines for induced seismicity. California has no rules or guidelines specific to injection operations.

States' air quality regulations typically mirror the federal standards, with several states possessing standards specific to CO_2 emissions (i.e., California, Indiana, and Michigan).

Environmental Rules in the States			
	USDW/Fresh Water Definition	**Induced Seismicity**	**Air Quality**
AL	Definition of USDW for UIC and O&G wells matches the SDWA definition.	No state rules or guidelines for induced seismicity.	Air Pollution Control reporting rules explicitly exclude methane and CO_2.
CA	Fresh water is defined for O&G wells as water with 3,000 mg/L TDS or less. The UIC definition of USDWs is consistent with SDWA.	No state rules or guidelines for induced seismicity, other than for hydraulic fracturing.	Global Warming Solutions Act aims to reduce lowering GHG emissions; Public Utilities Commission rules aim to minimize methane leaks.
IN	Fresh water and USDWs are defined as water that contains no more than 10,000 mg/L TDS or less for UIC and O&G wells.	No state rules or guidelines for induced seismicity.	Required air permits/approvals for stationary sources that emit greenhouse gases address CO_2 and methane.
KS	Definitions for "freshwater" and "usable water" for UIC and O&G wells match the SDWA definition.	Kansas Seismic Action Plan describes an enhanced seismic monitoring network and response plan.	The state's broad definition of "air contaminant" does not identify CO_2 or methane directly.
LA	Definitions for UIC and O&G wells match the SDWA.	No state rules or guidelines for induced seismicity.	The state's broad definition of "air contaminant" does not identify CO_2 or methane directly.
MI	Definitions of "fresh water" or "mineral water" for UIC and O&G wells match the SDWA.	No state rules or guidelines for induced seismicity.	CO_2 and methane are both excluded from the definition of toxic air contaminants.

Environmental Rules in the States			
	USDW/Fresh Water Definition	**Induced Seismicity**	**Air Quality**
MS	The O&G regulations do not designate a threshold TDS concentration. The UIC rules define a USDW similar to the federal definition.	No state rules or guidelines for induced seismicity.	The state's ambient air quality standards follow the national air quality standards, and CO_2 is not listed.
NE	Definitions for UIC and O&G wells match the SDWA.	A seismic risk assessment is required as part of the GS permitting process.	Nebraska has adopted the federal emissions standards.
OK	Definitions of treatable water and fresh water (for O&G wells) and USDWs (for UIC wells) match the SDWA.	Arbuckle Formation projects must monitor and record injection volumes and pressures. Class II permit application reviews consider seismic history and proximity to faults. The state has begun designating "areas of interest" for seismic risk	The state Clean Air Act adopts the federal list of hazardous air pollutants. Localities with populations over 300,000 may enact more stringent air quality provisions, however.
UT	Definitions for UIC and O&G wells match the SDWA.	No state rules or guidelines for induced seismicity.	Utah rules incorporate federal emission standards for hazardous air pollutants for oil and natural gas production.

Water Rights

Riparian rights are the rights granted to landowners through which a natural watercourse runs, and are typically restricted to the use of surface water only. Conversely, appropriation is the authority granted by the state to file a permit and claim the use of natural water resources. Alabama, Indiana, Louisiana, and Mississippi adhere to a riparian rights system, whereas Kansas, Nebraska, Oklahoma, and Utah honor an appropriative rights system. California and Michigan observe both systems, and priority is dependent on the water source and use. In some cases (i.e., California), riparian rights will supersede appropriative rights, which will establish priority based on the date that the permit application was filed.

Riparian rights typically govern domestic uses of surface waters, including water for household purposes and livestock. Most states will have an order of preference for usage (i.e., industrial, agricultural, municipal) and maximum withdrawal or minimum streamflow limits, however some states (e.g., Oklahoma) may not honor a prioritization. Several states may restrict water usage during water emergencies, which is a potential concern as drought issues become more common.

Water Rights in the States		
	Surface Water Rights	**Ground Water Rights**
AL	Alabama statute declares that all waters of the state are basic resources. Declarations of Beneficial Use are required for systems that divert, withdraw, or consume more than 100,000 gallons of water a day from any of the state waters.	
CA	Riparian rights and appropriative rights apply, with riparian rights having priority, even in times of shortage. For appropriative rights holders, priority is established by application date.	California does not have a permit process for ground water use, but it is subject to regulation in several basins. Groundwater in California is also subject to the provision of reasonable use and uses the correlative rights doctrine; the state also imposes a proportionality rule.
IN	Riparian rights govern surface water use, based on minimum stream flow quantities.	The DNR can designate restricted use areas in places where the withdrawal of groundwater either exceeds or threatens to exceed natural replenishment. Withdrawals may be restricted in an emergency.
KS	The doctrine of prior appropriation for water administration applies. All waters within the state may be appropriated for beneficial use; however, the state also enforces minimum desirable streamflow requirements.	
LA	Louisiana adheres to a riparian rights system.	Groundwater ownership is considered similar to oil and gas, and is owned by nobody until it is acquired by a prospective user.
MI	Inland waters are governed by riparian rights. Diversions of waters from the Great Lakes requires registration and reporting. Any diversion of state waters requires legislative approval.	No specific rules on groundwater usage were identified.
MS	Mississippi is a riparian rights state. All uses of water require a permit, which automatically terminates after 10 years unless a renewal water permit is requested.	
NE	Nebraska is a prior appropriation state. Water rights are issued by the DNR and legally attach to a parcel of land.	Correlative rights govern Nebraska's groundwater usage. Landowners may drill wells and extract groundwater for beneficial purposes.
OK	Oklahoma is a prior appropriation state for surface water. Allowable uses for water appropriations include oil and gas exploration. Usage may be restricted in an emergency.	Groundwater in Oklahoma is considered the property of the surface owner, and any use other than domestic use requires a permit. Allowable usage may be limited based on determined annual yield.
UT	Utah is a prior appropriation state. Approvals for surface water and groundwater use are granted based on consideration of: the nature and extent of the use; priority date; the quantity of water to be diverted; the point and source of the diverted water; and the location of the beneficial use.	

Eminent Domain

Currently, Indiana, Louisiana, Michigan, and Mississippi have regulatory language regarding eminent domain as it relates to transporting CO_2 to storage reservoirs via pipelines. The majority of states presented in this research do not directly address eminent domain as it relates to CO_2; however, many states do possess eminent domain statute pertaining to oil and gas production and transportation. It is possible that CO_2 pipelines, particularly those used to transport CO_2 for EOR, would be considered common carriers and satisfy the public use requirement and allow for eminent domain. Condemnation procedures for eminent domain are typically conducted via the courts, with a valuation of the taken property determined by a judge or jury. In Oklahoma, private property, including minerals, cannot be taken without the owner's consent.

Eminent Domain Procedures in the States		
	Procedures for Condemnation	**Applicability to CCUS or Pipelines**
AL	Condemnation is conducted through the Probate Court with notice of the condemnation action in the Court's real property records. Following a hearing, the company must pay the determined condemnation judgment.	The right of eminent domain is conferred for "gas or electric works, pipelines, or any other work of internal improvement or public utility." CCUS is not specifically identified, however.
CA	Condemnation proceeds through the legislative body with jurisdiction over the project, and must be adopted at a public hearing and filed for in the court. The landowner can either accept or reject the offer by claiming that it will have no public benefit or the proposed price is unfair.	No eminent domain provisions specifically address CO_2 pipelines or underground storage; however, a pipeline company transporting CO_2 from multiple sources to a storage site would likely be designated a common carrier, and be able to exercise eminent domain.
IN	Exercising eminent domain requires a certificate of authority. Compensation above fair market value is required, with the amount dependent on the type of landowner.	Indiana has explicit eminent domain requirements for CO_2 pipeline transportation companies and for the underground storage of CO_2.
KS	To exercise their right to eminent domain, a company must file a petition that must be verified in the county district court, followed by an appraisal. Compensation is based on how much of the land is taken and for what purpose.	Kansas does not seem to have any special eminent domain provisions specifically addressing CO_2 pipelines or underground storage. However, it is likely that oil and gas transportation pipelines, which are common carriers under Kansas Statutes, may satisfy the public use requirement.
LA	The condemner must file a petition in the district court, where expropriation cases are generally tried without a jury, unless the plaintiff and defendant dispute the amount of compensation.	The Geologic Sequestration of Carbon Dioxide Act dictates eminent domain laws for operation and transportation of CO_2 to storage facilities. Property can also be expropriated for the underground storage of CO_2.
MI	Condemnation requires negotiation of a purchase price and "explicit authorized acceptance" with the Michigan Public Utilities Commission.	Oil, petroleum, or CO_2 pipelines are common carriers under Michigan law and may exercise eminent domain.
MS	Condemnation proceeds through the county courts; a jury determines the compensation amount.	Companies operating pipelines transporting CO_2 for use in connection with EOR can exercise eminent domain.
NE	Petitions for eminent domain proceedings are filed in the county court, which is then filed by the State Attorney General on behalf of the Department of Transportation. Judge-appointed appraisers determine the property value and any damages.	Any company transporting or conveying gas through or across the state is declared a common carrier and may exercise eminent domain. Eminent domain as it relates to CO_2 storage has not been addressed, but CO_2 storage could qualify as a public interest.
OK	Private property cannot be taken without consent of the owner. The judiciary determines the "character of the use" for all condemnation cases.	The ability to exercise eminent domain for pipelines is limited, and does not address CO_2 pipelines.
UT	Property may be taken if the court determines that: the use is authorized; the taking is necessary; and the use will commence within a reasonable time.	Eminent domain is authorized for gas and oil pipelines, although no rules or statutes specific to CO_2 storage were found.

Mineral Rights

Most of the states' definition of a "mineral" include oil, natural gas, or any naturally-occurring substance in subsurface strata. For the majority of states, it is unclear if CCUS operators must own the surface rights, mineral rights, pore space, or a combination of such in order to lawfully sequester CO_2. However, a few states specifically address ownership of stored CO_2. In Louisiana and Mississippi, the ownership of CO_2 does not change when it is injected. In Nebraska, ownership of CO_2 is transferred to the state upon site closure, after which the state assumes responsibility for long-term monitoring and liability.

Most states possess the ability to sever mineral rights from the surface estate, resulting in a split estate. The exception is Louisiana, where landowners may still convey, reserve, or lease the right to explore and develop land for mineral production. In most cases of a split estate, the mineral estate is dominant over the surface estate. The owner of the mineral rights will typically have access to the surface estate to extract the minerals, provided the surface owner is compensated. However, a few states restrict this right of access—in Oklahoma, oil and gas operators must pay surface damages resulting from their operations, and in Utah users must minimize interference with the surface owner's use of the land. There are also some states that do not establish mineral dominance (e.g., Kansas), but still provide an implied right to use of the surface estate to develop the land. In many states, the dominant estate statue usually develops along with the reasonable use doctrine, which either expressly or implicitly conveys the right of a lessee to use all of the surface estate that is reasonably necessary to carry out their operations under the lease. Many states also have dormant mineral rights clauses, meaning if the title to minerals is not used for a given time period (i.e., 10 to 20 years of inactivity), the mineral rights revert to the surface owner.

Mineral Rights in the States

	Ownership	Is the Mineral or Surface Estate Dominant?
AL	In general, real estate is taken as fee simple unless expressly limited.	Not specified.
CA	California defines "mineral rights" as interest in minerals created by grant or reservation.	Mineral estates are viewed as dominant when separated from surface estates.
IN	A mineral interest (i.e., in coal, oil and gas, or other mineral) can transfer ownership in the same manner as other real estate.	Not specified.
KS	A "mineral interest" is an interest in coal, oil, gas or other minerals that can be transferred, granted, etc.	Kansas confers an implied right to use of the surface estate in developing the land.
LA	Ownership of land in Louisiana does not include ownership of oil, gas, and other minerals; thus landowners in Louisiana do not own the minerals under their land unless they are acquired.	Louisiana law does not provide for the separation of mineral estates from the land. The landowner can convey, reserve, or lease the right to explore and develop land for the production of minerals.
MI	Mineral rights are considered a type of real property that can be owned with, or separately from, surface rights. If severed, both the mineral and the surface rights become freehold estates in fee simple.	If severed, the mineral rights become dominant and the surface subservient.
MS	Mineral interests can be conveyed or listed as a reservation on the surface title when it is conveyed.	The mineral estate is dominant over the surface estate.
NE	Mineral rights are vested property rights that can be created through a conveyance, reservation, or exception on title.	When severed, the mineral estate becomes dominant and the surface subservient.
OK	Mineral rights represent a right to capture the minerals underlying real property, but the minerals themselves are not "owned" until they are captured.	Courts have historically held that the mineral estate is considered the dominant estate. Oil and gas operators must pay surface damages resulting from their operations.
UT	Mineral rights are considered a type of real property that are held in fee simple title. They can also be severed to create a mineral estate and a surface estate.	The mineral estate is considered dominant to the surface estate, but users must minimize interference with the surface owner's use of the land.

Pore Space Ownership

Pore space is typically implied in state statute as subsurface space that is devoid of minerals. The majority of the states studied do not explicitly discuss pore space ownership, nor do they discuss implied rights of the mineral or surface estate owner to that space. Instead, pore space ownership to either the surface or mineral owner has been interpreted in past court rulings.

A couple of states have directly addressed pore space ownership as it relates to CO_2 storage. Mississippi requires CO_2 geologic sequestration facility operators to obtain approval from the majority interest of surface and subsurface owners. In Nebraska, the title to any subsurface reservoir is owned by the surface owner, unless it was previously severed. Pore space ownership has not been addressed in Alabama, Indiana, or Utah.

Pore Space Ownership in the States	
AL	Not addressed.
CA	Property law discussing the difference between mineral rights and pore space rights is ambiguous in California. Ultimately, the party interested in acquiring pore space rights may need to negotiate with both surface and mineral estate owners to obtain surrounding subsurface pore space.
IN	Not addressed.
KS	Kansas has not yet addressed the issue of pore space ownership by statute. However, case law has been cited to support the conveyance of pore space rights to the mineral estate.
LA	Louisiana has not yet specifically addressed pore space ownership. However, past court opinions have supported the surface owner's right to the pore space beneath the property.
MI	Michigan has not yet specifically addressed pore space ownership. However, past court opinions have supported the surface owner's right to the pore space beneath the property.
MS	CO_2 sequestration facilities must obtain approval from the majority interest of surface and subsurface owners.
NE	Title to any reservoir estate underlying the surface of lands/waters lies vested in the surface owner, unless it was previously severed.
OK	The legislative and the judicial branches of Oklahoma have both determined that pore space ownership lies with the surface owner.
UT	Not addressed.

ALABAMA

Executive Summary

There is significant potential storage capacity for CO_2 in Alabama in the state's oil and gas reservoirs, saline formations, and in coal seams, and current CCUS research is focused on CO_2 storage for enhanced methane recovery from coal beds. The state adopted draft rules for CO_2 storage facilities that included requirements for Class VI injection wells, but has not applied to EPA for primacy. The lack of CO_2 pipeline infrastructure is a potential challenge for CCUS.

Background

Alabama includes federal, state, fee simple, and tribal land. Of the state's 32,678,400 acres, the federal government owns 880,188 acres, or 2.7%. There are 9 tribes in the state, but the Poarch Creek reservation is the only federally-recognized reservation.[1] This reservation includes off-reservation trust land in both Alabama and Florida.[2] Additionally, the MOWA Choctaw Reservation is a state-recognized reservation. From 1984-1985, approximately 232 acres of land were taken into trust and 230 acres were declared a Reservation.[3] The remaining tribal entities are known as state designated tribal statistical area - statistical entities for state recognized American Indian tribes that do not have a land base. The Alabama Indian Affairs commission acts as the liaison between the tribes and the government departments.

Alabama's judicial system operates under common law. The system hosts 67 district courts, 280 municipal courts, and 68 probate courts.[4] All appeals go to the 41 circuit courts; from there, appeals are taken to the 4 judges in the court of criminal appeals or the 5 judges in the court of civil appeals, who will review the actions and decisions of the trial courts.[5] The highest state court is the Supreme Court, composed of 1 chief justice and 8 associates. There is no special court for water or mineral rights disputes.

The Alabama Department of Environmental Management (ADEM) acts as the primary regulatory body for environmental issues, and is the agency that is developing rules for Class VI (CO_2) injection wells.[6] The Alabama Oil and Gas Board (OGB) is responsible for preventing waste and "promoting the conservation of oil and gas while ensuring the protection of both the environment and the correlative rights of owners."[7] In doing so, the Department enforces rules and regulations to ensure conservation and proper development of the state's petroleum resources. Authority is granted through state statute. Additionally, the OGB oversees oil and gas production wells and Class II

[1] Alabama Indiana Affairs Commission. *Tribal Map*. Available at: https://aiac.alabama.gov/Tribal-Map.aspx.

[2] Tribal Geography in Relation to State Boundaries. Available at: https://www.cdc.gov/tribal/tribes-organizations-health/tribes/geography.html.

[3] History of the Poarch Band of Creek Indians. (2005). *Poarch Creek Indians*. Accessible at https://web.archive.org/web/20100727182713/http://poarchcreekindians.org/xhtml/culture.htm.

[4] Alabama Judicial System. Available at www. https://judicial.alabama.gov/Appellate/Index.

[5] Ibid.

[6] ADEM Admin. Code r. 335-6-x-.xx

[7] GSA/OGB. GSA/OGB Home. Available at: https://ogb.alabama.gov/.

injection wells. The OGB is partnered with the Geological Survey of Alabama (GSA); both maintain data related to oil and gas production in the state by field and plant.[8]

CCUS Activities in the State

Alabama's history of oil and gas exploration dates back to 1944, when the state's first oil and gas well was drilled in Gilbertown, AL. This was the catalyst for significant expansion of oil and gas exploration in Alabama, leading to the establishment of the State OGB in 1945.[9]

According to the OGB, total oil production for 2018, the most recent year with aggregated data, was 5,883,523 barrels, and total gas production in 2018 was 140,246,799 mcf (thousand cubic feet).[10] Annual oil production has averaged about 8.5 million barrels over the last 20 years.[11] As of July 23, 2021, there are 19,002 producing oil and gas wells in Alabama[12] and over 450 oil fields in the state, according to GSA records. According to US EPA data, there are Class II injection wells in Alabama, including 89 wastewater disposal wells and 188 EOR wells.[13]

In 2018, CO_2 emissions for Alabama totaled 113.3 million metric tons of CO_2, including 35.9 million metric tons from coal, 36.4 million metric tons from petroleum, and 40.9 million metric tons from gas.[14] DOE estimates that a total of between 122.20 and 694.16 billion metric tons of CO_2 storage capacity are available in Alabama. This includes 0.06 to 0.12 billion metric tons in oil and gas reservoirs, between 1.92 and 4.37 billion metric tons in unmineable coal storage, and between 120.22 and 689.67 billion metric tons in saline formations.[15]

Current research into CCUS is focused on injection of CO_2 sourced from coal fired power plants for enhanced methane recovery from coal beds, as well as EOR.[16] GSA and DOE's National Energy Technology Laboratory (NETL), have been at the forefront of research into Alabama's potential for CCUS. Much of this research has been in coordination with the Southeastern Regional Carbon Sequestration Partnership (SECARB). The "Geologic Screening Criteria for Sequestration of CO_2 in Coal" study was commissioned by the DOE in 2000 to document screening criteria for CCUS site selection in Alabama's Black Warrior Basin coalbed methane (CBM) fairway. This paper concluded that enhanced CBM recovery is technically feasible and has substantial potential in the Black Warrior Basin of Alabama. The study notes, however, that CO_2 injection and recovery where the coal beds are shallow (i.e., near 2,000 feet below the surface and contain fresh water with TDS content of less than 3,000 mg/L) and or contain fault zones are not attractive for CO_2 injection and enhanced CBM recovery. [17]

Crude oil and natural gas fields are found in the Black Warrior Basin in the north-west and the Interior Salt Basin in the south-west. One source estimates that the Black Warrior Basin may have the

---

[8] GSA/OGB. Available at: https://ogb.alabama.gov/.

[9] Rural SW Alabama. First Oil Well in Alabama Gilbertown, AL. Available at: https://www.ruralswalabama.org/attraction/first-oil-well-in-alabama/.

[10] GSA/OGB. Calendar Year Total Production. Available at: https://www.gsa.state.al.us/img/ogb/summaries/AnnStateCalPrd.pdf.

[11] Ibid.

[12] Mineral Answers. Alabama Well and Production Data. Available at: https://www.mineralanswers.com/alabama.

[13] EPA. UIC Injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.

[14] US Energy Information Association. State Carbon Dioxide Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.

[15] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[16] GSA/OGB. Carbon Capture, Use, and Storage (CCUS) Research. Available at: https://www.gsa.state.al.us/gsa/energy/coal/co2.

[17] Geologic Screening Criteria for Sequestration of CO2 in Coal. Available at https://www.gsa.state.al.us/gsa/energy/alt/co2/quantifyingpotential.

capacity to store 28 billion metric tons of CO_2.[18] Another recent assessment estimated that about 340 million metric tons of CO_2 can be stored in established coalbed methane fields,[19] many of which are found near large coal and methane reserves in central Alabama.[20]

GSA worked with industry partners on studies of CO_2-EOR at the Citronelle Oil Field in Mobile County, Alabama. As part of this study, CO_2 was injected through an infill well into two sands at depths near 11,000 feet. The Citronelle Dome is estimated to have capacity to store 480 to 1,905 million short tons of CO_2, enough to store the CO_2 produced from coal-fired generation at nearby Power Plant Barry (12 million tons/year) for at least 40 years.[21] Plant Barry was considered for a CO_2 Capture and Storage Project, and pilot-scale injection into the Paluxy saline formation at the Citronelle oil field began in 2012; however, the Citronelle project was discontinued.[22]

A network of pipelines delivers crude oil to the state's three refineries from instate as well as Texas and Louisiana (through the Colonial and Plantation Pipelines). The largest refinery is located near Mobile, the second-largest is in Tuscaloosa on the Black Warrior River, and the third in Atmore. The three refineries have a combined processing capacity of 142,000 bbl per day.[23] Although Alabama does not appear to have an extensive CO_2 transportation pipeline infrastructure, there is potential for development through connection with CO_2 pipelines in neighboring Mississippi.[24]

Classification of CO_2: Commodity

Alabama imposes several types of taxes on activities that generate CO_2, which appears to imply that the state considers CO_2 to be a commodity. Exclusion of CO_2 from its air pollution control rules means the state does not consider it to be a pollutant.

Alabama statute imposes a severance tax on the purchaser of all severed materials[25] severed from the ground and sold as tangible personal property.[26] The exception to this rule is that no tax can be due on minerals that are sold to a purchaser for use outside the state, provided they are not transported on public roads in Alabama. The state also imposes an annual privilege tax upon every person engaging in the production or severance of oil[27] and gas[28] from or beneath state soil and water for the purpose of "sale, transport, storage, profit, or use."[29] This tax is measured at a rate of 8% of the gross value of the oil/gas at

[18] Department of Energy. DOE-Sponsored Drilling Projects Demonstrate Significant CO2 Storage at Three Sites. Available at: https://www.energy.gov/fe/articles/doe-sponsored-drilling-projects-demonstrate-significant-co2

[19] Cited as 5.9 trillion cubic feet in, "Potential Geologic Carbon Sinks." Available at: https://www.gsa.state.al.us/gsa/energy/alt/co2/secarb1.

[20] US Energy Information Association. Alabama State Energy Profile. Available at www.eia.gov.

[21] Ibid.

[22] Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project. Available at: https://sequestration.mit.edu/tools/projects/plant_barry.html.

[23] US Energy Information Administration. Alabama quick facts. Downloaded on July 23, 2021 from https://www.gsa.state.al.us/gsa/energy/alt/co2/secarb1.

[24] U.S. DOE. A Review of the CO_2 Pipeline Infrastructure in the U.S. Available at: https://www.energy.gov/.

[25] "Severed material," as referred to in Section 40-13-51, refers to all natural minerals, including, but not limited to, sand, gravel, sandstone, granite, shale, clay, except clay that produces lightweight aggregate, dolomite, and limestone. Oil and natural gas are listed as an exception in 40-13-53.

[26] AL. Code, Section 40-20-2.

[27] "Oil" refers to crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the well in liquid form by ordinary production methods and which are not the result of condensation of gas after it leaves the well.

[28] "Gas" refers to all natural gas, including casinghead gas, and all other hydrocarbons not defined as oil.

[29] AL. Code, Section 40-20-2.

the point of production; unless it was produced from an enhanced recovery project[30] or unless the wells produced 25 barrels or less of oil per day (or 200,000 cubic feet of gas per day or less), in which the rate is 4%. All oil or gas produced, all leases in production (including mineral rights in producing properties), and all oil or gas under the ground on producing properties are nevertheless exempt from ad valorem taxes by the same statute.[31]

The state further imposes a transfer tax known as a "mineral documentary tax" upon the filing and recording of every lease that creates a leasehold interest in or to any nonproducing oil, gas or other minerals.[32] However, the state does provide for an exemption of this tax upon existing interests.[33]

Alabama statute does provide for an exemption from taxation for storage operators regarding the production, severance, extraction, and withdrawal of gas injected into a storage facility. However, this exemption is seemingly held for hydrocarbons, and for cases in which the gas is extracted or withdrawn from the storage facility.

Alabama statute does not specifically list CO_2 as an air pollutant and appears not to regulate it as part of the State's Air Pollution rules. ADEM's Air Pollution Control rules require reporting of emissions and appear to specifically exclude CO_2 from the rules related to "Control Of Organic Emissions,"[34] per the definition of Volatile Organic Compounds, which means "…any compound of carbon excluding carbon monoxide, carbon dioxide…which participates in atmospheric photochemical reactions."

Furthermore, Alabama statutes also contain a "Kyoto protocol response" that calls for the Director of ADEM to refrain from proposing or promulgating any "new" regulations (after 1997) intended to reduce emissions of greenhouse gases defined by the Kyoto Protocol, from the "residential, commercial, industrial, electric utility, or transportation sectors unless such reductions are required under existing statutes."[35] Our research has not found anything about the presence of carbon credits in the state.

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

CCUS-related activities are regulated by the State OGB (which regulates oil and gas production and Class II injection activities) and by ADEM (which regulates pipelines and has proposed draft rules for Class VI wells). No tribal or local laws or regulations address CCUS-related activities within the state.

Pipeline Regulations

According to Alabama statute, pipelines are regulated by ADEM, although inspection and monitoring are performed by the Alabama Public Service Commission (APSC) in partnership with the US Pipeline & Hazardous Materials Safety Administration's Office of Pipeline Safety (OPS).[36, 37]

The APSC issues safety compliance notices to pipeline operators, beginning a process of consultation between the APSC and the operator to determine a plan to address the risk factors associated with the pipe. The operator may request a hearing, where the individual risk factors associated with the pipeline in question are considered including pipe characteristics (age, manufacturer, corrosion resistance,

[30] "Oil, gas, and minerals" refers to oil, gas, petroleum, hydrocarbons, distillate, condensate, casing-head gas, other petroleum derivatives and all other similar minerals of commercial value which are usually produced by the drilling, boring or sinking of wells.

[31] AL. Code, Section 40-20-12.

[32] AL. Code, Section 40-20-31.

[33] AL. Admin. Code, Section 40-20-36.

[34] ADEM Admin. Code r. 335-3-6.

[35] AL. Code, Section 22-28A-3.

[36] ADEM. Water Division - Water Quality Program Vol. 1 Division 335-6 (ADEM Admin. Code r. 335-6-8)

[37] APSC Gas Pipeline Safety Overview. Available at www.alabama.gov.

or deterioration), nature of materials transported, proximity of the pipeline to "unusually sensitive or high consequence areas," and population density of the area.[38]

APSC's inspection and monitoring jurisdiction applies to all gas and hazardous liquid pipeline systems operating in Alabama, including offshore drilling facilities in state waters.[39] Based on the definition of hazardous liquid pipelines as any, "…substance or material which is in liquid state, including liquified natural gas (LNG), when transported by pipeline facilities and which may pose an unreasonable risk to life or property when transported by pipeline facilities,"[40, 41] it appears that this jurisdiction does not apply to transportation of gaseous CO_2. According to the APSC website, APSC currently regulates 98 intrastate gas systems, 34 master meters, eight hazardous liquid systems, one liquefied petroleum system, five liquefied natural gas systems, and four offshore systems.[42]

Laws and Regulations for CO_2 Storage

ADEM adopted draft rules for CO_2 storage facilities that included requirements for Class VI injection wells[43] under the Alabama Water Pollution Control Act (AWPCA), which are contained in the Water Quality Program's rules for Protection of Water Quality. Alabama's Class VI rules include requirements for area of review delineation, corrective action, financial responsibility, construction, logging, sampling, testing, operation, mechanical integrity, monitoring, reporting, plugging, post-injection site care, site closure, well emergency and remedial response.[44] Alabama has not been granted Class VI program primacy by EPA; therefore any Class VI wells in Alabama are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 4.

Regulation of Oil and Gas Production

Alabama's requirements for oil and gas wells are found in the "Rules and Regulations Governing the Conservation of Oil and Gas in Alabama," known as the "Gold Book." The regulations are promulgated under the authority of Title 9, Chapter 17 of The Code of Alabama.

All oil and gas wells require a permit.[45] Operators must submit to the OGB a permit application that includes information about the well, including siting, depth, details about the proposed operation, and the well's construction. The applicant must also provide a financial assurance bond that is based on the depth of the well. All drilling permits are subject to public notice and a hearing. The rules also contain requirements for appropriate cementing and casing to protect freshwater resources. Drilling may not commence without approval from the Supervisor.

Wells drilled from onshore surface locations where the bottom hole location is offshore must be permitted, drilled, completed, and plugged pursuant to onshore rules, but are subject to spacing requirements for offshore facilities. The OGB's regulations governing submerged offshore lands operations at A.A.C. 400-2 apply to oil and gas operations conducted in submerged offshore lands. Operators involved on offshore lands are also subject to the UIC regulations and the Procedures for Forced Integration or Forced Pooling (at 400-7-1-.01).

Depending on size, wells may not be drilled nearer than 330 feet (for an approximately 40-acre unit) or 660 feet (for an approximately 160 acre unit) from any lease or unit boundary line, unless an

---

[38] Ibid

[39] APSC Gas Pipeline Safety Overview. Available at www.alabama.gov.

[40] APSC. Alabama Public Service Commission Rules and Regulations for Gas Pipeline Safety.

[41] AL. Code, Section 37-4-90.

[42] Ibid.

[43] ADEM Admin. Code r. 335-6-8; issued under statutory authority of Alabama 1975, §§ 22-22-9, 22-22A-5, 22-22A-6, 22-22A-8. Effective February 15, 2021.

[44] ADEM. Water Division - Water Quality Program Vol. 1 Division 335-6 (ADEM Admin. Code r. 335-6-8)

[45] 400-1-2-.01.

exception is approved.[46] There are some notable exceptions to the rule based on the proposed location of drilling, specifically in Fayette, Lamar, Pickens, Tuscaloosa, Baldwin, Escambia, Mobile, and Washington counties. [47]

Unitization of fields is determined to be appropriate if OGB finds that it is necessary to prevent waste, to increase oil or gas recovery, avoid the drilling of unnecessary wells, optimize the location of wells, and to protect the correlative rights of interested parties, without increasing the cost of recovering the additional oil or gas. All unitization agreements must be incorporated into leases as amendments and approved by the Commissioner of Conservation and Natural Resources and signed by the Governor.[48]

Regulation of Injection Activities

Alabama has Class II UIC program primacy under Section 1425 of the SDWA, granted on August 2, 1982 to the OGB.[49] The UIC Rules are in the Alabama Administrative Code at 400-4. Owners or operators of Class II wells must obtain a permit, and submit an application that describes drilling, completion, or conversion procedures for the proposed injection well; wellbore schematics; information on the deepest USDW; an AoR study; and information on the fluids to be injected. Wells must be cased and cemented to prevent fluid movement to a USDW, as demonstrated by a cement bond log or the results of a fluid movement study.

All Class II well permits are subject to public notice and comment. Following issuance of the permit, owners or operators are subject to requirements for proper operation to maintain mechanical integrity, monitoring, and reporting.

Environmental Laws

In the ADEM's UIC regulations for Class I, III, V, and VI wells and the oil and gas/Class II regulations, USDWs are defined similar to the federal definition (i.e., containing less than 10,000 mg/L TDS).[50] The casing and cementing requirements for oil and gas wells require owners or operators to "case and cement all wells with a sufficient number of strings in a manner necessary to… prevent contamination of freshwater-bearing strata."[51] Fresh water is not defined, however.

The rules for coalbed methane gas operations require a permit, and contain provisions for spacing of wells (i.e., by special field rules for that particular field), and adequate construction to protect freshwater resources.[52]

The rules for Protection of Water Quality also address water pollution control, the National Pollutant Discharge Elimination System (NPDES), water quality criteria, and water use classifications for interstate and intrastate waters, which classifies specific waters according to their use (e.g., Outstanding Alabama Water, Public Water Supply, Swimming, Shellfish Harvesting, Fish and Wildlife, and Agricultural and Industrial Water Supply).[53]

The Alabama Air Pollution Control Act of 1996 defines "air contaminant" as "any solid, liquid or gaseous matter, any odor or any combination thereof, from whatever source" and "air pollution" as "the presence in the outdoor atmosphere of one or more air contaminants in such quantities and duration as are, or tend to be, injurious to human health or welfare, animal or plant life or property or would interfere

---

[46] State Oil and Gas Board of Alabama Administrative Code. Available at https://www.gsa.state.al.us/gsa/energy/alt/co2/secarb1.

[47] Ibid.

[48] Acts 1956, 1st Ex. Sess., No. 158, p. 224, § 5; Acts 1982, No. 82-622, p. 1177, § 1.

[49] 47FR33268.

[50] AL Admin Code. 335-6-8-.02; 400-1-4.

[51] AL Admin Code. 400-1-4-.09.

[52] AL Admin Code. 400-1-3.

[53] ADEM Admin. Code r. 335-6.

with the enjoyment of life or property throughout the state and in such territories of the state as shall be affected thereby." The Act also grants ADEM the authority to establish emission control requirements to maintain "appropriate" levels of air quality and protect human health and safety. As noted under "Classification of CO_2: Commodity" above, it does not appear that CO_2 is a regulated pollutant in Alabama. ADEM's Air Pollution Control rules that require reporting of emissions explicitly exclude methane (in addition to CO_2) from the rules related to "Control of Organic Emissions."[54]

Induced seismic activity associated with injection activities does not appear to be a concern in Alabama, based on the GSA's "Earthquakes in Alabama" web page, and the State does not have rules addressing seismicity for injection or production wells.

Industrial Siting Requirements

Our research did not identify any statutes or regulations that govern the siting of oil and gas fields, pipelines, or energy utilities in Alabama.

Eminent Domain

Alabama authority for eminent domain is outlined by Alabama statute and in the Alabama constitution. Two sections in the Alabama Constitution specifically pertain to the power of eminent domain and to condemnation actions. Article 1, Section 23 of the Alabama Constitution, states that the legislature may secure the right of way to individuals or corporations over the lands of other individuals or corporations, but that "private property shall not be taken for, or applied to public use, unless just compensation be first made therefore… or without the consent of the owner."[55] This section applies to the State of Alabama as well as to all those who are delegated the power of eminent domain from the State. The second section only pertains to individuals or entities with the delegated power of eminent domain, and therefore does not apply to the State itself. However, it too grants municipal entities, corporations, and individuals the privilege of taking property for public use, under the condition that just compensation will be made prior to taking, injuring, or destroying the property in question.[56]

Alabama does not have a statutory definition for "public use," instead passing this on to the court system. According to the Huntsville Bar Association, Alabama courts have consistently stated that this term should be given a "liberal and elastic" meaning for governmental and non-governmental entities.[57] The courts have also decided that public utility companies qualify as public use because their projects are of benefit to the public.[58] The legislature has additionally conferred the right of eminent domain on counties and municipal corporations, as well as corporations formed for the purpose of constructing, operating, or maintaining, "gas or electric works, water companies…pipelines, or any other work of internal improvement or public utility."[59]

The procedure for condemnation of property under the power of eminent domain is governed by the Alabama Rules of Civil Procedure, and the process itself is found in the Alabama Eminent Domain Code.[60] Before a corporation can file a condemnation complaint, the property must be inspected and appraised to determine "just compensation" for its taking.[61] If there is only a partial taking of the property, the valuation rule is the difference between the fair market value of the entire property before

---

[54] ADEM Admin. Code r. 335-3-6.
[55] Alabama Constitution, Art. I, Sec. 23.
[56] Alabama Constitution, Art. XII, Sec. 235.
[57] James A. Bradford. A Primer on Alabama Eminent Domain and Condemnation Law. Huntsville Bar Association.
[58] Alabama Power Co. v. Hamilton, 342 So. 2d 8 (Ala. 1977); Opinion of the Justices, 48 So. 2d 757 (Ala. 1960).
[59] Ala. Code, Sec. 10-5-1.
[60] AL Admin Code. 18-1A-70.
[61] AL. Admin Code. Section 18-1A-21.

the taking and the fair "market value"[62] of the remainder after the taking.[63] Except in an emergency, a condemner may not force the owner property to move unless they have received written notice from the condemner at least 90 days before the required move date.[64]

The process of gaining the right of possession begins with the company filing a condemnation action in the Probate Court where the property is located. In addition, the company must file a notice of the pendency of the condemnation action in the Court's real property records.[65] The Court will hold a merit hearing on the condemner's right of taking, and, if the condemner prevails, they will participate in a valuation hearing to obtain a judgment of condemnation and pay the condemnation judgment.[66]

Section 9-17-154 details eminent domain for underground storage of gas.[67] Under this section, storage operators must obtain board approval to exercise eminent domain and acquire all surface and subsurface rights and interests for operating the storage facility. This includes easements and rights-of-way across lands for transporting, by pipeline or otherwise, gas to and from the facility.

At present, Alabama's statutory definition for a public utility does not appear to include the usage of eminent domain statutes to acquire pore space from property owners.

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

In Alabama, a mineral interest is considered to be real property.[68] In general, real estate is taken as fee simple unless expressly limited,[69] and all conveyances of property must be recorded.[70]

Alabama does not seem to provide any statutory authority regarding the conveyance of mineral rights through a deed, although they do provide for guidance on the acquisition of a mineral lease. Code of Ala. § 9-17-60 states that the Commissioner of Conservation and Natural Resources, on behalf of the state, is authorized to "lease any lands or interest therein under the jurisdiction of the department of conservation and natural resources for the exploration, development, and production of oil, gas and other minerals or any one or more of them, on, in and under such lands."[71] The commissioner can also lease any land owned by a state department, institution or agency upon the written request of their respective heads.

Any revenues that accrue from rentals, royalties, or other sources subject to the cost of administration become the property of the department or institution that the lands belong to or owns the beneficial interest.[72] Any lease executed under the provisions of the Department of Conservation and

[62] The fair market value is defined as the price the property would bring when offered for sale by a willing seller who is not forced to sell and which is sought by a willing buyer who is not required to buy, after due consideration of all the elements affecting value. (Section 18-1A-172)

[63] AL Admin Code. 18-1A-170.

[64] AL Admin Code. 18-1A-24.

[65] § 18-1A-75(a).

[66] § 18-1A-276.

[67] "Gas" refers to All natural gas, casinghead gas, and occluded natural gas found in coal beds, and all other hydrocarbons not defined as oil in Section 9-17-1(3), except and not including liquid petroleum gas. (Section 9-17-150).

[68] *Nelson v. Teal*, 293 Ala. 173, 301 So.2d 51 (1974).

[69] Section 35-4-2.

[70] Section 35-4-50.

[71] Section 9-17-60.

[72] Section 9-17-68.

Natural Resources can authorize the lessee to pool or unitize the lease, the lands or minerals covered, or any part thereof with other lands, leases or mineral estates, upon the approval of the Commissioner.[73]

Alabama courts would employ rules of construction to ambiguous mineral contracts in determining if the definition of the word "mineral" is ambiguous.[74] If it is ambiguous and the meaning of that clause is doubtful, they would have to construe the clause so as to resolve the doubts in favor of the grantees and against the grantor.

Given the lack of statutory guidance, our research did not identify the definition of a mineral, or pore space ownership.

Split Estates

Alabama does not statutorily provide for any severability provisions. However, severability is addressed in *Alabama Fuel Iron Co. v. Broadhead*. Here, it is established that mineral and surface rights can be severed, although adverse possession, or occupation of the mineral of land, for 10 years also provides the respective title of the land. Additionally, possession of the mineral right follows possession of the surface, unless severed.[75] The effect of severance creates two "adjoining but separate" estates, where possession of one does not equal possession of the other.[76] If the owner of a mineral estate does not own the surface land, however, they must get permission from the surface owner to disturb the surface in order to mine the minerals.[77]

Pore Space Ownership

Our research did not identify any Alabama guidance on determining ownership of pore space or sub-surface space.

Water Rights

Alabama statute declares that all waters of the state, including on the surface and in the ground, are considered to be basic resources of the state, and that they should be conserved by the doctrine of beneficial use.[78] Human consumption of water is recognized as a state priority under state law, especially in times when water usage in the area exceeds supply.[79]

Water rights are managed under the Alabama Water Resources Act and overseen by both the Water Resource Commission and the Office of Water Resources in the Alabama Dept of Economic and Community Affairs.[80] Generally, neither the Commission nor the Office of Water Resources can restrict a person's beneficial use of state waters. The exception is if the Commission finds that the area will not have enough water supply capacity for current or future usage, in which "stress capacity areas" can be designated.[81] Additionally, Riparian landowners are not affected by the water use statutes.[82]

Alabama statute also provides for a "Declarations of Beneficial Use" for systems who divert, withdraw, or consume more than 100,000 gallons of water a day from any of the state waters. For those under 100,000, declarations are not required. The declaration must acknowledge the estimated amount, in gallons per day, of the waters of the state used on an annual average daily basis, as well as the estimated

[73] Section 9-17-63.

[74] *Martin v. Knight*. 275 So. 2d 117 (1973).

[75] ALABAMA FUEL IRON CO. v. BROADHEAD, 210 Ala. 545 (1924).

[76] Whitehead v. Hester, 512. So. 2d 1297 (1987).

[77] *Bibby v. Bunch*, 176 Ala. 585, 589, 58 So. 916, 917 (1912).

[78] Alabama Code 9-10B-2 (1).

[79] Alabama Code 9-10B-2 (4).

[80] Alabama Code 9-10B-4.

[81] Alabama Code 9-10B-2 (6).

[82] Alabama Code 9-10B-27.

capacity, in gallons, that they diverted, withdrew, or consumed per day.[83] The Office of Water Resources will in turn issue a certificate of use acknowledging the estimated amount, which will last for the life of the facility, not to exceed 40 years.[84]

Lithium Ownership and Extraction

Our research did not identify any lithium mining operations in Alabama or specific requirements related to lithium extraction or the presence of lithium in produced waters.

[83] Alabama Code 9-10B-19 (4).
[84] Ibid.

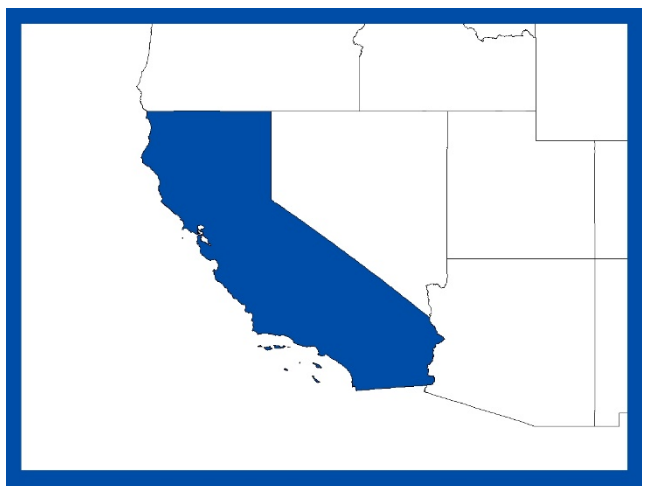
CALIFORNIA

Executive Summary

California, with a long history of oil and gas exploration and several large oil and gas fields, offers significant storage capacity for CO_2. California is one of the few states that recognizes CO_2 as a harmful pollutant, and opportunities for carbon credits through the Low Carbon Fuel Standard offer incentives for CCUS in the state. A Class VI permit application in the state is under review by EPA Region 9.

Background

California, the third largest state geographically, extends 100,206,720 acres.[1] The federal government owns 45,493,133 acres or 45.4% of this land.[2] California, the third largest state geographically, extends 100,206,720 acres.[3] The federal government owns 45,493,133 acres or 45.4% of this land.[4] Federal land ownership is largely dispersed throughout the southwestern portion of the state. According to the Legislative Analysts' Office 75 million acres of state land are classified as wildlands and 24 million are classified as agricultural land.[5] The remaining one million acres of the state is classified as urban or otherwise developed. Ownership of California's wildlands is divided among federal (60%), state (37%), and private entities (3%), with local governments owning less than one-half of 1 percent of wildlands in the state.[6]



There are approximately 110 federally recognized Native American tribes in the state of California, including several tribes with lands that cross state boundaries.[7] It is currently unclear how much tribal land qualifies as a legally recognized reservation set aside for the use by Native Americans, and how much land is held in a trust by the federal government.

California currently hosts the largest court system in the nation, which operates under common law. The state has 58 trial courts, with one court per county.[8] These courts currently host 1,754 judges and hear both civil and criminal cases. Appeals to trial court decisions reside with the 6 Courts of Appeal, consisting of 106 justices. The highest court in the state, the state Supreme Court, consists of 1 chief justice and 6 associate justices. The Supreme Court has the discretion to review Courts of Appeal decisions and resolves conflicts. California also hosts its own tribal justice system, and there

[1] Congressional Research Service. Federal Land Ownership: Overview and Data. R42346.

[2] Ibid.

[3] Congressional Research Service. Federal Land Ownership: Overview and Data. R42346.

[4] Ibid.

[5] Legislative Analyst's Office. California's Land Conservation Efforts: The Role of State Conservancies. Available at: https://lao.ca.gov/2001/conservancies/010501_conservancies.html.

[6] Ibid.

[7] California Tribal Court-State Court Forum. Frequently Asked Questions: Indian Tribes and Tribal Communities in California. Available at: https://www.courts.ca.gov.

[8] California Courts. About California Courts. Available at https://www.courts.ca.gov.

are currently 22 tribal courts located in the state.[9] There does not appear to be a special court system for water or mineral rights issues.

CCUS-related activities in California are overseen by the California Geologic Energy Management Division (CalGEM), formerly known as the Division of Oil, Gas, and Geothermal Resources (DOGGR). CalGEM is tasked with ensuring the safe development and recovery of energy resources. Activities that fall under their regulatory jurisdiction include drilling, operation, and permanent closure of oil, gas, and geothermal wells.[10]

CCUS Activities in the State

Oil and gas exploration and production in California began in the late 1800's. According to CalGEM, total oil production for 2019, the most recent year with aggregated data, was 156.4 million barrels, and total gas production in 2019 was 148.2 bcf (billion cubic feet).[11] Annual oil production has averaged about 209.4 million barrels over the last 20 years.[12] California was the seventh highest oil producing state in 2019.[13]

CalGEM maintains data on over 449 oil fields in the state.[14] The most productive crude oil and natural gas fields are found in the San Joaquin Valley and Los Angeles Basin.[15] The highest producing fields for associated and non-associated gas fields were the Elk Hills oil field and the Rio Vista gas fields respectively. The highest producing field for oil was the Belridge South field[16] and the largest quantity of active oil wells are located in Kern County, with about 30,814 wells, followed by Los Angeles County (with 4,445 active wells), and Ventura County (1,871 active wells). CalGEM has jurisdiction over approximately 101,300 active or idle production wells; as of July 30, 2021, there are 37,871 producing oil and gas wells in California.[17] There are additional offshore oil extraction operations in California within Los Angeles, Santa Barbara, and Orange counties.[18]

California has Class II UIC program primacy under Section 1425 of the SDWA, granted on March 14, 1983 to DOGGR.[19] There are nearly 37,000 injection wells in California, including 1,698 Class II wastewater disposal wells and 34,990 EOR wells.[20] The primary techniques utilized in California for EOR are waterflooding, thermal recovery, and gas injection.[21] All other classes of injection wells are

[9] California Courts. Tribal Justice Systems. Available at https://www.courts.ca.gov.
[10] CalGEM. Oil and Gas. Available at: https://www.conservation.ca.gov/.
[11] CalGEM. 2019 Annual Report of the State Oil and Gas Supervisor. Available at: https://www.conservation.ca.gov/.
[12] US Energy Information Association. California Field Production Of Crude Oil. Available at: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCA1&f=M.
[13] CalGEM. 2019 Annual Report of the State Oil and Gas Supervisor. Available at: https://www.conservation.ca.gov/.
[14] CalGEM. 2021 California Oil and Gas Wells. Available at: https://www.conservation.ca.gov/
[15] California Energy Commission. Petroleum Watch November 2020.
[16] CalGEM. 2019 Annual Report of the State Oil and Gas Supervisor. Available at: https://www.conservation.ca.gov/
[17] CalGEM. Oil and Gas. Available at: https://www.conservation.ca.gov/.
[18] California Energy Commission. Petroleum Watch November 2020. Available at: https://www.energy.ca.gov/
[19] EPA. Primacy Enforcement Authority – Underground Injection Control. Available at: https://www.epa.gov
[20] EPA. Underground Injection Control Well Inventory. Available at: www.epa.gov.
[21] California Energy Commission. Petroleum Watch November 2020. Available at: https://www.energy.ca.gov/

regulated by the EPA, although Regional Water Quality Control Boards can prescribe discharge requirements.[22, 23]

Currently, there is a lack of information regarding CO_2 pipeline infrastructure in the state, however, notional pipeline locations have been proposed based on known CO_2 emission sources and potential geologic storage locations. [24]

In 2019, CO_2 emissions for California totaled 418.2 million metric tons of CO_2. The transportation sector was the source of the most emissions, totaling 166.1 million metric tons, followed by industrial (88.2 MMT), electric (58.8 MMT), commercial and residential (43.8 MMT), agriculture (31.8 MMT), and recycling and waste (8.9 MMT).[25]

California's capacity to store CO_2 has been estimated to be between 33.89 and 423.70 billion metric tons. Saline formations account for the bulk of this amount, with an estimated capacity between 30.33 and 417.70 billion metric tons, followed by oil and natural gas reservoirs (3.56 to 6.63 billion metric tons).[26]

Much of the current research into CCUS has been in coordination with the West Coast Regional Carbon Sequestration Partnership (WESTCARB), which, under the leadership of the California Energy Commission and co-funded by DOE, identified and assessed regional opportunities for keeping CO_2 out of the atmosphere.[27] WESTCARB's research spanned the full range of potential geologic sinks in California, but focused on injection into saline formations. [28]

There is considerable interest in obtaining permits for geologic sequestration in California and as such, there is a pending Class VI permit application currently being reviewed by EPA Region 9.[29] It is anticipated that a bioenergy with carbon capture and sequestration (BECCS) project in Mendota, California will be one of the first Class VI projects to be permitted in California.[30] More than 99 percent of the carbon from the BECCS process is expected to be captured for permanent storage in a nearby deep saline formation. The plant is expected to remove about 300,000 tons of CO_2 annually.[31]

Classification of CO_2: Pollutant

California is one of the few states that directly recognizes CO_2 as a harmful pollutant. In 2006, the state passed the Global Warming Solutions Act of 2006 (AB 32) requiring the reduction of greenhouse

---

[22] BLR. California Underground Injection Wells. Available at: https://www.blr.com/.

[23] California Environmental Protection Agency. Dry Wells: Uses, Regulations, and Guidelines in California and Elsewhere. Available at: https://www.waterboards.ca.gov/.

[24] Energy Futures Initiative and Stanford University. An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions. Available at: https://sccs.stanford.edu/2020-ccs-report-launch.

[25] California Air Resources Board. California Greenhouse Gas Emission Inventory – 2021 Edition. Data available at: https://ww3.arb.ca.gov/cc/inventory/data/data.htm.

[26] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[27] WESTCARB. Home Page. Available at: https://www.westcarb.org/.

[28] WESTCARB. Characterization of Sites with High CCS Potential. Available at: https://www.westcarb.org/.

[29] EPA. Class VI Wells Permitted by EPA. Available at: https://www.epa.gov/uic/class-vi-wells-permitted-epa.

[30] Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage. in California: Opportunities, Challenges, and Solutions." October 2020. Available at: https://sccs.stanford.edu/2020-ccs-report-launch.

[31] Schlumberger, Chevron, Microsoft plan BECCS project in California. Schlumberger New Energy. March 4, 2021.

gas emissions, including carbon dioxide,[32] to 1990 emissions levels by 2020.[33] In doing so, California became the first state to place caps on carbon dioxide and other greenhouse gases. The statute also authorized the collection of a fee from sources of greenhouse gases.[34] In 2016, the state tacked on an additional statute that requires statewide greenhouse gas emissions to be reduced to 40% below the 1990 level by December of 2030.[35] An Executive Order by Governor Brown in 2018 further established a statewide goal to achieve carbon neutrality[36] by 2025.[37]

A key element of California's strategy to reduce greenhouse gas emissions is through the existence of its CO_2 cap-and-trade provisions. This provision, also established by AB 32, sets a statewide limit on the roughly 450 entities responsible for 80% percent of California's greenhouse gas emissions, and establishes a price signal.[38] Emission allowances are distributed by a mix of free allocation and quarterly auctions, with one allowance equaling one metric ton of CO_2 equivalent emissions. Each year, fewer allowances are created and the annual cap declines.[39] This program is enforced and implemented by the California Air Resources Board (CARB). Of note is that any CO_2 that is ultimately geologically sequestered is not included in their compliance obligation (see "Environmental laws," below).

The state also authorized CARB to "identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions," which included carbon sequestration projects.[40] Through AB 32, CARB implemented the Low Carbon Fuel Standard to incorporate credits for carbon capture and storage implemented in the fuel refinement process in determining a fuel's carbon intensity. LCFS credits can be traded on the credit market under the CARB's CCS Protocol.[41]

In 2019, the California legislature introduced a bill implementing a 10% oil and natural gas severance tax, but was ultimately not passed.[42] Since 1990, at least seven severance tax bills have been proposed, but thus far the state has never imposed a tax on the extraction of fossil fuels.[43] California does impose a production tax, however, on each barrel of oil and 10,000 cubic feet of natural gas produced.[44] The assessment rate is established in June of each year, and is based on CalGEM's estimated budget for the ensuing fiscal year and the total amount of assessable oil and gas produced during the prior calendar year. Additionally, individual counties may choose to impose an ad valorem tax.

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2- EOR

CalGEM is the regulatory agency for all oil and gas production activity within the State. No tribal or local laws or regulations address these activities within the state.

---

[32] California Health and Safety Code, § 38505 (g).

[33] AB 32 Air Pollution: Greenhouse Gases: California Global Warming Solutions Act of 2006.

[34] AB 32, Part 7, 38597.

[35] SB 32 California Global Warming Solutions Act of 2006: Emissions Limit.

[36] "Carbon Neutrality," as defined by the CARB, meant that carbon dioxide generated by sources such as transportation, power plants, and industrial processes must be less than or equal to the amount of carbon dioxide that is stored, both in natural sinks and mechanical sequestration.

[37] California Executive Order B-55-18.

[38] California Air Resources Board. ARB Emissions Trading Program. Available at: https://ww2.arb.ca.gov/

[39] More information on cap and trade here: https://ww2.arb.ca.gov/sites/default/files/classic/cc/capandtrade/guidance/chapter1.pdf

[40] AB 32, Part 3 (f).

[41] Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020.

[42] SB 246 Oil and Gas Severance Tax.

[43] Natural Gas Intel. California (Again) Considering Oil, Gas Severance Tax. Available at: https://www.naturalgasintel.com/california-again-considering-oil-gas-severance-tax/

[44] Article 7, Division 3, of the Public Resources Code.

Pipeline Regulations

CalGEM's Pipelines and Facilities unit oversees surface equipment used for the preparation and transportation of oil and gas for sale to refineries or gas utilities.[45] CalGEM has jurisdiction over tanks, pumps, valves, compressors, safety systems, separators, manifolds, and pipelines associated with oil and gas production and injection operations.[46] The State of California would likely designate a common carrier as a CO_2 pipeline company who is gathering CO_2 from multiple sources and transporting it to a disposal site. Common carrier regulations would allow such corporations to exercise eminent domain, claiming private property for public use. Conversely, corporations transporting CO_2 from a single source to a storage site would likely not be considered a common carrier, necessitating multiple negotiations with private landowners or public agencies to gain right-of-way or easements. The term right-of-way (ROW) is nearly synonymous with the term easement. An easement is the right to use another's property for a specific purpose and a ROW is an easement that specifically grants the holder the right to travel over another's property.[47, 48]

Laws and Regulations for CO_2 Storage

California has not been granted Class VI program primacy by EPA; therefore any Class VI wells in California are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 9. California is currently contemplating preparing a primacy application for the state to administer the Class VI program through CalGEM.[49]

While any Class VI permit application would be submitted to and reviewed by EPA, the application would also likely be shared for review with the State Water Resources Control Board (SWRCB), one or more of California's Regional Water Boards, and CalGEM.[50]

Regulation of Oil and Gas Production

Approval for drilling operations occurs in a two-step process. First, oil and gas companies must gain approval from local authorities before drilling can take place. Once approval is secured, a company must apply to CalGEM for a permit before constructing or operating a new well or modifying an existing one.[51]

Each permit application is reviewed for adherence to health and safety rules, environmental rules under the California Environmental Quality Act, and other state laws and guidelines. The requirements for oil and gas producing wells are at 14 CCR § Sections 1722-1724.4, and are issued under the Authority of Section 3013 of the Public Resources Code. Production well operators must submit a notice of intention to drill, deepen, redrill, rework, or plug and abandon wells to the appropriate Division district office for approval.[52]

The drilling permit request form (Form OG106) requests information about the operator, the surface location of the well, the depth of the well, whether fresh water or USDWs are present, the formations through which the well is drilled, the presence of critical or environmentally sensitive areas,

---

[45] Ibid.

[46] CalGEM. Pipelines and Facilities. Available at: https://www.conservation.ca.gov/.

[47] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.

[48] P. Hall et al., "Negotiating Pipeline Easements." Ohio State University Extension.

[49] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.

[50] Ibid.

[51] CalGEM. Oil and Gas Permits. Available at: https://www.conservation.ca.gov/.

[52] 14 CCR § 1722.

and information about casing cement and plugs. Applicants must also file an indemnity or cash bond.[53] "Freshwater" is defined as water that contains 3,000 mg/L TDS or less.

Production well casing and cementing requirements are at 14 CCR § 1722.2, 1722.3, and 1722.4. Wells must be designed and cased to segregate fluids for the protection of all oil, gas, and fresh water zones. Casing depths must be based upon geological and engineering factors, including but not limited to the presence or absence of hydrocarbons, formation pressures, and fracture gradients.

Oil and gas operators must comply with the California Environmental Quality Act, which requires consultation with local governments for each project.

CCR Title 14, Division 2, Chapter 4, Section 1712 states that regulations for oil and gas production apply to wells statewide. Although there are regulations, pursuant to CCR Title 14, Division 2, Chapter 4, Section 1722, the State Supervisor of Oil and Gas may establish Field Rules for any oil and gas pool or zone in a field when sufficient geologic and engineering data are available from previous drilling operations. Individual field rules are on CalGEM's web site.[54] CalGEM established Field Rules for those fields where geologic and engineering information is available to accurately describe subsurface conditions. These Field Rules identify parameters such as downhole conditions and well construction information that oil and gas operators should consider when drilling and completing onshore oil and gas wells.[55]

A well-spacing plan requires parcels of land to be pooled either voluntarily by interested parties or forcefully by the State Supervisor of Oil and Gas in order to protect correlative rights. Any well-spacing plan is not considered final until all interested parties have come to a voluntary pooling agreement, or the State Supervisor of Oil and Gas has issued a mandatory pooling agreement in the absence of a voluntary agreement. [56]

The state oil and gas supervisor may force or compel unitization and redesign of pressure plans if the initiation and conduct of repressuring operations will not substantially reduce the maximum economic quantity of oil or gas ultimately recoverable from the unit area as a whole, and if the estimated cost of initiating and carrying out repressuring operations within the unit area as a whole, including both capital and operating costs, will not exceed the estimated value of the increased production resulting therefrom.[57]

Our research did not identify any California regulations specific to off-shore CO_2 storage.

Regulation of Injection Activities

CalGEM's UIC Program administers state regulations for the permitting, drilling, inspecting, testing, and sealing of Class II injection wells.[58] Regulations apply to both onshore and offshore injection wells.[59] Key elements of the UIC regulations include testing requirements designed to identify potential leaks, continuous well pressure monitoring, requirements to automatically cease injection when there is a risk to safety or the environment, and requirements to disclose chemical additives for injection wells close to water supply wells.

The Class II UIC Regulations are in the California Code of Regulations, Title 14, Division 2, Chapter 4, Sections 1724.5-1724.13. All onshore and offshore Class II wells require a permit, and permit applications must demonstrate to the Division's satisfaction that injected fluid will not migrate out of the

[53] 14 CCR § 1722.1.
[54] CalGEM. Geologic Energy Management Field Rules. Available at: https://www.conservation.ca.gov.
[55] Ibid.
[56] 14 CCR § 1721.8.
[57] California Statutes and Regulations for the Division of Oil, Gas, and Geothermal Resources. Section 3320.2.
[58] CalGEM. Underground Injection Control. Available at: https://www.conservation.ca.gov.
[59] CalGEM. Updated Underground Injection Control Regulations. Available at: https://www.conservation.ca.gov.

approved injection zone through another well, geologic structure, fault, fracture, fissure, hole in the casing, or other pathway, considering project duration, volume of fluid to be injected, and other relevant factors. Permit applications must include information on wells in the area of review, geologic data on the injection formation, plans for drilling and plugging the well, information about fluids to be injected, and a monitoring program.[60] Injection well operators must comply with the California Environmental Quality Act, which requires consultation with local governments for each project.

Environmental Laws

California's Global Warming Solutions Act tasks CARB with lowering GHG emissions and maintaining a statewide GHG limit. The passage of SB 1383 set a target for statewide reductions in methane from 40% below 2013 levels by 2030.[61] Additionally, according to the ARB, regulations are currently being developed to reduce "fugitive" methane emissions from the oil and gas production, processing, and storage sector.[62] The California Public Utilities Commission (CPUC) has also implemented rules to minimize methane leaks from natural gas transmission and distribution pipelines.[63]

Entities that capture, inject, or store CO_2 in the subsurface must report data on GHG to the U.S. EPA and to the CARB. Under Title 17 of the California Code of Regulations (CCR), carbon dioxide suppliers are regulated under California's cap-and-trade program, but any carbon dioxide supplied that is ultimately geologically sequestered is not included in their compliance obligation (e.g., carbon dioxide supplied for enhanced oil recovery). Lastly, under Title 20, CO_2 that is sequestered is not included in the CO_2 emissions compliance obligation for power plants.

Other permits that CCUS facilities in California may need to obtain include permits for discharges to waters of the State (through the state or regional water quality control boards), discharge of dredge or fill materials (with the U.S. Army Corps of Engineers), and permits for stream/river/lake alterations (with the Department of Fish and Wildlife). [64]

Under the Seismic Hazards Mapping Act of 1990, "cities and counties may withhold the development permits for a site within seismic hazard zones until appropriate site-specific geologic and/or geotechnical investigations have been carried out and measures to reduce potential damage have been incorporated into the development plans."[65] However, it appears that DOGGR/CalGEM's moratorium is specific to hydraulic fracturing operations.[66]

Industrial Siting Requirements

There are no siting requirements specific to CCUS projects. Although, as noted under "Regulation of CO_2 Injection," permit applications must describe the proposed injection/production well site and demonstrate that it is suitable for safe injection.

---

[60] 14 CCR § 1724.7.

[61] C.A. S.B. 1383

[62] Short-Lived Climate Pollutant Reduction Strategy, March 2017, *California Environmental Protection Agency Air Resources Board.*

[63] Ibid.

[64] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.

[65] Suncrest Dynamic Reactive Power Support Project. Draft Environmental Impact Report Ch.9. Geology, Soils, and Seismicity.

[66] Norton Rose Fulbright US LLP. Induced Earthquake Shake Up Regulatory and Litigation Landscape.

Eminent Domain

California authority for eminent domain is found in Title 7 of the state's Code of Civil Procedure. Private property can only be taken by eminent domain when there is a "public use,"[67] which the state defines as property that is either already in use for a public purpose, or property set aside for a specific public purpose with the intention of using it.[68] It is further specified that an "electric, gas, or water public utility property" means property appropriated to a public use by a public utility."[69] To qualify as a "public use" project, the public interest and necessity must require the project, and the property sought to be acquired be necessary for the project.[70] It is up to the legislative body having jurisdiction over the proposed project to determine whether the public interest is served and whether the property is necessary.[71] State law has, however, already statutorily declared that pipeline corporations and gas corporations may condemn any property necessary for its construction and maintenance.[72]

In addition, the owner of the property must be paid "just compensation," although the property owner is not required to accept the condemning agency's offer and can assert a higher property value once the eminent domain action is filed in court. However, the condemner in question still must make "every reasonable effort" to acquire the property through negotiation.[73] These negotiations are based on an appraisal.[74]

The condemnation process begins with a request by the condemner for a "Resolution of Necessity" by the legislative body having jurisdiction over the proposed project, proving that the land in question is necessary to serve the public interest. This resolution must be adopted at a public hearing. If adopted, the condemner can file to obtain eminent domain in the respective court. The landowner must then be notified of the condemner's intentions and the price that the condemner is willing to pay. The landowner can accept the offer, and the sale will be finalized in 30-60 days. Alternatively, the landowner can reject the proposal by claiming that it will have no public benefit or that the proposed price does not represent the fair value of the property.[75] Additionally, California has declared the right of eminent domain to exist "to all frontages on the navigable waters" of the state.[76]

California does not seem to have any special eminent domain provisions specifically addressing CO_2 pipelines or underground storage. As mentioned previously, California would likely designate a CO_2 pipeline company who is gathering CO_2 from multiple sources and transporting it to a disposal site to be a common carrier. Common carrier regulations would allow such corporations to exercise eminent domain.[77]

---

[67] Cal Code Civ Proc § 1240.010.
[68] Cal Code Civ Proc 1235.180.
[69] Public utility, as defined in 216, includes every common carrier where the service is performed for, or the commodity is delivered to, the public or any portion thereof. This definition explicitly lists pipeline and gas corporations as a type of public utility.
[70] Cal Code Civ Proc, § 1240.030.
[71] Cal Code Civ 1240.010.
[72] Cal Public Utilities Code, §613-615.
[73] CA Govt Code § 7267.1 (a).
[74] CA Govt Code § 7267.1 (b).
[75] Cal Code Civ Proc 1235.193.
[76] California Constitution, Article x, Sec. 1.
[77] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

California defines "mineral rights" as interest in minerals created by grant or reservation, regardless of character, composition, or form.[78] As such, mineral rights can be held as "fee, lesser interest, mineral, royalty, or leasehold, absolute or fractional, corporeal or incorporeal, and includes express or implied appurtenant surface rights."[79] Landowners who lease their land can grant a lesser property interest, such as for extraction of minerals, oil, or gas for a certain amount of years.[80] In California, this lease entitles the leaseholder to reasonable access to enter the land as necessary to develop and remove the corpus of the granted resources.[81] This right of access can be inferred, even when the grant does not expressly contain it.[82] However, any lessee of an expired or abandoned mineral right lease must execute and record a quitclaim deed of all interest in and to the mineral rights covered by the lease within 30 days of the lessor's request.[83]

California courts must follow state law when interpreting disputed contracts. All contracts must be interpreted so as to ascertain the mutual intentions of the parties listed in the contract, from the time of its creation.[84] In doing so, the courts must look to the written language of the contract and whether it is "clear and explicit."[85] Generally, the terms themselves should be interpreted according to their plain, everyday usage, rather than their strict legal meaning. However, if a special meaning is given to certain terms by usage, then the strict legal meaning will be considered instead.[86] Similarly, technical words from people in the same industry must be interpreted the way that the industry would typically use the term.[87]

When the language in a contract is either ambiguous or uncertain, California courts must interpret it in the way the promisor believed that the promisee understood it at the time the contract was made.[88] Words that are considered to be "wholly inconsistent" with the parties' main intentions will be thrown out. If any uncertainties remain, courts must interpret contract language predominantly against the drafting party who "caused the uncertainty to exist" in the first place.[89] In other words, the contract should be interrupted in a way that benefits the side that did not write the agreement. It appears that the term "mineral" is not defined in the context of oil and gas production activities.

---

[78] California Civil Code § 883.110.
[79] Ibid.
[80] Graciosa Oil Co. v. Santa Barbara Cty., 155 Cal. 140, 144 (1909).
[81] Richfield Oil Co. of Cal. v. Hercules Gasoline Co., 112 Cal. App. 431, 434 (1931).
[82] Francis v. W. Va. Oil Co., 174 Cal. 168, 170-71 (1917).
[83] California Civil Code § 883.140 (b).
[84] California Civil Code § 1636.
[85] California Civil Code § 1638-1639.
[86] California Civil Code § 1644.
[87] California Civil Code § 1645.
[88] California Civil Code § 1649.
[89] California Civil Code § 1654.

Split Estates

California does not appear to possess a split estate statute or a surface protection act. However, the right to split one's mineral rights from the surface was adopted in *Graciosa Oil Co. v. Santa Barbara City (10(0))*, in which the Court declared that "[T]he estate of the owner of the overlying land and of the owner of the subterranean stratum will be as distinct and separate as is the ownership of respective owners of two adjoining tracts of land."[90] Here, each estate becomes unique and separate from the other. Additionally, mineral estates are viewed as dominant when separated from surface estates. In the case of *Cassinos v. Union Oil Co. of California*, the court ruled that "the right of the surface owner is subordinate to an oil and gas lessee, and he may not affect the mineral estate owner's rights so as to prevent his enjoyment thereof or unreasonably interfere therewith."[91] In addition, injunctive relief is available to prevent interference from the surface owner, although the mineral owner/lessee must first provide the surface owner with written notice of their intent to enter the property before seeking it.[92, 93]

State law dictates that the taking of minerals is considered a servitude upon land that may be attached to other land and therefore considered an easement.[94] The land to which an easement is attached is called the dominant tenement; the land upon which a burden or servitude is laid is called the servient tenement.[95]

Statutorily, California does contain a dormant mineral rights provision that would terminate title to minerals rights and reconvey it to the owner of the real property. Under this act, any property owner subject to a mineral right can terminate the mineral right pursuant to this article if the mineral right has been "dormant"[96] for a period of 20 years.[97] However, mineral rights owners can also record a "notice of intent" to preserve the mineral right at any time before the 20 year period.[98] Additionally, California courts permit mineral rights owners to record a late notice of their intent to preserve the mineral rights so long as they pay the surface owner their attributable litigation expenses.[99]

---

[90] Graciosa Oil Co. v. Santa Barbara Cty., 155 Cal. 140, 144 (1909).

[91] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.

[92] Caflahan v, Martin, 3 Cal. 2d 110, (Cal. 1935).

[93] Flowers, Celia C. and Reyes, Melanie S. (2015). We Have to Drill This Well Somewhere - A Survey of Surface Issues Across the Nation. *IRWA Pipeline Committee Meeting.* Accessible at https://flowersdavis.com/wp-content/uploads/2017/01/2015-09_We-have-to-Drill-this-Well-Somewhere-by-Celia-C.-Flowers.pdf.

[94] California Civil Code § 801.

[95] California Civil Code § 803.

[96] To qualify as "dormant" under California statute, there must be no production, exploration, drilling, mining, or development of minerals, whether on or below the surface of the real property or on other property, whether or not unitized or pooled with the real property. There must also be no separate property tax assessment of the mineral right or, if made, no taxes paid on the assessment. Furthermore, there must be no recorded instrument creating, reserving, transferring, or otherwise evidencing the mineral right. *California Civil Code § 883.220 (a-c).*

[97] California Civil Code § 883.210 - 883.270.

[98] California Civil Code § 883.230.

[99] Per California Civil Code *§* 883.250, "litigation expenses" means recoverable costs and expenses reasonably and necessarily incurred in preparation for the action, including a reasonable attorney's fee.

Pore Space Ownership

The issue of pore space ownership in California was almost addressed with the Carbon Capture and Storage Act of 2013 (SB 34). The bill died, however, when its sponsor, state Senator Ronald Calderon, took an indefinite leave of absence.

Property law discussing the difference between mineral rights and pore space rights is ambiguous in California. Ultimately, the party interested in acquiring pore space rights may need to negotiate with both surface and mineral estate owners to obtain surrounding subsurface pore space. In California, land is defined as "[…] the material of the earth, whatever may be the ingredients of which it is composed, whether soil, rock, or other substance, and includes free or occupied space for an indefinite distance upwards as well as downwards, subject to limitations upon the use of airspace imposed, and rights in the use of airspace granted, by law."[100] The owner of land "has the right to the surface and to everything permanently situated beneath or above it."[101] This implies that the surface owner has ownership concerning pore space rights, but in the case of a severed mineral estate beneath the surface estate, the mineral estate owner may have precedence. The case of Cassinos v. Union Oil Co. of California discusses this estate precedent in the previous section and is further discussed here. This case involved a mineral owner who sued an operator for injecting wastewater under a property after receiving permission from the surface owner. In their ruling, the courts stated that, "even if [the surface owner] did own the pore space and could authorize injection …," the mineral owner's trespass claim was still valid because the operator also caused an injury to the mineral estate."[102] According to natural resources attorney Stefanie Burt, California court has therefore avoided analysis of the issue of pore space ownership; however, "given the assumption in Cassinos, another California court to consider the issue will likely agree with the prevailing rule that the surface owner owns the pore space."[103] The ambiguity surrounding pore space ownership in the context of CCUS projects presents implications for property trespass, especially when fluid migration is considered.[104]

Water Rights

California's system is unique in that it incorporates riparian rights, appropriative water rights, reserved rights,[105] and pueblo rights.[106] Article X, Section 2 of the California Constitution requires that the use of water should be both "reasonable and beneficial."[107] However, failure to use claimed water for a period of 5 years will result in the unused water being reverted back to the public and regarded as "unappropriated public water."[108]"Domestic purposes" is the highest priority for water use in the state, followed by irrigation.[109]All water flowing in any natural channel is declared a public water of the state and subject to the doctrine of prior appropriation, unless it has already been claimed for beneficial purposes or to riparian lands.[110]

---

[100] California Civil Code § 659.
[101] California Civil Code § 829.
[102] Ibid.
[103] Stefanie L. Burt. Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions.
[104] George Peridas, Permitting Carbon Capture & Storage Projects in California, February, 2021, Lawrence Livermore National Laboratory, LLNL-TR-817425.
[105] "Reserved rights" is water set aside by the federal government when it reserves land for the public domain.
[106] "Pueblo rights" are *a* municipal right based on Spanish and Mexican law.
[107] Cal. Const, Article X § 2.
[108] California Water Code, §1241.
[109] Cal. Water Code, 101.
[110] Cal. Water Code, 1201.

Riparian rights are considered to be superior in priority to appropriative rights. According to the California State Water Resources Control Board, riparian right holders generally hold equal priority to one another, even in times of shortage.[111] However, they only attach to the "natural flow" in the watercourse. They also do not require a permit or a license, unlike with appropriative water rights.[112] In addition, riparian rights remain with the property during ownership transfers, although severed parcels from an adjacent water source "typically lose their right to the water."[113]

For appropriative rights holders, priority of right is established by the date that the permit application was filed with the State Water Resources Council Board.[114] In the event of a shortage, the most recent appropriative rights holder must be the first to discontinue use. Unlike with riparian rights, appropriative rights holders require a permit or license from the State Water Resources Control Board for California's surface water. The appropriation itself must be for some "useful or beneficial" purpose.[115] The right ceases once the appropriator stops using the water for the original intended purpose.[116]

According to the California Water Board, California does not have a permit process for regulation of ground water use.[117] However, groundwater use is subject to regulation in several basins "in accordance with court decrees for ground water rights."[118] As with surface water, groundwater in California is also subject to the provision of "reasonable use."[119]

California is one of five states that also uses the correlative rights doctrine, which builds upon the reasonable use rule by not prohibiting off-site uses and by imposing a proportionality rule.[120] Thus landowners must limit their use of groundwater so as to not interfere with the use of the water by others overlying the aquifer.

For purposes of regulating oil and gas production, "freshwater" is defined as water containing less than 3,000 mg/L TDS for the purposes of well construction.[121] California's Class II UIC regulations define a USDW as water containing no more than 10,000 mg/L TDS,[122] consistent with the federal definition of a USDW.

Lithium Ownership and Extraction

California is recognized as a potential global leader in lithium production, with the ability to meet at least one third of the current global demand for lithium. The Salton Sea region is considered to host the greatest potential for lithium extraction from brine waters in California.[123] Lithium mines are also present in several California counties, including: Imperial, Inyo, Plumas, Riverside, Sacramento, San Bernardino,

[111] State Water Resources Control Board. The Water Rights Process. Available at: https://www.waterboards.ca.gov/.
[112] Ibid.
[113] Ibid.
[114] Cal. Water Code, 1450.
[115] Cal. Water Code, 1240.
[116] Ibid.
[117] State Water Resources Control Board. The Water Rights Process. Available at: https://www.waterboards.ca.gov/.
[118] Ibid.
[119] 141 Cal. 116, L. A. 967, Katz v. Walkinshaw.
[120] KATZ v. WALKINSHAW, 141 Cal. 116 (Cal. 1903).
[121] 14 CCR § 1720.1.
[122] 14 CCR § 1720.1.
[123] AB 1657.

and San Diego.[124] The Blue-Ribbon Commission on Lithium Extraction (Lithium Valley Commission) is a part of the California Energy Commission and is tasked with the review, investigation, and analysis of opportunities and benefits for lithium recovery and use in California. This report will contain elements including, but not limited to, economic and environmental impacts, tax credits, marketing opportunities, and proposed regulations for lithium extraction and production. The investigation will be performed in accordance with EPA and DOE and the final report summarizing this information is due to the state legislature in or before October 2022.[125] Our research did not identify current regulation regarding lithium production in California.

---

[124] Diggings. Lithium Mines in California. Available at: https://thediggings.com/commodities/lithium/usa/california.
[125] Ibid.

INDIANA

Executive Summary

Coal beds and saline formations throughout Indiana are attractive targets for CCUS because of their distribution relative to CO_2 sources and their favorable geologic characteristics. Indiana's consideration of the use of CO_2 transmission pipelines and the underground storage of CO_2 as a public use for purposes of Eminent Domain, and financial incentives for utilities employing CCUS, increase the attractiveness of the state for CCUS. The Wabash Valley Resources project will likely be permitted soon for Class VI injection.

Background

Of Indiana's 23,158,400 acres, 384,726 acres are owned by the federal government.[1] There are two tribes that hold land in Indiana – the Federally recognized Pokagon Band of Potawatomi and non-federally recognized Miami Tribe of Oklahoma.[2] The State of Indiana does not recognize any organization as a "State Recognized Tribe." The Pokagon land consists of 155 acres of trust land in the city of South Bend.[3] No information is available on acreage of land for the Miami Tribe, but the tribe has lands in Fort Wayne, Indiana.

Indiana's court system consists of two levels: the trial court and the appellate court. The Supreme Court of Indiana, along with the Indiana Tax Court and the Court of Appeals are included as appellate-level tribunals.[4] The trial courts are further separated into three classes: circuit courts, superior courts, and local, city or town tribunals. Indiana has 92 counties but 91 circuit courts, with 90 having their own circuit courts and the divisions of Ohio and Dearborn sharing 1 circuit. The court of appeals has 15 judges drawn from 1 of 5 Appeals Court districts, and only hears cases that have already been heard by the trial courts.[5] The Indiana Supreme Court is the highest appellate court and consists of 1 chief justice and 4 associate justices.[6]

All oil and gas operations (including oversight of injection and production wells) in Indiana are regulated by the Indiana Department of Natural Resources (INDR), Division of Oil and Gas. Pipelines are regulated by the Natural Resources Commission (NRC), comprised of the commissioners of the Indiana Department of Environmental Management and the Indiana Department of Transportation (IDOT), the director of The Department of Natural Resources (INDR) and other related local officials.[7] No tribal or local laws or regulations address CCUS-related activities within the state.

---

[1] Congressional Research Service. Federal Land Ownership: Overview and Data. Available at: https://crsreports.congress.gov/.

[2] Are there any Native American tribes in Indiana? Available at: https://faqs.in.gov/hc/en-us.

[3] Pokagon Band of Potawatomi. Indiana Land Restoration. Available at: https://www.pokagonband-nsn.gov/government/indiana-land-restoration.

[4] Indiana Court System. Indiana Arrests. Available at: https://www.indianaarrests.org/indiana-court-system.html.

[5] Courts: Appeals: Judges of the Court of Appeals. Available at: in.gov.

[6] Courts: Supreme Court: About the Court. Available at: in.gov.

[7] IN Code § 14-10-1-1.

CCUS Activities in the State

Indiana's oil and natural gas production industry began in 1886 with the discovery of the now abandoned Trenton gas field in east-central Indiana. However, significant oil production began around 1940 in the oil fields of southwestern Indiana, within the Illinois Basin. Indiana's crude oil production increased with the use of advanced drilling technology; however, in 2017, the state's oil production dropped to its lowest in a decade and accounted for less than 0.1 percent of U.S. total oil production.[8] Indiana does not publish production information, and records of historical oil and gas production volumes for fields and individual wells in Indiana are quite variable, complicating production estimates.[9] Indiana does not have significant natural gas reserves.[10]

About 70% of Indiana's CO_2 emissions from stationary sources are generated at coal-fired power plants. Additional sources of CO_2 in the state include ethanol facilities, cement kilns, and petroleum refineries.[11] Coal beds and saline formations are particularly attractive in Indiana because of the distribution of these potential storage reservoirs relative to CO_2 sources and their favorable geologic characteristics.[12] Indiana's capacity to store CO_2 has been estimated to be between 38.25 and 128.76 billion metric tons. Saline formations account for the bulk of this amount, with an estimated capacity between 38.14 and 128.52 billion metric tons, followed by coal beds (0.09 - 0.17 billion metric tons) and oil and natural gas reservoirs (0.02 to 0.07 billion metric tons).[13]

One of the primary basins targeted for CO_2 storage is the Illinois Basin, which covers most of Illinois, southwestern Indiana, and western Kentucky.[14] In particular, the Mount Simon Sandstone has been identified as a formation with high storage capacity.[15] Within Indiana, the Mount Simon Sandstone ranges in thickness from less than 400 feet in eastern Indiana to around 2,500 feet at its thickest section near northwestern Indiana.[16] Other basins of interest include the Michigan Basin which encompasses part of northern Indiana.

According to the Global Carbon Capture and Sequestration Institute, there are two major CCUS projects proposed or completed in Indiana. In 2012, the Midwest Geological Sequestration Consortium (MGSC) conducted a small-scale carbon dioxide injection test within the Clore sandstone formation in Barrett, Indiana to gauge the feasibility of large-scale CO_2 storage in mature Illinois Basin oil fields using the EOR technique of miscible liquid CO_2 flooding. As of 2021, Wabash Valley Resources is currently planning to develop a hydrogen plant with near-zero CO_2 emissions using a repurposed integrated gasification combined cycle plant in Harrison, Indiana.[17]

---

[8] DOE. Indiana Natural Gas Flaring and Venting Regulations. Available at: https://www.energy.gov/.

[9] Illinois Geological Survey. Availability of Values for Historical Petroleum Production in Indiana. Available at: https://igws.indiana.edu/.

[10] US Energy Information Administration. Indiana State Energy Profile. Available at: https://www.eia.gov/state/analysis.php?sid=IN.

[11] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.

[12] Indiana Geological and Water Survey. Carbon Dioxide Storage Capacity in Indiana. Available at: https://igws.indiana.edu/.

[13] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[14] Ibid.

[15] Demonstrating the suitability of the Mt. Simon, the Decatur Project in the Illinois portion of the Illinois Basin has been permitted as a Class VI project since 2015.

[16] Indiana Geological and Water Survey. Carbon Dioxide Storage Capacity in Indiana. Available at: https://igws.indiana.edu/.

[17] Global CCS Institute. Facilities — CO_2RE. Available at: https://www.globalccsinstitute.com/co2re/.

Previous attempts to establish CO_2 pipeline infrastructure have stalled due to issues securing eminent domain as well as public opposition. For example, Indiana Gasification, a subsidiary of Leucadia Corporation, planned to build a pipeline from southern Illinois to their EOR operations near the Jackson Dome in Mississippi. The proposed pipeline was initially intended to carry CO_2 from multiple sources, one of which was the coal gasification plant located in Rockport, Indiana. After efforts to secure eminent domain failed, the Indiana Department of Environmental Management rescinded the air-quality permit issued for the project at Leucadia's request.

Classification of CO_2: Commodity and Pollutant

Indiana holds active statutes regarding the taxation of secondary recovery methods, but not enhanced recovery,[18] which could include CO_2 flooding operations. The state does host a severance tax for the production of natural gas, but the definition of gas in this usage is reserved for petroleum.[19]

Indiana has not specifically referenced CO_2 as a pollutant but likely includes it in its definition of an air contaminant. The state cites gas as an "air contaminant" in its air pollution control laws[20] and lists "all types of business, commercial, and industrial plants" as a type of "air contaminant source." They do not seem to define "gas" in these regulations, however. Indiana has specifically regulated the concentration of CO_2 in the air - but only for indoor areas.

The "Utility Generation and Clean Coal Technology" subsection of the state's Utilities and Transportation Code subsection provides financial incentives for utilities building "new energy" generators, including coal fired power plants utilizing CCUS technology.[21]

In 2021, state lawmakers introduced a bipartisan bill aimed at carbon sequestration. SB 373 provided for the development of a carbon market in Indiana by encouraging Indiana companies to buy voluntary carbon offsets. It also provided for funding a pilot Class VI geologic sequestration project in the state.[22] The bill passed both the Senate and the House, but the House amendments to the engrossed bill were dissented by the Senate, and it was adjourned sine die before it progressed any further.[23] Additionally, as described under "Eminent Domain" below, Indiana considers the use of CO_2 transmission pipelines and the underground storage of CO_2 as a public use and a service in the public interest to the people of Indiana.

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

The requirements for production and Class II injection wells are in Article 29 of the Indiana Administrative Code. The DNR in Indiana has primary enforcement authority for Class II wells. All other injection wells, including Class VI GS wells, are regulated by EPA Region 5. Regulatory activities under the DNR's jurisdiction include drilling, casing, operating, plugging, and abandonment.

Pipeline Regulations

According to Indiana statute, pipelines are regulated by the NRC and Indiana Department of Natural Resources (INDR) Division of Oil and Gas. Specifically, "flow lines" include all lines within the boundaries of a lease or production unit used for transporting any mixture of crude oil, coal bed methane,

[18] IC 6-1.1-4-12.6.
[19] IC 6-8-1-5.
[20] IC 13-11-2-3.
[21] Ind. Code § 8-1-8.8-12.
[22] Senate Bill 373: Carbon Credit Market, Carbon Sequestration, and federal mandates.
[23] Ibid.

natural gas, petroleum products, or produced water to a Class II well or underground storage well.[24] Our research did not identify any requirements related to CO_2 pipelines.

Laws and Regulations for CO_2 Storage

Senate Bill (SB) 442 was introduced and passed as Public Law 291 in 2019 and pertains to the underground storage of CO_2. Under this law, the storage of CO_2 is considered a public use and a benefit to the people of Indiana. The Wabash Valley Resources project was authorized as a CCUS pilot project for capturing and injecting CO_2 at an ammonia production facility in accordance with the federal Class VI rule. The law provides the power of eminent domain to the pilot project operator if an agreement cannot be reached between the operator and the owner of subsurface or surface property that is pertinent to CCUS activities. This includes underground strata located under property; or ownership of surface areas of the property for purposes of monitoring facilities required by EPA. If the operator acquires property through eminent domain, the acquisition must abide by the law on eminent domain for gas storage. According to this law, the condemner must acquire the right to store gas in at least 60% of the stratum without the use of condemnation. Upon approval from the director of the DNR and the state budget committee, Indiana may obtain ownership of both the stored CO_2 and the strata in which it is stored 12 years after injection begins at the pilot project or if injection ceases in less than 12 years.[25, 26] Although in the pilot stage, the Wabash Valley project will likely form the basis for future CCUS activity and associated regulation in Indiana. Further discussion regarding eminent domain and CO_2 transportation and storage can be found under "Eminent Domain" below.

Indiana has not been granted Class VI program primacy by EPA; therefore any Class VI wells in Indiana are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 5.

Indiana does have legislation providing financial incentives for utilities building new energy generators, including coal plants employing CCUS.[27]

Regulation of Oil and Gas Production

All oil and gas operations in Indiana are regulated by the DNR.[28] All permit applications for drilling, deepening, operating, or converting a well for oil and gas production purposes must include information pertaining to the well's site.[29] The requirements for permit applications are at 312 IAC 29-4-2. An applicant must provide information on the location of the well, a financial bond, and a demonstration of ownership of mineral interest.[30] There are no requirements for applicants to provide specific information about the well or subsurface formations, although the permit application form on the DNR's web page requests information about the depth of the well, proposed injection pressures, casing and cementing information, and the name of the deepest formation drilled.[31] Specifications for well casing strings and cement are at 312 IAC 29-20-3 through 312 IAC 29-20-8. Production well permit applications are subject to public hearings.[32]

[24] 312 IAC 29-2-56 "Flow Line Defined."
[25] SB 442.
[26] IN Code § 32-24-5-2.
[27] IC 8-1-8.8-12.
[28] IC 14-37-3-7.
[29] 312 IAC 29-4-2 Permit Applications.
[30] 312 IAC 29-4-3.
[31] Application for well permit. State form 21096. Available at https://www.in.gov/dnr/oil-and-gas/.
[32] 312 IAC 29-3-4.

Except in accordance with the requirements of 312 IAC 29-18, wells for oil and gas purposes cannot be drilled within a half-mile of underground gas or petroleum storage facility.[33] Applications to drill within the boundary of a city or town must be accompanied by a certified copy of the consent to drill from the city or towns legislative body.[34]

State regulations require that every lease of public lands contain a clause authorizing the unitization of the land with other lands for common development, exploration, and operation. The Commission may incorporate a unitization requirement in a lease of public lands.[35] Indiana does not mandate a minimum percentage ownership to unitize interests but the applicant must first make a good faith effort to lease all interest owners. If two or more interest owners are unable to reach an agreement to pool their interests, the interests would then be involuntarily included in the unit under IC 14-37-9-1 in order to prevent waste and the unnecessary drilling of additional wells.[36, 37]

Regulation of Injection Activities

Indiana received UIC program primacy for Class II injection wells under Section 1425 of the Safe Drinking Water Act on August 19, 1991.[38] All other wells, including Class VI wells, are overseen by EPA Region 5. Under 312 IAC 29-5 all operators seeking to convert an existing well or to drill and construct a Class II well, must submit a permit application to the DNR. Basic permit application requirements for all wells overseen by DNR are described under “Regulation of Oil and Gas Production” above, but Indiana has additional requirements for Class II wells, mandating that operators include information on wells in the area of review; a schematic diagram of the proposed Class II well that includes the depth, information in the injection and confining zone, and depth to the base of the USDW; and proposed operating data.[39]

Furthermore, Class II permit applicants must provide evidence that wells within the AoR of the Class II well are constructed or plugged with sufficient cement to prevent the injection fluid and fluid in the injection formation from contaminating a USDW. Evidence may include well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs, and plugging records.[40]

Operators seeking a permit for Class II injection must provide written notification to anyone with a surface or subsurface property interest within a quarter mile of the proposed Class II well. The notification must include the name and address of the applicant, the location of the proposed well, the lease name and well number of the proposed well, the geological name and depth intervals of the injection zones, the proposed maximum injection pressure, the proposed maximum rate of barrels each day, and a submission address. The notice also must clarify that anyone may submit written comment or request an informal hearing.[41]

---

[33] 312 IAC 29-4-5 Permitting of wells within one-half mile of a gas or petroleum storage reservoir.
[34] 312 IAC 29-4-6 Application requirements for a well within incorporated boundary of a city or town.
[35] IAC 17-1-13.
[36] IC 14-37-9-1
[37] Horizontal Well Development Pooling, Spacing, and Unitization: A Regulatory Toolbox for Key Policy, Regulatory, and Statutory Considerations. Available at https://iogcc.ok.gov/sites/g/files/gmc836/f/pstoolboxfinal.pdf.
[38] 56 FR 41072, Aug. 19, 1991, as amended at 62 FR 1834, Jan. 14, 1997.
[39] 312 IAC 29-5-1 Class II well applications.
[40] Ibid.
[41] 312 IAC 29-5-2 Notification to potentially affected parties.

Environmental Laws

Coal bed methane wells are regulated by the Indiana Interstate Mining Commission. Permit applications are required for their usage to assess the potential impact on USDWs and on commercially minable coal resources.[42] Permit applications require plans for stimulation and disclosure of the types and amounts of fluids and products used, as well as plans for horizontal drilling and plugging.[43] If ownership of the coal bed methane is separate from the ownership of the coal, Indiana statute forbids exercise of surface rights unless either the coal owner consents or the Department of Natural Recourses decides that doing so would not waste commercially minable mineral coal resources.[44]

Additionally, the Indiana Department of Environmental Management requires air permits or approval from the Office of Air Quality for stationary sources that emit greenhouse gases; which includes both carbon dioxide and methane.[45]

The oil and gas regulations do not address induced seismicity. The Indiana Geological Survey studied the potential for injection-induced seismicity[46] and results of this analysis show four earthquakes having high correlation and two having moderate correlation to injection activities, in an area in southwestern Indiana with a large amount of oil and gas development activity. The report includes recommendations for further research, but does not recommend regulatory approaches, and there do not appear to be any requirements for addressing seismicity in the production or injection well regulations.

Fresh water is defined at 312 IAC 29-2-60 "for purposes of identifying an underground source of drinking water [as]...water that contains no more than ten thousand (10,000) milligrams per liter of total dissolved solids." The oil and gas rules define a USDW as an aquifer that presently supplies fresh water to any user or contains a sufficient quantity of fresh water to supply a future user.[47] While this definition is not the same as the federal definition, it references the state's definition of fresh water, which is consistent with the 10,000 mg/L TDS content stipulated in the federal UIC rules.

Industrial Siting Requirements

Requirements for drilling units and well spacing for vertical oil wells are provided at 312 IAC 29-13-3. All wells must be located 330 feet from a lease line, property line, or subdivision that separates unconsolidated property interests and 660 feet from an oil or gas well producing from the same reservoir, although there are some exceptions to this rule. For example, wells that are deeper than 1,000 feet must be located on a drilling unit with at least 40 acres of surface area, or a quarter, quarter section of land according to public land survey. These wells must be 1,320 feet from a well for oil and gas capable of producing from the same unit.[48]

Requirements for drilling unit size are prescribed based on reservoir lithology. Drilling units targeting sandstone formations must be about 10 acres, or a quarter, quarter, quarter section, while drilling units on other reservoirs must be about 20 acres, or a half a quarter, quarter section.[49, 50]

---

42 IC 14-37-3-14.5.

43 Ibid.

44 IC 14-37-4-8.5.

45 IDEM. Regulated Pollutants. Available at: in.gov.

46 J. A. Rupp, A. L. Dufficy, and M.W. Hamburger. Preliminary Investigation of the Potential for Induced Seismicity in Indiana. Report of Progress 48. Indiana geological Survey. 2016.

47 312 IAC 29-2-131.

48 312 IAC 16-5-1 Well spacing.

49 312 IAC 16-5-2 Drilling units.

50 There are also exceptions for wells within the Trenton Limestone reservoir; however, limestone formations are unlikely to be targets for CCUS activities.

Eminent Domain

Article 24 in Title 32 of Indiana statutes outlines the Eminent Domain Act and its powers and procedures.[51] A condemner[52] may not take or damage property by the power of eminent domain unless it is for a public use.[53] Condemners for public utilities/corporations may take, acquire, condemn, and appropriate an estate in fee simple, as well as the title and interest, in an amount of land that they consider necessary for their "proper uses and purposes."[54] For rights-of-way, however, the condemner must take, acquire, condemn, and appropriate an easement.

In general, condemners may enter the land and survey the property to be condemned; however, public utilities[55] and pipeline companies must first either receive the landowners' signed consent or send notice by certified mail to the effected landowner at least 14 days before the proposed survey examination.[56] The condemner must also "make an effort" to purchase the right-of-way, easement, or other interest in the property. [57] To establish a purchase price for the property, the condemner must provide the owner with an appraisal or with "other evidence used to establish the proposed purchase price." [58] If the condemner and the owner do not agree on the damages sustained by the owner, the authority may file a complaint with the clerk of the circuit court of the county where the property is located; however, this cannot occur until at least 30 days after the offer was made to purchase the property.[59, 60] Pipeline or utility companies who submit a written acquisition offer and are rejected in writing by the owner have 6 years to file a complaint; failure of which leads to their inability to acquire property, or one similar, for another 2 years after the 6 year period expires.[61]

Indiana is unique in that it contains explicit eminent domain requirements for carbon dioxide pipeline transportation companies[62] and for the underground storage of carbon dioxide.[63, 64] Under article 39 of Title 14, the use of carbon dioxide transmission pipelines and the underground storage of carbon dioxide is declared a public use and a service in the public interest to the people of Indiana.[65] To exercise eminent domain, a pipeline company must apply to the Department of Natural Resources for issuance of a certificate of authority.[66] If the right of way or easement in question involves agricultural land, the

---

[51] IC 32-24.
[52] IC 32-24-1-2: A "condemnor" means any person authorized by Indiana law to exercise the power of eminent domain.
[53] IC 32-24-1-3.
[54] IC 32-24-4-2.
[55] IC 32-24-4-1: "Public Utility" refers to a person, firm, partnership, limited liability company, or corporation authorized to do business in Indiana. Indiana statute directly cites those authorized to furnish, supply, transmit, transport, or distribute gas, oil, or petroleum to the public or to any town or city.
[56] IC 32-24-1-3 (g).
[57] IC 32-24-1-3 (b).
[58] IC 32-24-1-3 (c).
[59] IC 32-24-1-4 (a).
[60] IC 32-24-1-5 (a).
[61] IC 32-24-1-5.9.
[62] As referred to in IC 14-39-1-2, "carbon dioxide transmission pipeline" means the part of a pipeline in Indiana, including appurtenant facilities, property rights, and easements, that is used exclusively for the purpose of transporting carbon dioxide to a carbon management application, including sequestration, enhanced oil recovery, and deep saline injection, within or outside Indiana.
[63] As referred to in IC 14-49-1-2.5, "underground storage of carbon dioxide" means the injection of carbon dioxide into, and storage of carbon dioxide in, underground strata and formations at the site of the carbon sequestration pilot project.
[64] IC 14-39.
[65] IC 14-39-1-3.
[66] IC 14-39-1-4.

condemner must compensate the owner by making a payment equal to 125% of the fair market value of the interest in the property acquired.[67] If the right-of-way/easement involves a parcel of residential property occupied by the owner, then it becomes 150% of the fair market value of the interest in the property acquired.[68] They must also pay any damages to the property owner if applicable. If the pipeline company cannot reach an agreement with the property owner, the operator of the carbon sequestration project may exercise the power of eminent domain to make the acquisition.[69]

Under Chapter 5 of Title 32, the underground storage of CO_2 in subsurface strata is also declared to be within the public interest of the people of Indiana and therefore qualifies as "public use." [70] Therefore, any person or organization in Indiana may condemn land, subsurface strata, and other necessary land for "constructing, mining, drilling, utilizing, and operating an underground gas reservoir."[71]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

The right to create a distinct interest in oil and gas in Indiana is established in IC 32-23-7-7. Oil and gas interests created "in, on, under, or beneath the surface" may be created for life, for a term of years, or in fee.[72] Title to the oil and gas interests may be vested in 1 or more people in sole ownership, tenancy in common, joint tenancy, or tenancy in the entireties.[73] Additionally, mineral interests can transfer ownership in the same manner as other real estate interests, in whole or in part.[74] Therefore, oil and gas interests may pass via conveyance of a recorded deed, lease, transfer on death deed, or land contract, as established in IC 32-21-4-1. Given that Indiana considers mineral estates as a type of real estate,[75] they are therefore also subject to property taxation under IC 6-1.1-2-1. A mineral interest in Indiana is an interest in any kind of coal, oil and gas, or other mineral that is conveyed by a grant, assignment, or reservation.[76] Although the term "mineral" was not found to be explicitly defined in Indiana law, IC 32-23-10-1 implies that a mineral can consist of coal, oil and gas, or other minerals. Oil and gas leases in Indiana become void after the elapse of 1 year since the last rental payment on the lease, or 1 year since oil and gas operations have ceased. In both cases, the landowner must also provide a written request and an affidavit.[77] However, lease owners can appeal the order and record of cancellation in the land's respective county court within 6 months of the cancellation.[78] Our research did not identify anything related to the manner in which Indiana courts interpret mineral contracts (or contracts in general if not specified).

Split Estates

Indiana statute (IC 32-23-7-7) addresses the creation of interests beneath the land surface. Under the Act, any grant or reservation in an instrument conveying or transferring oil and gas interests "in, on,

[67] IC 14-39-1-9 (a).
[68] IC 14-39-1-9 (b).
[69] IC 14-39-1-7 (b).
[70] IC 32-24-5-1 (b).
[71] IC 32-24-5-2 (a).
[72] IC 32-23-7-7 (b).
[73] IC 32-23-7-7 (c).
[74] IC 32-23-7-7 (d).
[75] "real property," as referred to in IC 6-1.1-1-15, includes "an estate in land located within this state, or an estate, right, or privilege in mines located on or minerals, including but not limited to oil or gas, located in the land, if the estate, right, or privilege is distinct from the ownership of the surface of the land."
[76] IC 32-23-10-1.
[77] IC 32-23-8-1.
[78] IC 32-23-8-4.

under, or produced from beneath the surface of the land" also transfers the right of the interest holder to enter the land to conduct oil and gas operations, or to determine the potential of the land for oil and gas operations.[79] They may also drill a well or a test well regardless of whether they are also the owner/lessee/licensee of the surface rights, and regardless if the owner of the remaining rights in the land consents to the entrance and drilling. In doing so, however, they must provide the surface owner advance written notice of their intent to enter the property.[80]

Indiana has adopted a dormant mineral act that can extinguish the title to a mineral estate. Under this act, any interest in coal, oil, gas, or "other" mineral that goes unused[81] for a period of 20 years will lapse and revert to the current surface owner of the property unless the mineral owner files a statement of claim in the local county recorder's office beforehand.[82] The exception is if an owner of 10 or more interests in the same county files a statement of claim that inadvertently omits some of those interests, in which case a supplemental filing made within 60 days of receiving actual notice of the lapse can preserve the omitted interests.[83]

Indiana is unique in that it contains a statutory provision allowing developers to harvest mineral rights on a plot of land where the owner is unknown, or if initial action to find the owner is unsuccessful.[84] Instead of stopping the process, developers can create an established lease for mineral rights through the court, which facilitates continuing of production activities. The legislation also allows for a lease and procedure to be created so that unknown mineral owners are compensated if or when they come forward with proof as the mineral rights owner within 7 years.

We have not found any discussion of how the Indiana courts might address the use of pore space for CO_2 storage incidental to development of the mineral estate.

Pore Space Ownership

It does not appear that Indiana has addressed the issue of pore space ownership by statute aside from its eminent domain laws. Our research did not find anything specific in the regulations or case law on pore space ownership in Indiana.

---

[79] IC 32-23-7-6.

[80] IC 32-23-7-6.5 (a).

[81] Under IC 32-23-10-3, a mineral interest is considered to be "in use" when minerals are produced under the mineral interest; operations are conducted on the mineral interest for injection, withdrawal, storage, or disposal of water, gas, or other fluid substances; rentals or royalties are paid by the owner of the mineral interest for the purpose of delaying or enjoying the use or exercise of the rights; a use described in subdivisions 1 through 3 is carried out on a tract with which the mineral interest may be unitized or pooled for production purposes; in the case of coal or other solid minerals, there is production from a common vein or seam by the owners of the mineral interest; or taxes are paid on the mineral interest by the owner of the mineral interest.

[82] 32-23-10-2.

[83] IC 32-23-10-5.

[84] IC 32-23-13.

Water Rights

Water rights in Indiana are regulated by the Indiana Utility Regulatory Commission and overseen by the Indiana DNR. Indiana statute declares that surface waters are public waters and therefore subject to regulation.[85] In general, surface waters fall under the doctrine of "beneficial use"[86] to the fullest extent.[87] For domestic purposes, riparian rights govern surface water in Indiana.[88] Domestic purposes, which includes water for household purposes and water for livestock/poultry/domestic animals, holds priority and is superior to all other water uses.[89] However, any person or organization can impound excess water and pump or divert water from a stream or lake when the flow[90]/lake level exceeds the existing reasonable uses at the time of the appropriation.[91] The exception is for diversion of water from the St. Lawrence River Basin—water may not be diverted "outside the basin from that part of the basin" within Indiana unless the diversion is approved by the governor of each Great Lakes state under the Water Resources Development Act.[92]

Additionally, the Commission may provide minimum stream flow quantities.[93] The water can be directly withdrawn from the reservoir impoundment or released from the reservoir impoundment to create increased flowage beyond normal stream flow for use by the contracting party or purchaser at a downstream point. The withdrawals or releases may not exceed the storage allocated to water supply purposes in the authorizing legislation for water supply or multiple purpose reservoir projects.

Usage of groundwater is also regulated by the beneficial use doctrine under Indiana statute.[94] Both groundwater and surface water users must report the volume of water used in a specific period to the Commission if requested. The Department can also designate restricted use areas in places where the withdrawal of groundwater either exceeds or threatens to exceed "natural replenishment."[95] In these restricted areas, a permit is required for anyone desiring to withdraw over 1,000,000 gallons per day. [96] The Department also requires records to be made of any new wells drilled within the area 30 days after its completion and placement into operation.[97] In an emergency, restricting regulations can be placed on a facility's ground water rights for causing a well failure or for causing "significant withdrawals" that exceed the recharge capability of the ground water resources in the area.[98]

Lithium Ownership and Extraction

No information was identified about mines that produce lithium or extensive lithium deposits in Indiana, and our research did not identify any Indiana state laws or regulations that address lithium extraction or mining.

---

[85] IC 14-25-1-10.
[86] As defined and referred to in IC-14-25-7-2, "beneficial use" means the use of water for any useful and productive purpose.
[87] IC 14-25-1-6.
[88] IC 14-25-1-3 (a).
[89] IC 14-25-1-3 (b).
[90] The standard units for the measurement of the flow of water are a cubic foot per second and a gallon per minute.
[91] IC 14-25-1-4.
[92] IC 14-25-1-11.
[93] IC 14-25-2-1.
[94] IC 14-25-3-3.
[95] IC 14-25-3-4 (a).
[96] IC 14-25-3-7.
[97] IC 14-25-3-12.
[98] IC 14-25-4-12.

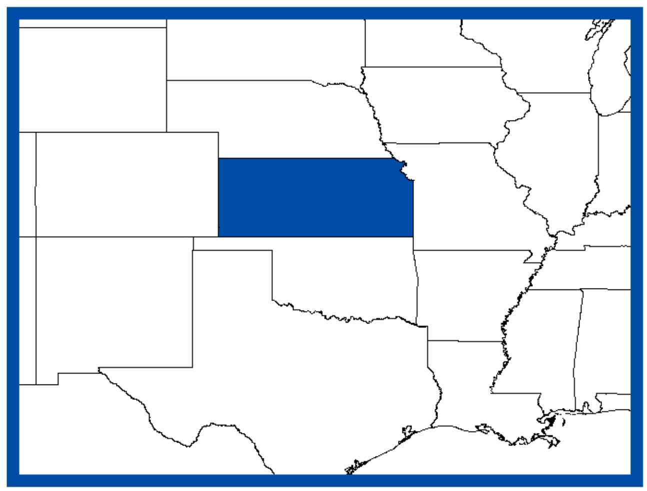
KANSAS

Executive Summary

There is significant potential for CCUS in Kansas. The state has a mature oil and gas production industry, with thousands of oil fields—from a few acres to very large fields—throughout the state. Current efforts to study the state's potential for CO_2 storage, including evaluation of the CO_2 storage capacity of several saline aquifers and consideration of a large cross-state pipeline that connects energy production areas to oil fields indicate a commitment to developing CCUS technology in Kansas. However, the current lack of CO_2 pipeline infrastructure in Kansas is a current challenge to CCUS development.

Background

Kansas includes federal, state, fee, and tribal land. Of the state's 52,510,720 acres of land, the federal government owns 253,919 acres, or 0.5% of this land.[1] As of FY2020, 109,227 acres of land are under BLM-administered oil and gas leases.[2] The state is home to four tribal lands: the Iowa, Kickapoo, Potawatomi, and Sac and Fox.[3] Two of these tribal lands, the Iowa and the Sac and Fox, extend across the state border into Nebraska.



Kansas operates under a common law legal system. The state's 105 counties are organized into 31 judicial districts, which are further grouped into six judicial departments and assigned to a Supreme Court justice.[4] Appeals may be taken from a district court to the Court of Appeals, which can further be taken to the Supreme Court. The 14-judge Court of Appeals hears all appeals from orders of the Kansas Corporation Commission (KCC)—which is the agency that oversees CCUS-related activities in the state—and all appeals from district courts in both civil and criminal cases, except those that may be appealed directly to the Supreme Court.

The KCC Conservation Division regulates oil and natural gas production activities in the state, including oversight of injection and production wells and pipeline safety.[5]

CCUS Activities the State

Kansas has a long history of oil and gas exploration. Following drilling of the first oil well in the state in 1860 in what is now Miami County,[6] the discovery of crude oil near Neodesha in 1892 is

---

[1] Congressional Research Service, Vincent, C. H., Bermejo, L. F., & Hanson, L. A., Federal Land Ownership: Overview and Data (2020). https://fas.org/sgp/crs/misc/R42346.pdf.

[2] *Programs: Energy and Minerals: Oil and Gas: Oil and Gas Statistics*. Bureau of Land Management. (n.d.). https://www.blm.gov/programs-energy-and-minerals-oil-and-gas-oil-and-gas-statistics.

[3] *American Indians in Kansas*. Kansas Historical Society. (2020, November). https://www.kshs.org/kansapedia/american-indians-in-kansas/17881.

[4] Congressional Research Service, Vincent, C. H., Bermejo, L. F., & Hanson, L. A., Federal Land Ownership: Overview and Data (2020). https://fas.org/sgp/crs/misc/R42346.pdf.

[5] K.S.A 55-151, 55-152.

[6] Oil and gas production in Kansas. Downloaded on June 30, 2021 from https://geokansas.ku.edu/oil-and-gas-production-kansas.

considered the first significant oil find west of the Mississippi River.[7]

The Kansas Geological Survey (KGS) maintains data related to oil and gas production in the state, including historical data and production data by county, lease, operator, and field. According to the KGS, total oil production in Kansas for 2020 was 24,599,638 barrels, and total gas production in 2020 was 157,192,120 mcf (thousand cubic feet).[8] Annual oil production has averaged about 30 million barrels[9] over the last 20 years (although a drop in 2020 is noted, likely reflecting decreased production due to the COVID-19 pandemic).[10]

Crude oil and natural gas fields are found in several geologic basins across Kansas, particularly in the southwestern, central, and eastern parts of the state.[11, 12] KGS maintains data on over 7,000 oil fields in the state that range in size from 10 to 7,350,400 acres.[13] The ten largest fields in the state (the Bemis-Shutts, Santa Fe North, Chase-Silica, Trapp, Hall-Gurney, El Dorado, Burrton, Fairport, Paola-Rantoul, and Damme) amounted to about 15% of this total acreage.

As of June 5, 2021, there are 68,352 producing oil wells and 24,520 producing gas wells in Kansas.[14] There are also thousands of Class II injection wells used for secondary/enhanced oil recovery and to dispose of salt water that is produced during oil and gas production. According to June 2021 statistics maintained by KGS, there are 8,737 Class II EOR wells and 5,334 wastewater disposal wells in the state.[15] No statistics are available about the number of wells or fields where CO_2 flooding for EOR is performed. While the KCC regulates Class II wells in Kansas, other types of injection wells are regulated by either the Kansas Department of Health and Environment (Class I, III, IV, and V wells) or US EPA (Class VI wells).

There do not appear to be any significant natural CO_2 reserves in Kansas. Current research into CCUS is focused on injection of CO_2 that is generated by energy plants, many of which are located in the northeastern part of the state. In 2018, CO_2 emissions for Kansas totaled 62.4 million metric tons of CO_2 averaging 0.02 metric tons per capita; the total emissions include 21.7 million metric tons from coal, 23.6 million metric tons from oil, and 17.1 million metric tons from gas.[16] CO_2 sources in Kansas include ethanol plants, fertilizer facilities, power-generation facilities, refineries, and cement kilns. Large stationary sources of CO_2 include the Coffeyville Fertilizer Plant, Arkalon Ethanol Plant, Bonanza Ethanol Plant, and Conestoga Ethanol Plant. According to KGS, the highest density of CO_2 sources in the state is along the eastern border with Missouri.[17, 18]

---

[7] US Energy Information Administration. Kansas quick facts. Downloaded on July 6, 2021 from https://www.eia.gov/state/analysis.php?sid=KS#19.

[8] Kansas Geological Survey. Accessed from http://www.kgs.ku.edu/PRS/Info/topTen.html on July 6, 2021.

[9] Oil and gas production based on data downloaded from http://www.kgs.ku.edu/PRS/petro/state.html on July 6, 2021.

[10] US Energy Information Administration. Kansas quick facts. Available at https://www.eia.gov/state/analysis.php?sid=KS#19.

[11] The map is available at https://maps.kgs.ku.edu/oilgas/index.html.

[12] US Energy Information Administration. Kansas quick facts. Available at https://www.eia.gov/state/analysis.php?sid=KS#19.

[13] Based on data downloaded from http://www.kgs.ku.edu/Magellan/Field/index.html on July 6, 2021.

[14] KGS. Oil and Gas Well Statistics for Kansas. Updated June 5, 021. Accessed at http://www.kgs.ku.edu/PRS/wellStats.html.

[15] Ibid

[16] From https://knoema.com/atlas/United-States-of-America/Kansas/CO2-emissions; accessed on July 8, 2021.

[17] Kioga, CCUS Opportunities Kansas, 8-13-2018. Available at http://www.kgs.ku.edu/PRS/ICKan/2018/KIOGA_2018_Dubois.pdf.

[18] Kansas Geological Survey. Public Information Circular 27. Available at http://www.kgs.ku.edu/Publications/PIC/PIC27_2011.pdf.

Estimates of available CO_2 storage resource capacity in oil and gas reservoirs and saline formations of Kansas vary from between 2.7 to 5.4 billion tons[19] and 10.88 to 86.34 billion metric tons.[20] One source estimates that Kansas has geologic space to sequester almost 70 years' worth of the state's stationary CO_2 production. [21]

The Osage, Viola, and Arbuckle Groups are the primary targets for CO_2 storage in western Kansas.[22] These extensive sedimentary formations contain saline water and are separated from freshwater aquifers by thousands of feet of impermeable rock, and therefore offer an opportunity to hold large volumes of CO_2, while ensuring confinement from USDWs, as required by the federal UIC regulations. Past oilfield wastewater disposal activities provide a strong indicator of the potential for CO_2 storage and containment: brine from thousands of oil wells has been emplaced in the Arbuckle and other formations, indicating the reservoirs might safely contain CO_2 as well. The Arbuckle Formation, which is present across the southern part of Kansas, appears to be the most heavily studied saline formation in the state. Modeling studies estimate that the total CO_2 storage capacity across 10 sites is 780 million tons of supercritical CO_2, with some sites, such as Dexter Field in south central Kansas, providing 121 million tons of CO_2 storage,[23] and found that most of the sites studied could be considered as commercial scale CO_2 storage reservoirs from a perspective of available pore space. The Pleasant Prairie site within the Hugoton Gas Field in southwest Kansas has been estimated to have a CO_2 storage capacity within the Osage, Viola, and Arbuckle formations of more than 50 million tons injected over a 25-year period.[24]

There is intensive research into evaluating the potential for CCUS in Kansas, and much of this research is led by US DOE or the KGS, primarily through the CarbonSAFE (Carbon Storage Assurance Facility Enterprise) initiative. The purpose of the Integrated Carbon Capture and Storage for Kansas (ICKan) Phase I pre-feasibility[25] is to identify and critically evaluate challenges for CCUS in Kansas, including a feasibility study of three of Kansas' largest CO_2 point sources, nearby storage sites with greater than 50 million metric tons capacity, and potential CO_2 transportation networks to determine the economic feasibility of CCUS.[26]

KGS worked with industry partners on studies of injection of 20,000 tons of CO_2 for EOR at Wellington Field (under DOE project DEFE0006821) and of 7,000 tons of CO_2 in the Hall-Gurney Field (under DOE project DE-AC-00BC15124).[27] KGS also submitted a Class VI permit application to US

[19] W. L. Watney, R. Buchanan, and J. Rush. Geologic Carbon Sequestration -- Characterizing Pore Space & Managing CO_2 Plume. Presented to Joint Committee on Energy and Environmental Policy. October 18, 2011.
[20] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[21] W. L. Watney, R. Buchanan, and J. Rush. Geologic Carbon Sequestration -- Characterizing Pore Space & Managing CO_2 Plume. Presented to Joint Committee on Energy and Environmental Policy. October 18, 2011.
[22] Buchanan, Rex and Carr, T. Geologic Sequestration of Carbon Dioxide in Kansas. KGS Public Information Circular 27. Available at http://www.kgs.ku.edu/Publications/PIC/pic27.html.
[23] Holubnyak et al. 2017. Calculation of CO_2 Storage Capacity for Arbuckle Group in Southern Kansas: Implications for a Seismically Active Region. Energy Procedia. Volume 114, Pages 4679-4689. Available at https://www.sciencedirect.com/science/article/pii/S1876610217317939.
[24] Quarterly report: Award Number: DE-FE0029474 Integrated CCS for Kansas (ICKan). July 2018. Downloaded from http://www.kgs.ku.edu/PRS/ICKan/2018/July/Q5_7-17-2018_FINAL.pdf.
[25] Project DE-FE0029474.
[26] Bidgoli, T. and Dubois, M. Integrated CCS for Kansas (ICKan). Project Number FE0029474. Presented at the Carbon Storage and Oil and Natural Gas Technologies Review Meeting. August 1-3, 2017.
[27] *CarbonSAFE Phase II: Integrated Midcontinent Stacked Carbon Storage Hub*. Kansas Geological Survey. (n.d.). http://www.kgs.ku.edu/PRS/IMSCSH/about.html.

EPA for geologic sequestration at the Wellington Field;[28] however, no permit was issued. Building upon the regional characterization studies conducted under DOE project FE0002056, CarbonSAFE projects will conduct high-level technical sub-basinal evaluations of CO_2 storage, including risk assessment, and modeling.

There is an extensive network of pipelines delivering crude oil to the state's three refineries.[29] There are currently only two small-scale CO_2 pipelines in Kansas that connect point sources of industrial CO_2 (including the Coffeyville Chemical Plant) with newer CO_2-EOR projects in oil fields (e.g., the North Burbank field in Oklahoma).[30] However, a study presented to DOE as part of the CarbonSAFE Program considers the potential for a 300-mile cross-state pipeline connecting CO_2 sources (including the power plants at the Jeffrey Energy Center in northeastern Kansas) to the sedimentary basins in southwestern Kansas in the Arbuckle and Simon formations.[31] Investigation into the construction of additional pipelines to accommodate CO_2 are underway. For example, a pipeline under consideration would accommodate transport of ethanol-sourced CO_2 from Iowa and Nebraska into Kansas.[32]

The current lack of CO_2 pipeline infrastructure in Kansas means that significant CO_2 pipeline construction would need to occur if CCUS became commercially attractive for internal stakeholders. There are cost and capacity implications for the type of pipeline constructed, ranging from high-capacity trunk-lines to lower-capacity feeder lines. Currently, there is no published research regarding the repurposing of natural gas pipelines for CO_2 transportation. While they are both gases, they will behave differently at supercritical conditions, forcing the pipeline to meet various operation criteria such as pressure, temperature, and diameter.

Classification of CO_2: Commodity and Pollutant

The Kansas statutes do not specifically contemplate CO_2 in the state's mineral severance tax codes. However, for purposes of taxation, "gas" is defined as "natural gas, and all other raw, unrefined gas or gases, all constituent parts of any such gas or gases and refined products derived from any such gas or gases."[33] These gases can be taken from below the surface of the earth or water, regardless of whether from a gas well or from a well also productive of oil or any other product.[34] As such, CO_2 would be classified as a gas and therefore subject to an excise tax upon its severance and production for sale, transport, storage, profit, or commercial use.[35]

---

[28] *CarbonSAFE Phase II: Integrated Midcontinent Stacked Carbon Storage Hub*. Kansas Geological Survey. (n.d.). http://www.kgs.ku.edu/PRS/IMSCSH/about.html.

[29] US Energy Information Administration. Kansas quick facts. Downloaded on July 6, 2021 from https://www.eia.gov/state/analysis.php?sid=KS#19.

[30] US DOE. Office of Fossil Energy, National Energy Technology Laboratory. A Review of the CO_2 Pipeline Infrastructure in the U.S. April 21, 2015. DOE/NETL-2014/1681.

[31] DE-FE0029474: Integrated Carbon Capture and Storage for Kansas Phase I pre-feasibility study.

[32] Kioga, CCUS Opportunities Kansas, 8-13-2018. Available at http://www.kgs.ku.edu/PRS/ICKan/2018/KIOGA_2018_Dubois.pdf.

[33] K.S.A 79-4216(c).

[34] Ibid.

[35] K.S.A 79-4217.

Kansas also classifies CO_2 as an air pollutant. The Kansas Air Quality Act defines "air contaminants" as any dust, fumes, smoke, other particulate matter, vapor, gas, odorous substances, or any combination thereof, and "air pollution" as "the presence in the outdoor atmosphere of one or more air contaminants in such quantities and duration as is, or tends significantly to be, injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or property, or would contribute to the formation of regional haze."[36]

By statute, CCUS properties and electric generation units that capture and sequester all CO_2 and other emissions are exempted from Kansas property taxes. CCUS properties are defined in the statute to include equipment used to capture or convert anthropogenic CO_2, CO_2 injection wells, and equipment used to recover CO_2 for sequestration.[37] Additionally, the state's Carbon Dioxide Reduction Act provides a tax deduction for CCS equipment.[38]

House Bill No. 2290 was introduced by Representative Coleman on February 9, 2021. It proposed to assess carbon content charges upon sales of certain fuels, increasing from $100 per metric ton in 2025 to $300 per metric ton in 2029 to fund a carbon dividend program fund that would be distributed to Kansas taxpayers. The bill died in Committee.[39]

Based on the state's Carbon Dioxide Reduction Act, which requires KCC to adopt rules and regulations for CO_2 storage, one could interpret this as an indication that the state considers CO_2 to be an air pollutant (i.e., something that is harmful and that should not be released to the atmosphere).

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

The Kansas Corporation Commission oversees all activities associated with oil and gas production in the state, including oil and gas production wells, Class II injection under the state's delegated UIC Program, and pipeline safety. No tribal or local laws or regulations address these activities within the state. The Commission has three statutory duties: to protect correlative rights, to prevent waste, and to protect fresh and usable water.[40]

Pipeline Regulations

According to Kansas statute, pipelines for the conveyance of crude oil are considered common carriers and are regulated by KCC.41 Through certification by the US Pipeline & Hazardous Materials Safety Administration's Office of Pipeline Safety (OPS), the state inspects and enforces the pipeline safety regulations for intrastate gas pipeline operators in Kansas. This work is performed by KCC's Pipeline Safety Section.

The State's "Rules for Transportation of Natural and Other Gas by Pipeline: Minimum Safety Standards" incorporate the federal pipeline rules at 49 CFR Part 192 by reference, with provisions for pipeline design, construction, and corrosion control, testing, operation, and maintenance.[42] Subpart Q of the state's regulation contains additional requirements added by Kansas; these pertain to inspections, annual and incident reports, construction notices, and provisions for applying for waivers of the requirements. While the title of the rule implies that it applies to other gasses besides natural gas, our research identified nothing specific in the rules related to CO_2 in gaseous or supercritical form.

36 K.S.A 65-3002.

37 K.S.A. 79-233.

38 Kan. Stat. Ann. § 79-32,256.

39 KS HB2290

40 From Oil & Gas (ks.gov).

41 K.S.A 55-501.

42 K.A.R. 82-10, 82-11; Amended July 21, 2011.

Laws and Regulations for CO_2 Storage

The Carbon Dioxide Reduction Act requires the KCC to adopt requirements, procedures, and standards for the safe and secure injection of CO_2 and maintenance of underground storage of CO_2.[43] Kansas adopted draft rules for CO_2 storage facilities that included requirements for Class VI injection wells on February 26, 2010 (K.A.R. 82-3-1100 through 82-3-1120); however, the rules were revoked on August 14, 2015. The prior Kansas rules mirrored many aspects of the federal Class VI Rule. Currently, Class VI wells in Kansas are overseen by EPA Region 7, and are subject to the federal Class VI Rule at 40 CR 146.81 et seq. The state currently has no rules for Class VI injection, long-term site care, and financial liability for CCUS. There are currently no permitted Class VI injection wells in Kansas.

The 2019 Kansas Statutes established the Carbon Dioxide Injection Well and Underground Storage Fund[44] to be administered by KCC to cover the cost of development and issuance of permits and compliance monitoring, oversight, and enforcement activities, as well as the costs of closure, long-term monitoring, and emergency or long-term remedial activities. The Statute specifies that Kansas will not be held liable or financially responsible for any damages resulting from the leak or discharge of CO_2 from any CO_2 injection well or the underground storage of CO_2.[45] Moneys within the fund are authorized for permitting activities, long-term monitoring, remedial actives, legal costs, and well closures, among others.[46] Our research did not identify the extent to which the fund has been established.

Regulation of Oil and Gas Production

KCC's requirements for oil and gas production wells are contained within the "General Rules and Regulations for the Conservation of Crude Oil and Natural Gas" at Chapter 82, Article 3 of the Kansas Administrative Regulations (K.A.R.).[47] Prospective oil or gas production well operators must submit written notice of their intent to drill a well or wells to the Commission and obtain a license.[48] The notice must provide information about the well, including its construction, depth, the deepest formation perforated, and depth to fresh water. Drilling may not commence without approval from the Commission.[49] The rules also contain requirements for appropriate cementing and casing.[50] Oil or gas wells may not be drilled nearer than 330 feet from any lease or unit boundary line, unless an exception is approved.[51]

Oil well operators are subject to a hearing if the Commissioner believes that the operator has violated rules or regulations.[52] Any requests for transfer of operator responsibility must be made with at least 30 days' notice to the Commissioner.[53]

KCC may order the unitization and unit operation of a pool or part of a pool if all of the following conditions exist: oil and gas production has diminished to below economic levels; the unitization of a pool/portion of a pool is deemed economically feasible and necessary to increase the recovery of oil or gas; the value of estimated additional recovery from unitization exceeds the associated costs to conducting operations; and the proposed operation is equitable to all interest owners involved.[54]

---

[43] K.S.A. 2017 Supp. 55-1636 through 55-1640, 55-1641, 79-233 and 79-32,256.
[44] K.S.A 55-1638.
[45] K.S.A 55-1641.
[46] Ibid.
[47] Under statutory authority of K.S.A. 2014, Supp. 55-152, K.S.A. 55-604, K.S.A. 55-704.
[48] K.S.A 55-155.
[49] K.A.R. 82-3-103.
[50] K.A.R. 82-3-105, 106.
[51] K.A.R. 82-3-108.
[52] K.A.R 82-3-122.
[53] K.A.R 82-3-136.
[54] K.S.A 55-1304.

Operators seeking to unitize a pool must apply to KCC (and provide a description of the pool, planned production, and the allocation to the separate tracts within the unit), and unitization orders must be approved by the owners of at least 75% of production that will be credited to royalties.[55] Alternatively, if all mineral and royalty owners and at least 90% of the working interest owners approve a contract for unit operation, application to the KCC is not necessary.[56]

Regulation of Injection Activities

Kansas has Class II UIC program primacy under Section 1425 of the SDWA, granted on February 9, 1984 to the KCC.[57] KCC regulates Class II injection wells, (including those used for enhanced oil recovery and wastewater disposal), and the injection well regulations are found in K.A.R. 82-3-400 through K.A.R. 82-3- 412. The primary concern of the injection well regulations is to protect fresh and usable water, and they follow national guidelines under the federal SDWA to protect USDWs from harm due to improper injection. Owners or operators of Class II injection wells are subject to technical requirements for well construction, operation, monitoring, mechanical integrity testing, and plugging.

All new injection wells[58] in Kansas require a permit.[59] Class II permit applications must include information about: the location of the injection well; the status of wells within a one-half mile area of review around the well; the injection interval; the casing, tubing, and cement; the results of an electric log; and the fluid to be injected.[60] Injection wells must be cased and the casing cemented to isolate hydrocarbon sources or fresh and usable water resources. Permit applications are subject to public notice and public hearing.

Environmental Laws

The Kansas Air Quality Act outlines protections related to air quality control. The Act grants the secretary of the Department of Health and Environment the ability to classify air contaminant sources that may cause or contribute to air pollution.[61] In addition, air contaminant emission sources must monitor their emissions, operating parameters, and their impact on their surroundings.[62] The statute does not identify CO_2 or methane directly, but it does define "air contaminant" as any dust, fumes, smoke, other particulate matter, vapor, gas, odorous substances, or any combination thereof, but not including water vapor or steam condensate. "Air pollution" is defined as a concentration of one or more air contaminants in such amounts that it is considered to be harmful to human, animal, and plant life, property, and cause regional haze.[63] The Kansas Air Quality Regulations reference national ambient air quality standards. Under these standards, methane is designated as a type of "volatile organic compound" that has negligible photochemical activity and thus is excluded from regulations applicable to volatile organic compounds.[64]

Induced seismicity resulting from large volume wastewater injection into the Arbuckle Formation is a concern in Kansas. In 2014, the state developed the Kansas Seismic Action Plan (KSAP), which consists of an enhanced seismic monitoring network and a response plan. The response plan identifies actions that are triggered if a particular seismic event results in the exceedance of a risk-based threshold seismic action score (SAS), which is calculated based on a formula that considers the magnitude,

---

[55] K.S.A 55-1305.
[56] K.S.A 55-1317.
[57] 49FR4735.
[58] New injection wells are those wells not authorized by order of the Commission on or before December 8, 1982.
[59] K.A.R. 82-3-400(a).
[60] K.A.R. 82-3-401.
[61] K.S.A 65-3007 (a).
[62] K.S.A 65-3007 (b).
[63] K.S.A 65-3002.
[64] K.A.R 28-19-61.

clustering, and timing of seismic events. Potential response to events based on the score may range from no action to geologic evaluations of fault data, to potential changes to injection operations.[65] US EPA typically considers evaluations of seismic potential in Class VI permits[66] and the increased seismic activity also prompted KDHE to implement a Waste Minimization Plan to be included in Class I injection permits.[67]

Industrial Siting Requirements

Our research did not identify any statutes or regulations that govern the siting of oil and gas fields, pipelines, or energy utilities in Kansas.

Eminent Domain

Kansas authority for eminent domain is outlined in Kansas Statutes and in the Kansas Constitution. Article 13, Section 4 of the Kansas Constitution provides that "no right of way shall be appropriated to the use of any corporation, until full compensation therefore be first made in money, or secured by a deposit of money, to the owner, irrespective of any benefit from any improvement proposed by such corporation."[68] This same language is reiterated in Kansas statute, which declares that "Private property shall not be taken or damaged for public use, and shall not be taken without just compensation."[69] Kansas has not statutorily defined the requirements for "public use," although it is assumed that oil and gas transportation pipelines, which qualify as public utilities and are declared common carriers under Kansas Statutes,[70] may satisfy the public use requirement. Additionally, state law forbids taking of private property by eminent domain for the purpose of "selling, leasing, or otherwise transferring such property of any private entity.[71] Exceptions to this rule include public utilities[72] and pipeline companies."[73]

Chapter 26 of Kansas' statutes outlines the procedure for exercising eminent domain. Any corporation issued a "certificate of convenience" by the KCC can exercise their right to eminent domain.[74] To do so, a petition must be verified in the district court of the county in which the real estate is situated, demonstrating the entity's *authority* to eminent domain and their *intent*.[75] If the real estate is in more than one county, proceedings can be brought to either county. The judge subsequently will order an appraisal of the lots in question, and the appraisers will file a report with the district court and notify the condemner of the filing for a survey.[76] Compensation to the landowners depends on how much of the land is taken and for what purpose: if the entire tract of land or interest in the land is taken, the measure of

---

[65] Kansas Seismic Action Plan. Available at https://www.kansas.com/news/state/article1491084.ece/BINARY/PDF%20-%20State%20of%20Kansas%20Seismic%20Action%20Plan.pdf.

[66] US EPA. Underground Injection Control Program Class VI Implementation Manual for UIC Program Directors. EPA 816-R-18-001. January 2018.

[67] From https://www.kdheks.gov/uic/

[68] KS Const. art XIII §4.

[69] K.SA. 26-513.

[70] K.S.A 66-104 and K.S.A 55-501.

[71] K.S.A 26-501a.

[72] The term "public utility," as defined in K.S.A 66-104, does include "corporations, companies, individuals, and/or associations that plant or generate machinery…for the conveyance of oil and gas through pipelines in or through any part of the state, except for pipelines less than 15 miles in length and not operated in connection with or for the general supply of gas or oil."

[73] K.S.A 26-501a.

[74] K.S.A 26-101.

[75] K.S.A 26-501.

[76] K.S.A 26-504 – K.S.A 26-512.

"just compensation" is the fair market value.[77, 78] If only a part of the land or interest is taken, the compensation is the difference between the fair market value immediately before the property is acquired, and the value of the property or interest remaining immediately after.[79] Additionally, property owners are required to receive at least 200% of the fair market value if the Kansas legislature authorizes eminent domain for private economic development purposes.[80] Natural gas public utilities may also exercise eminent domain procedure for the underground storage of natural gas if they obtain a certificate from the Commission.[81]

Cities also can acquire any interest in real property through condemnation. Under Kansas statute, the city can appropriate private property for its use whenever it is deemed "necessary" by the city's governing body.[82] To do so, they must create a resolution detailing the necessity of the project and authorize a survey.

At present, Kansas' statutory definition for a public utility does not appear to include the usage of eminent domain statute to acquire pore space from property owners.

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Kansas recognizes that a mineral interest is an interest in real property.[83] As defined in the Kansas Statutes, Annotated (K.S.A.), a "mineral interest" means an interest created by an instrument transferring, by grant, assignment, reservation or otherwise, an interest of any kind in coal, oil, gas or other minerals.[84] Severance of the mineral rights from the surface can occur by either granting the mineral rights expressly or by granting the surface rights and listing the mineral rights as an exception.[85]

Title to mineral rights in the state of Kansas is conveyed by usage of a mineral deed.[86] When determining the scope of a mineral conveyance, Kansas courts have typically studied the intent of the parties involved.[87] This process begins with a four corners[88] search of the deed to identify the original purpose through the plain meaning of the words.[89] If the intent of the parties is not clear and the meaning of the words remains uncertain, the court applies various rules of construction to discern a "presumed" intent.[90] If the intent of the parties is still ambiguous even after applying rules of construction, the courts will consider extrinsic evidence relating to the contract.[91]

---

[77] The term "Fair market value" as defined in K.S.A 26-513(e) means the amount in terms of money that a buyer is justified in paying, and that a seller is justified in accepting, for property in an open and competitive market. The term assumes that the parties are acting without "undue compulsion."
[78] K.S.A 26-513(b).
[79] Ibid.
[80] K.S.A 26-501b(f).
[81] K.S.A. 55-1205.
[82] K.S.A 26-201.
[83] Froelich United Royalty Co., 178 Kan. 503, 507, 290 P.2d 93, 96 (1955), modified, 179 Kan. 652, 297 P.2d 1106 (1956).
[84] K.S.A. 55-1601.
[85] David A. Pierce. 1988. Ten Things Kansas Attorneys Should Know about Oil and Gas Law.
[86] 170 Kan. 419, Syl. ¶¶ 1 and 2, 227 P.2d 136 (1951).
[87] In re Estate of Trester, 172 Kan. 478, 482-83, 241 P.2d 475, 478 (1952).
[88] The Four Corners rule is a legal doctrine used to determine the meaning of a contract by its written language only.
[89] Heyen v. Hartnett, 235 Kan. 117,122,679 P.2d 1152, 1156-57 (1984).
[90] Brungardt v. Smith, 178 Kan. 629, 636, 290 P.2d 1039, 1044 (1955).
[91] Heyen v. Hartnett, 235 Kan. 117,679 P.2d 1152 (1984).

Kansas Courts have further found that the term "mineral" itself does not have a clear meaning and is therefore "susceptible to limitations according to the intent of the parties involved."[92] This issue was raised in *Roth v. Huser* in determining whether an exception that reserved the "mineral deposits" to the grantor included oil and gas. In their finding, the trial courts determined that the substances were known to exist in the area, and therefore the parties involved could have anticipated the encompassment of oil and gas in the term "mineral deposits" at the time of conveyance.[93] This "community knowledge test"[94] asserted that substances could only be included in the definition of "mineral" if they were generally known to exist at the time of the conveyance.[95] This same test was later employed in *Keller v. Ely*, in which the Kansas Court held that a reservation of "oil, gas, casing-head gas, and other liquid semi-solid and solid materials" did not include gypsum, given that gypsum was being mined in the area at the time the conveyance was made and therefore the parties had the ability to specify it.[96]

Split Estates

The title to minerals underlying a tract of land in Kansas can be severed from surface ownership rights to create two distinct property interests: a surface estate and a mineral estate. Per the Kansas Surface Owner Notification Act, oil and gas well operators must provide notice to the surface owner of their intent to drill a well,[97] transfer well ownership,[98] or plug a well.[99] The KCC provides this notice to the surface owner if the operator does not.

A mineral estate in Kansas has an implied right to use of the surface estate in developing the land; however, Kansas does not consider the mineral estate to be dominant to the surface estate.[100, 101] Additionally, the State has adopted a Dormant Mineral Act which can extinguish the title to a mineral estate and reunite it with the surface estate.[102] Under this statute, any interest in coal, oil, gas or other minerals, if "unused" for a period of 20 years, will lapse and revert to the current owner unless a statement of claim is filed prior to the end of the 20-year period.[103, 104] Upon the lapse of the mineral interest, the owner of the surface estate must provide notice to the severed mineral interest owner by

---

92 In re Estate of Trester, 172 Kan. 478, 482-83, 241 P.2d 475, 478 (1952).
93 Roth v. Huser, 147 Kan. 433, 76 P.2d 871 (1938).
94 Community knowledge tests are a rule of construction employed by courts to interpret the scope of mineral conveyances.
95 Pierce, D. E. (1988). Toward a Functional Mineral Jurisprudence for Kansas. *Washburn Law Journal*, 27(2), 225.
96 Keller v. Ely, 192 Kan. 698, 701, 391 P.2d 132, 135 (1964).
97 K.A.R. 82-3-1204.
98 K.S.A. 55-155.
99 K.S.A 55-169b.
100 Thurner v. Kaufman, 237 Kan. 184, 188, 699 P.2d 435, 439 (1984).
101 Rostocil v. Phillips Petroleum Company, 210 Kan. 400, 502 P.2d 825 (1972).
102 K.S.A. §§ 55-1602.
103 Ibid.
104 A mineral interest is considered to be "in use" when minerals (including oil or gas) are produced from the property; Operations are being conducted on the property for the injection, withdrawal, storage, or disposal of water, gas, or other fluid substances; Rentals or royalties are being paid by the owner of the severed mineral interest to the owner of the severed surface estate for the purpose of delaying or enjoying the use of the mineral rights; The property is unitized or pooled for oil or gas production purposes with other property that is being used under this definition. In the case of coal or other solid minerals, there is production from a common vein or seam by the owners of the severed mineral interests, or taxes are being paid on the severed mineral interest by the owner. [K.S.A. §§ 55-1603]

publishing notice of the lapse in a newspaper of general circulation in the county where the mineral interest is located.[105] This provision does not apply to land with producing wells.[106]

We have not found any discussion of how the Kansas courts might address the use of pore space for CO_2 storage incidental to development of the mineral estate.

Pore Space Ownership

Kansas has not yet addressed the issue of pore space ownership by statute. In 2011 and 2012, House Bill Number 2164 and Senate Bill 271 were introduced in the Kansas General Assembly to address pore space ownership, but both were defeated. [107] In its statutory absence, the 1910 court case *Mound City Brick & Gas Co. v. Goodspeed Gas & Oil Co.* has been cited to support the conveyance of pore space rights to the mineral estate.[108] The case involved whether the failure of an appellant to record a lease within 90 days of its execution and to list the property for taxation purposes rendered the lease null and void. Despite oil and gas being an integral part of the land, the court held that "[t]he stratum in which they are found is capable of severance, and by an appropriate writing the owner of the land may transfer the stratum containing oil and gas to another…such party acquires an estate in and title to the stratum of oil and gas, and thereafter it becomes the subject of taxation, encumbrance, or conveyance."[109] Given that the entire stratum could be severed and not just the minerals, it is believed that the pore space would also be conveyed with the mineral estate instead of remaining with the surface estate.[110]

Water Rights

The Kansas Water Appropriation Act declares that water rights are considered "a real property right appurtenant to and severable from the land on or in connection with which the water is used, and such water right pass as an appurtenance with a conveyance of the land by deed, lease, mortgage, will, or other disposal, or by inheritance."[111] All waters within the state may be appropriated for beneficial use; however, to ensure "base flow" in certain streams and to protect wildlife and water quality, the state also enforces "minimum desirable streamflow" (MDS) requirements. [112] When flows drop below an established threshold, pumping restrictions are imposed; this applies to permits or water rights granted after the MDS provision was enacted in 1984.[113]

Kansas adheres to the doctrine of prior appropriation for water administration.[114] In cases where lawful uses of water have the same date of priority, the state prioritizes users in the following order of preference for usage: domestic, municipal, irrigation, industrial, recreational, and water power uses.[115] Such appropriations do not constitute ownership of the water, and instead remain subject to the principle of beneficial use. Kansas' Department of Agriculture's Division of Water Resources issues permits to

---

[105] K.S.A. §§ 55-1605.
[106] K.S.A 55-1613.
[107] https://www.kslegislature.org/.
[108] Gray, T. (2015). A 2015 Analysis and Update on U.S. Pore Space Law —The Necessity of Proceeding Cautiously With Respect to the "Stick" Known as Pore Space. *Oil and Gas, Natural Resources, and Energy Journal,* 1(3), 294.
[109] Mound City Brick & Gas Co. v. Goodspeed Gas & Oil Co., 109 P. 1002,1003.
[110] Gray, T. (2015). A 2015 Analysis and Update on U.S. Pore Space Law —The Necessity of Proceeding Cautiously With Respect to the "Stick" Known as Pore Space. *Oil and Gas, Natural Resources, and Energy Journal,* 1(3), 295.
[111] K.S.A. 82a-701.
[112] K.S.A. 82a-703.
[113] Ibid.
[114] K.S.A. 82a,707c.
[115] K.S.A 82a-707b.

appropriate water. The Department also regulates water usage and documents and records all water rights in the state.[116]

For purposes of regulating oil and gas production and Class II injection wells to ensure environmental protection, Kansas regulations and statutes define "freshwater" and "usable water." Freshwater is defined in K.A.R. 82-3-101(34) as water containing not more than 1,000 milligrams of total dissolved solids per liter, and is considered in the drilling of oil and gas wells. Usable water is defined for the purposes of injection well construction as water containing no more than 10,000 milligrams per liter of total dissolved solids,[117] consistent with the federal definition of a USDW.

We have not found any information regarding whether a city or town may exercise eminent domain powers to acquire water rights or necessary real and personal property for the purpose of providing an adequate water supply for municipal and domestic purposes. Kansas statute does specify that every vested right of prior appropriation/diversion of water for industrial uses is subject to the right of eminent domain and can therefore be condemned and compensated for in the same process as other private property.[118]

Lithium Ownership and Extraction

Our research did not identify any Kansas state laws or regulations that address lithium extraction or mining. No information was identified about mines that produce lithium or extensive lithium deposits in Kansas.

[116] K.S.A. 82a-705.
[117] K.S.A. 55-150(i).
[118] K.S.A 42-309.

LOUISIANA

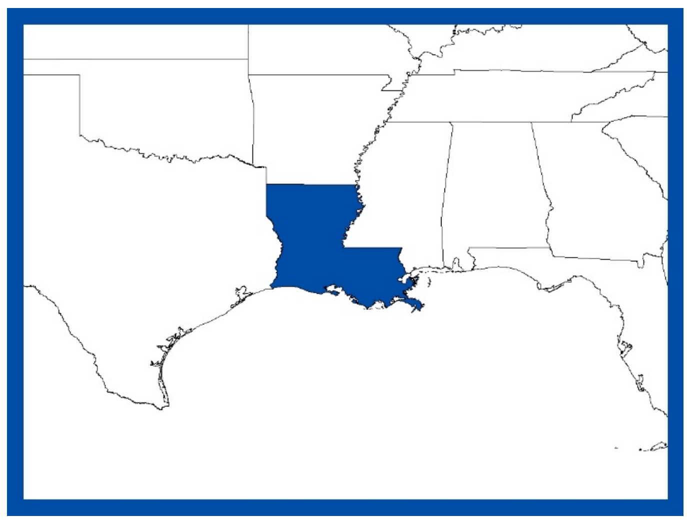
Executive Summary

The government of Louisiana has prioritized advancement of CCUS and the development of a carbon management economy. Co-location of refineries and sinks along the state's "industrial corridor" offers significant opportunity for CCUS. Additionally, the state's Geologic Sequestration of Carbon Dioxide Act and Carbon Dioxide Trust Fund, impending Class VI primacy for CO_2 injection wells, and explicit inclusion of CO_2 storage facilities in the state's eminent domain provisions provide regulatory certainty to potential CCUS project developers.

Background

Louisiana extends 19,847,840 acres, of which 4.7% (or 1,353,291 acres) are owned by the federal government. The majority of this public land is dispersed in the center of the state.

There are four federally recognized tribes in Louisiana: the Tunica-Biloxi Indian Tribe, the Coushatta Tribe of Louisiana, the Jena Band of Choctaw Indians, and the Chitimacha.[1] The Tunica-Biloxi tribal lands comprise approximately 1,717 acres of Trust and Fee property.[2] The Coushatta tribe owns approximately 6,000 acres of land.[3] The Chitimacha Tribe currently has 445 acres of land held in a trust by the Federal Government, plus 500 acres of tribally owned land.[4] The amount of land owned by the Jena Band tribe is currently unclear. Louisiana also hosts 11 state-recognized tribes.[5] It is unclear if any of these tribes hold any land.



Louisiana is the only US state that does not adhere to a common law system. Instead, the state has adopted a system of civil law derived from Napoleonic Code. This means that judges are not bound by *stare decisis* and can base their ruling on their own interpretation of the law. The court structure consists of trial and appellate courts.[6] The trial courts consist of courts of general, special, and limited jurisdiction. There are 40 judicial districts within the trial court of general jurisdiction, plus a district comprising the Orleans Parish that is divided into civil and criminal district courts. The Appellate level consists of a Supreme Court and five courts of appeal. The Louisiana Supreme Court is the state's highest court.

CCUS-related activities (including production and injection operations and pipelines) are overseen by the Louisiana Department of Natural Resources (LDNR), Office of Conservation. The Office of Conservation divides its responsibilities over the Executive, Engineering Administrative, Engineering

---

[1] Bureau of Indian Affairs. Indian Lands. Data available at: https://biamaps.doi.gov/indianlands/.

[2] Tunica-Biloxi Tribe of Louisiana. History. Available at: https://www.tunicabiloxi.org/.

[3] Sovereign Nation of the Coushatta Tribe of Louisiana. A Six Point History of Our Tribe. Available at: https://www.coushattatribe.com/about.

[4] Sovereign Nation of the Chitimacha. FAQ. Available at: https://www.coushattatribe.com/about.

[5] National Conference of State Legislatures. Federal and State Recognized Tribes. Available at: https://www.ncsl.org/.

[6] Louisiana State Bar Association. Court Structure. https://www.lsba.org/Public/CourtStructure.aspx.

Regulatory, Environmental, Geological Oil and Gas, Injection and Mining, and Pipeline Divisions.[7]

CCUS Activities in the State

In August 2020, Louisiana's governor signed an Executive Order setting a state goal for net zero greenhouse gas emissions by 2050, furthering the need for CCUS development in Louisiana.[8]

Geologically, Louisiana is comprised of the Northern Louisiana Salt Basin in the North and the Louisiana Gulf Coast Basin in the South.[9] The state has both onshore and offshore fields and reservoirs that could host potential CCUS opportunities.

According to US EPA data, there are approximately 3,500 Class II injection wells in Louisiana, including 2,631 wastewater disposal wells, 461 EOR wells, and 492 Class II wells used for other purposes.[10] There are currently 29,857 producing oil and gas wells in Louisiana.[11] According to the LDNR, total oil production in Louisiana for 2020 was 29,010,860 barrels (excluding the outer continental shelf), and total gas production in 2020 was 3,037,135,647 mcf (thousand cubic feet, excluding the outer continental shelf and casinghead gas).[12]

In 2018, CO_2 emissions for Louisiana totaled 199.3 million metric tons of CO_2 including 13.2 million metric tons from coal, 88.5 million metric tons from petroleum, and 97.6 million metric tons from gas.[13]

DOE estimates that a total of between 162.78 billion and 2.102 trillion metric tons of CO_2 storage capacity are available in Louisiana. This includes 3.12 to 8.29 billion metric tons in oil and gas reservoirs, between 8.30 and 18.91 billion metric tons in unmineable coal storage, and between 151.36 billion and 2.075 trillion metric tons in saline formations.[14]

Louisiana has an extensive critical energy infrastructure, including existing LNG pipeline infrastructure, which provides opportunities for linking CO_2 sources and storage reservoirs.[15] However, it is unclear whether these pipelines can be or are available for use for CO_2 transportation. But the co-location of refineries and CO_2 sinks may limit the need for an extensive CO_2 pipeline infrastructure buildout.

Current research into CCUS focuses on storage in the State's "industrial corridor," where there are a large number of industrial CO_2 sources.[16] This area has a concentration of power plants and petrochemical facilities that generate large volumes of CO_2.[17] Injection formations of interest are

---

[7] LDNR. Office of Conservation – Divisions. Available at: http://www.dnr.louisiana.gov/.

[8] Developing CCUS Projects in Louisiana and the Gulf Coast - Global CCS Institute. Available at: https://www.globalccsinstitute.com/.

[9] Opportunities for Producing the "Stranded" Hydrocarbon Resources of Louisiana. Advanced Resources International. Available at: https://www.lsu.edu/.

[10] EPA. UIC injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.

[11] Enverus DrillingInfo. Available at: Data available at https://www.enverus.com/.

[12] LDNR. Production well data. Available at: http://www.dnr.louisiana.gov.

[13] US Energy Information Association. State Carbon Dioxide Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.

[14] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[15] LSU Center for Energy Studies. Integrated Carbon Capture, Utilization, and Storage in the Louisiana chemical corridor. Available at: https://www.lsu.eduf.

[16] Ibid.

[17] C. J. John, B. J. Harder, B. L. Jones, R. J. Bourgeois, and W. Schulingkamp. Potential for Carbon Dioxide Sequestration in Five Fields along the Mississippi River Industrial Corridor in Louisiana.

predominately depleted oil and gas reservoirs in the south and salt domes in the north.[18] Following institution of the federal 45Q tax credit, an increasing number of companies in the oil and gas, utility, petrochemical, and other industries have expressed interest in constructing and operating Class VI injection wells at new and existing sites in Louisiana.[19]

There are 64 facilities, representing 78% of Louisiana's CO_2 emissions, that qualify for 45Q tax credit.[20] According to a study of certain facilities conducted by the Rhodium Group, Louisiana has 3 gas processing facilities, 11 hydrogen facilities, 9 refineries, 2 coal plants and 7 gas plants with the combined potential to capture 40 million metric tons of CO_2 per year.[21] Additional sources of CO_2 in the state include pulp and paper plants and ammonia facilities.[22] Examples of planned CCUS projects in the state include:

- Lake Charles Methanol, a proposed gasification facility in Louisiana, planning to capture over 4 million tons per annum of CO_2 from synthetic gas (syngas). The captured CO_2 would be injected into deep saline aquifers for permanent storage. The project is slated for operations to begin in 2025.[23]
- Gulf Coast Sequestration has submitted an application to inject into an underground reservoir between Lake Charles and the Sabine River for sequestration. The reservoir is estimated to have capacity to hold 80 million metric tons of CO_2 with capacity to inject 2.7 million metric tons annually.[24]

Classification of CO_2: Commodity and Pollutant

The Louisiana Geologic Sequestration of Carbon Dioxide Act of 2009 directly addresses CO_2 as a greenhouse gas and as a commodity. Section 1102 states that "the geologic storage of carbon dioxide will benefit the citizens of the state and the state's environment by reducing greenhouse gas emissions." and that "carbon dioxide is a valuable commodity to the citizens of the state."[25] The Act also establishes a Carbon Dioxide Geologic Storage trust fund, which can be used for site inspecting, testing and monitoring, including remaining surface facilities and wells; remediation and repair of mechanical problems; or well plugging and abandonment (or conversion as an observational well).[26]

Additionally, Louisiana statute grants the State Mineral and Energy Board the authority to "explore for and develop" the mineral resources of lands belonging to the State. In doing so, they are also granted the authority to enter into operating agreements giving the state a share of revenues from the storage of oil, natural gas, liquid or liquefied hydrocarbons, or CO_2, if the storage and distribution of CO_2 is for secondary or tertiary recovery operations. [27]

---

[18] C. J. John, B. J. Harder, B. L. Jones, R. J. Bourgeois, and W. Schulingkamp. Potential for Carbon Dioxide Sequestration in Five Fields along the Mississippi River Industrial Corridor in Louisiana.
[19] LDNR. Notice of Intent. Available at: http://www.dnr.louisiana.gov/.
[20] Great Plains Institute. Louisiana. Available at: https://www.betterenergy.org/.
[21] Great Plains Institute. Jobs and Economic Impact of Carbon Capture Deployment Louisiana. Available at: https://www.betterenergy.org/.
[22] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.
[23] Global CCS Institute. Facilities. Available at: https://www.globalccsinstitute.com/co2re/.
[24] S&P Global Platts. US Company hopes to build underground CO_2 storage facility in Louisiana. Available at: https://www.spglobal.com/.
[25] RS 30:1102 (a).
[26] RS 30:1110 (a),(e).
[27] RS 30:209 (e).

The Louisiana Department of Revenue (DR) oversees severance taxes on oil, minerals, gas, and natural gas in the state. According to the DR, CO_2 is not explicitly mentioned as a type or gas or mineral, but it is possible that the DR includes it in its description of "other natural gas liquids," which are taxed at a rate per cubic feet.[28] State statute does allow a 50% tax reduction on projects that use anthropogenic CO_2 – but only for tertiary recovery projects.[29]

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

The government of Louisiana has prioritized advancement of CCUS and the development of a carbon management economy.[30] Louisiana was one of the first states to assume liability for sequestered CO_2 post site-closure.[31] Louisiana has an extensive regulatory structure that addresses all aspects of CCUS.

Pipeline Regulations

Pipelines are regulated by the Pipeline Division of the Department of Natural Resources, Office of Conservation. Specifically, the Pipeline Division regulates the use, end-use, conservation, and transportation facilities for movement of intrastate natural gas, CO_2, and compressed natural gas. The division is also responsible for pipeline safety inspections and enforcement for intrastate natural gas and hazardous liquids pipelines, as well as damage prevention enforcement on pipeline right of ways. The Pipeline Division currently regulates over 400 different intrastate pipeline operators.[32]

CO_2 pipelines are regulated under authority of the Natural Resources and Energy Act of 1973. Regulations can be found in the Louisiana Administrative Code (LAC) Title 43 Part 11 and include stipulations for transmission, transportation, accident reporting, design, construction, hydrostatic testing, operation, and maintenance.[33] Regulations specific to transportation of natural and other gas by pipeline are outlined in LAC 43 Part 13 subparts 2, 3, and 4 which directly reference 49 CFR Parts 191, 192, and 193.[34]

Laws and Regulations for CO_2 Storage

As described above, Louisiana's Geologic Sequestration of Carbon Dioxide Act of 2009 promotes geologic storage of CO_2 and establishes a state CO_2 Geologic Storage trust fund to be funded by fees paid by operators. Following completion of injection operations, both liability for and ownership of the remaining project, including the stored CO_2, transfers to the state. Regulation of CO_2 injection for storage in the state will be delegated to LDNR. While LDNR currently does not have authority to regulate Class VI wells, Louisiana has begun the application process to receive Class VI primary enforcement authority (primacy) from EPA.[35] The Office of Conservation released a notice of intent in 2020 to apply to EPA for Class VI primacy.

LDNR's notice of intent to apply for Class VI primacy includes draft rules for Class VI wells with requirements that are similar to the federal Class VI Rule and include requirements for area of review delineation, permitting, well construction and completion, corrective action, logging, sampling and testing, mechanical integrity, plugging, monitoring, reporting, financial responsibility, post-injection site

---

[28] Louisiana Department of Revenue. Gas. Available at: https://revenue.louisiana.gov/.
[29] RS 47:633.4 (b).
[30] Global CCS Institute. Developing CCUS Projects in Louisiana and the Gulf Coast. Available at: https://www.globalccsinstitute.com/co2re/.
[31] Ibid.
[32] LDNR. Pipeline Division. Available at: http://www.dnr.louisiana.gov.
[33] LAC 43-11.
[34] LAC 43-13.
[35] EPA. Primary Enforcement Authority for the Underground Injection Control Program.

care, site closure, well emergency and remedial response.[36] The draft rules do not contain reference to induced seismicity or unitization. Pending primacy approval, any Class VI wells in Louisiana are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 6.

Regulation of Oil and Gas Production

LDNR oil and gas regulations are promulgated under the authority of Title 43 of the Louisiana Administrative Code.[37] Multiple divisions of LDNR have various responsibilities regarding implementation of regulations for oil and gas production; the primary divisions in charge of oil and gas regulation are the Geological Oil and Gas Division and the Engineering Division.[38]

The Geological Oil and Gas Division administers a regulatory program to prevent waste of oil and gas, to conserve the natural resources of the State, to prevent the drilling of unnecessary wells, and to protect the correlative rights of mineral owners through the application of state laws, rules, regulations, and policies of the Office of Conservation.[39]

The Engineering Division implements rules and regulations outlined in LAC 43: XIX Subpart 1 concerning the construction, maintenance, and closure of oilfield pits, plugging of oil and gas wells, and the inspection of well sites. The Environmental Division implements the regulations included in the Exploration and Production Waste Program for off-site management of E&P waste.[40]

Under R.S. Title 30, LDNR has the authority to compel unitization for deep pools if there is sufficient evidence that it is economically feasible, the geologic top of the pool encounters the well at a depth of greater than 15,000 feet, and that unitization is reasonably necessary for promotion of pool development. R.S. Title 30 equates waters produced incidental to oil or gas exploration or production as geothermal resources and regulates them as such.[41] Our research did not identify anything related to unitization of shallow pools.

Louisiana has separate spacing rules for deep oil and gas wells. Oil wells drilled deeper than 3,000 feet may not be located closer than 330 feet from any property line or 900 feet from any other well completed or permitted to produce in the same pool. No gas well may be located within 330 feet of a property line or within 2,000 feet of other wells in the same pool.[42] Shallow oil wells are not subject to spacing requirements.

A permit must be obtained before drilling can begin for any well or test well drilled with the purpose of mineral search or exploration.[43] A permit application to drill a production well must be submitted to LDNR, and must include information about the well’s location and financial security in an amount based on the depth of the well.[44] There are no specific requirements for the content of the permit application, and the permit application form, MD-10-R, requires only basic information about the well. There are no public notice or hearing provisions in the oil and gas regulations.

---

[36] LDNR. Notice of Intent. Available at: http://www.dnr.louisiana.gov/.
[37] LAC 43-19.
[38] LDNR. Office of Conservation – Divisions. Available at: http://www.dnr.louisiana.gov/.
[39] Ibid.
[40] Ibid.
[41] RS 30:4.
[42] LAC 43-19 §1901.
[43] LAC 43-19.
[44] LAC 43-19 §103, 104.

Regulation of Injection Activities

The UIC Section of LDNR is responsible for administration, permitting, inspection, and enforcement of activities pertaining to the protection of USDWs. LDNR currently has primacy for Class I-V wells, and all injection activities are regulated under the State's UIC program by the Injection and Mining Division.[45]

Permits are required for all Class II injection wells[46] and there are different application requirements for new and existing enhanced oil recovery projects. Title 43 Part 19 contains requirements for permit applications for enhanced oil recovery wells. Applications must include operator information, map of the AoR, as well as lease information, injection formation description, logs, casing, plan for development, and a well schematic.[47]

LDNR may also allow pilot projects for enhanced recovery for a period of six months from the date of initiation of injection. Operators are required to apply for pilot projects using Form UIC-2 EOR for each well intended for injection and provide information the Commissioner deems necessary to justify the approval of the pilot project.[48]

Class II permits are subject to public notice in the official state journal and a public hearing. Notice requirements for commercial saltwater facilities can be found in LAC 43:XIX, Chapter 5.[49]

Environmental Laws

The Louisiana Air Control Law assigns the Department of Environmental Quality to regulate the discharge of contaminants into the air resources of the state. The statute does not list CO_2 or methane directly, but it does define "air contaminant" as any non-naturally produced particulate matter, dust, fumes, gas, mist, smoke, or vapor.[50] However, they limit the definition of "toxic air pollutant" to those that cause adverse effects in humans.[51] The Department of Environmental Quality is tasked with compiling and maintaining an air emissions inventory. Permits, licenses, variances, or compliance schedules for all sources of air contaminants are required in the State of Louisiana, and when the Secretary deems it advisable.[52]

The definition of a USDW in the state's UIC regulations is consistent with the Code of Federal Regulations (40 CFR 144.3). Fresh water and USDWs are not defined in the context of the production well regulations. Our research did not identify any requirements or guidelines related to induced seismicity in Louisiana.

Industrial Siting Requirements

In Louisiana, a well that is to be drilled to 10,000 feet or more may not be located within 500 feet of commercial or residential structures not owned by the applicant, his lessor, or other predecessor in interest unless given written consent by those owners.[53]

---

45 56 FR 41072, Aug. 19, 1991, as amended at 62 FR 1834, Jan. 14, 1997.
46 LAC 43-19-1-5.
47 Ibid.
48 LAC 43-19-1-5.
49 Ibid.
50 RS 30 §2053 (1).
51 RS 30 §2053. (3).
52 §2054.(21).
53 LDNR. Permit to Drill Applications. Available at: http://www.dnr.louisiana.gov/.

Eminent Domain

Private ownership rights in Louisiana are established in the state constitution. Under Article 1, Section 4, private property is not to be taken or damaged by the state unless it is for "public purposes," which explicitly includes public utilities for the benefit of the general public.[54] Private property taken or damaged by private entities, similarly, must not be taken unless it is for a "public and necessary purpose," although the Constitution leaves the decision of whether the purpose is public and necessary for the judiciary.[55] In both cases, "just compensation" must also be paid to the property owner.

The procedure for establishing eminent domain begins once the condemner files a petition in the district court where the property is being expropriated. The petition will contain a statement of the purpose for the property being expropriated and why it is necessary. Expropriation cases are tried in a court without a jury unless the plaintiff requests in the petition or unless the plaintiff and defendant dispute the proper amount of compensation.[56]

Prior to filing an expropriation suit, the condemner must offer to compensate the owner an amount equal to either the lowest appraisal or evaluation.[57] The basis of assessment should include the property value from before the contemplated improvement was proposed, as well as damages to the defendant because of the expropriation.[58] If the private property owner disagrees with the amount of compensation, they have the right to a trial by jury to determine the property amount.[59] However, corporations engaged in the "piping or marketing of carbon dioxide for use with a secondary or tertiary recovery project for the enhanced recovery of liquid or gaseous hydrocarbons," and corporations engaged in the injection of CO_2 for the underground storage of CO_2, have the authority to expropriate needed property even if they are unable to reach an agreement with the owner over compensation.[60]

Property in Louisiana can also be expropriated for the underground storage of CO_2 in storage facility projects in the state.[61] This includes surface and subsurface rights, mineral rights, and other property interests necessary or useful "for the purpose of constructing, operating, or modifying a carbon dioxide storage facility or transporting carbon dioxide by pipeline to such storage facility."[62] This rule, however, does not grant expropriation of the mineral rights or other property rights associated with the approvals required for injection of CO_2 into enhanced recovery projects.

For the underground storage of CO_2 in particular, Louisiana statute contains a set of overlays that must be completed to exercise the use of eminent domain.[63] The Commissioner must find that the underground reservoir used to store the CO_2 is both suitable and feasible for use, and it will not endanger lives or property, nor contaminate other formations containing fresh water, oil, gas, or other commercial mineral deposits.[64]

The Louisiana Geologic Sequestration of Carbon Dioxide Act dictates eminent domain laws for operation and transportation of CO_2 to storage facilities. Storage operators looking to exercise eminent domain and surface and subsurface rights must obtain a permit and a certificate of public convenience.[65]

---

[54] Louisiana Constitution, Article 1, Section 4 (B1).
[55] Louisiana Constitution, Article 1, Section 4 (B4).
[56] RS 19:4.
[57] RS 19:2.2 (a2).
[58] R.S. 19:9.
[59] R.S. 19:4.
[60] RS 19:2.
[61] Ibid.
[62] Ibid.
[63] RS 30:22.
[64] RS 30:22 (C1-3).
[65] RS 30:1108 (a).

They also have the right to construct or develop facilities and pipelines along, over, across, and under a navigable stream or public highway, street, bridge, or other public places – so long as traffic is not interfered with.[66]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Per Louisiana Statute, "Minerals" include oil, gas, soil, gravel, shells, subterranean water, or "other naturally occurring substances in or as a part of the soil, or geological formations on or underlying the land."[67] Ownership of land in Louisiana includes all minerals occurring in a naturally solid state,[68] but does not include ownership of oil, gas, and other minerals occurring naturally in liquid or gaseous form, or "any elements or compounds in solution, emulsion, or association with such minerals."[69] This means that, unlike in other states, landowners in Louisiana cannot own these types of minerals under their land. Instead, they only retain the right to "explore and develop" their property for the production of minerals. This is known as a "mineral servitude."[70] Ownership only begins once the minerals are reduced to possession and are under physical control that permits delivery to another.[71]

Landowners with rights in a common reservoir or deposit of solid minerals have correlative rights and duties with respect to one another in developing minerals.[72] However, they have no right against another who causes drainage of liquid or gaseous minerals from beneath the property if the drainage results from drilling or mining operations on other lands.[73] The owner of a mineral right and the landowner burdened by a mineral right must exercise their respective rights "with reasonable regard" for the other person, as must the owners of separate mineral rights in the same land.[74]

Louisiana law does not provide for the separation of mineral estates from the land. The landowner can convey, reserve, or lease the right to explore and develop land for the production of minerals, but only to create a mineral servitude, royalty, or lease. [75] Mineral rights are considered to be "real rights" but can expire and revert to the owner of the land by prescription of unuse if not used for 10 years,.[76, 77]

Government-owned land cannot strip itself of its mineral rights. Louisiana's constitution states that the mineral rights on property sold by the state are reserved unless the owner buys or redeems property sold or adjudicated to the state for taxes.[78] Additionally, "lands and mineral interests of the state, of a school board, or of a levee district shall not be lost by prescription." When the government entity acquires land without the mineral rights, conversely, prescription of the mineral right is suspended so long as the government entity holds title, and the aforementioned 10-year non-use expiration doctrine does not apply.[79] Prescription will begin again once the government entity sells the land to a non-government entity.

---

66 Ibid.
67 RS 31:4.
68 RS 31:5.
69 RS 31:6.
70 RS 31:21.
71 RS 31:7.
72 RS 31:9.
73 RS 31:14.
74 RS 31:11.
75 RS 31:15.
76 RS 31:16.
77 RS 31:27.
78 LA Const. art. IX, sec. 4a.
79 RS 31:149 (b).

Unique to Louisiana is that property taken by a government entity that decides to sell within 30 years must be offered first to the previous owner or their heir at "fair market value." If this fails to happen, the former owner has the right to petition the court to have the property declared as such.

All contracts in Louisiana are subject to the general contracts rules of Louisiana Civil Code.[80] Contracts are interpreted based on the "common intent" of the parties involved.[81] This interpretation begins with a search of the contract to determine if the words are "clear and explicit," and lead to no absurd consequences.[82] The meaning of words are interpreted according to their general meaning unless the contract involves a technical matter; in this case, the technical term will be considered.[83] If there is a doubtful provision within the contract, the interpretation should consider the nature, equity and usages of the contract, party conduct before and after contract formation, and other similar contracts between the same parties.[84, 85, 86] If the contract can be interpreted in more than one way, the courts must go with the interpretation that favors the party who did not draft it.[87]

Our research did not find any discussion of whether CO_2 was included in a grant of minerals. As previously mentioned, however, the Louisiana Geologic Sequestration of Carbon Dioxide Act specifies that ownership of injected CO_2 lies with the property of the party that owns the CO_2, and "in no event" will it ever be subject to the right of the surface owner of the mineral interest owner.

Split Estates

As mentioned above, Louisiana law does not permit the separation of a mineral estate distinct from the full title to the land. Instead, landowners can create a "mineral servitude," which Louisiana Statute defines as a "right of enjoyment of land belonging to another for the purpose of exploring for and producing minerals and reducing them to possession and ownership."[88] If the mineral servitude is not used within 10 years from the date of its creation, it will expire and return to the landowner.

Generally, mineral servitude owners have a right to "reasonable use" of the surface in order to explore and produce minerals.[89] However, operators must give at least 30 days' notice to the surface owners before entering the land to drill.[90] This does not include pre-drilling activities, nor does it include circumstances in which the operator already has an existing contract with the surface owner or an existing well on the property.

Pore Space Ownership

Aside from its eminent domain laws discussed above, Louisiana has not yet specifically addressed pore space ownership. However, past court opinions have supported the surface owner's right to the pore space beneath the property. In *United States v. 43.42 Acres of Land*, the court stated that "minerals, in their natural state, cannot be "owned" separately from the land…..whether a state is

---

[80] Proeducate. Contracts and Leases – General Contract Law (Louisiana).
[81] CC 2045.
[82] CC 2046.
[83] CC 2047.
[84] "Equity," as defined in CC 2055, is based on the principles that no one is allowed to take unfair advantage of another and that no one is allowed to enrich himself unjustly at the expense of another.
[85] "Usage," as defined in CC 2055, is a practice regularly observed in affairs of a nature identical or similar to the object of a contract subject to interpretation.
[86] CC 2053.
[87] CC 2056.
[88] RS 31:21.
[89] RS 31:23
[90] RS 31:23

governed by an "ownership" or a "non-ownership" theory of mineral rights, the mineral owner cannot be considered to have ownership of the subsurface strata containing the spaces where the minerals are found."[91] In *Southern Natural Gas Company v. Sutton*, similarly, the Court of Appeals stated that "surface ownership, however, includes the right to use the reservoir underlying…for storage purposes."[92] According to a paper from Reed Smith LLP, this holding is consistent with the reasoning of federal cases decided under Louisiana law, which have consistently held that the surface owner owns the rights to subsurface storage.[93]

Water Rights

Water rights in Louisiana are regulated by the Louisiana Department of Environmental Quality and the Department of Natural Resources. Under Civil Code, running water and the water of natural navigable water bodies are classified as "public things" owned by the state.[94] "Public things" are subject to public use in accordance with applicable laws and regulations, provided the user does not cause injury to the property of adjoining users.[95]

Article 658 of the Civil Code states that "the owner of an estate through which water runs, whether it originates there or passes from lands above, may make use of it while it runs over his lands…he cannot stop it or give it another direction and is bound to return it to its ordinary channel where it leaves his estate."[96] It seems, therefore, that Louisiana adheres to a Riparian Rights System.

According to the Annual Institute on Mineral law, groundwater is considered to be a fugacious mineral that, like oil and gas, is "res nullius" until it is reduced to possession and ownership.[97] This analogy between groundwater and oil, according to the article, dates back to the early 1900s and is found in the few Louisiana decisions that mention, in dictum, the nature of groundwater.

Lithium Ownership and Extraction

No information was identified about mines that produce lithium or extensive lithium deposits in Louisiana, and our research did not identify any Louisiana state laws or regulations that address lithium extraction or mining.

---

[91] *United States v. 43.42 Acres of Land*, 520 F. Supp. 1042 (W.D. La. 1981).
[92] Southern Natural Gas Co. v. Sutton, 406 So. 2d 669 (La. Ct. App. 1981).
[93] Stefanie L. Burt. Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions.
[94] CC 450.
[95] Ibid.
[96] CC 658.
[97] Duarte, Nicole M. (2010) "Subsurface Water Rights in Louisiana," Annual Institute on Mineral Law: Vol. 57, Article 16. Available at: http://digitalcommons.law.lsu.edu/mli_proceedings/vol57/iss1/16.

MICHIGAN

Executive Summary

The primary area targeted for CO_2 storage in Michigan is the Niagaran Pinnacle Reef Trend in the western part of the state. Michigan considers CO_2 to be both a commodity (by virtue of a tax levied on oil and gas activities) and a pollutant (which the state is working to reduce emissions to the atmosphere). Michigan also specifically grants eminent domain for transportation of oil, petroleum, and CO_2.

Background

Michigan includes federal, state, tribal and fee land. The state spans 36,492,160 acres, of which 3,637,599 (or 10%) are owned by the federal government.[1] There are also 12 federally-recognized tribes, but no state-recognized tribes.[2] There are currently 5 tribal reservations located throughout the state: the Isabella Reservation, which spans 2,373 acres in one location and 96 acres in another; the L'Anse Reservation, which spans 1,029 acres in one location and 47,216 in the other, and the Ontonagon Reservation, which spans 2,561 acres.[3]

Michigan's law system operates under common law. Court cases begin in the local courts, which consist of 57 circuit courts, 78 probate courts, and 100 district/municipal courts, small claims courts, and courts of claims.[4] Generally, a person who loses in the lower courts may appeal to the Michigan Court of Appeals. The 24 judges in the Court of Appeals sit state-wide (but are elected or appointed from 1 of 4 districts).[5] Decisions made by the Court of Appeals may be appealed by "leave application" to the Michigan Supreme Court, which is the highest court in the state and consists of 6 justices and 1 Chief Justice.

As a result of Michigan Court Rule 2.615, the state also allows Indian tribal court judgments to be enforced.[6] According to the state court's website, any tribal court judgement resulting from an existing reciprocal ordinance, court rule, or "binding measure" (that has been transmitted to the State Court Administrative Office) will be recognized as enforceable.

CCUS-related activities in Michigan are regulated by the Oil, Gas, and Minerals Division (OGMD) of the Michigan Department of Environment, Great Lakes, and Energy (EGLE).[7] Following the Flint water crisis, Governor Whitmer reorganized the structure of the Department of Environmental Quality (DEQ) so that it could respond more quickly to water quality issues. As part of this

[1] Federal Land Ownership: Overview and Data (2020). *Congressional Research Service.*

[2] Federal and State Recognized Tribes (2020). *National Conference of State Legislatures.* Accessible at https://www.ncsl.org/legislators-staff/legislators/quad-caucus/list-of-federal-and-state-recognized-tribes.aspx#State.

[3] Michigan Indian Reservations. Accessible at https://native-americans.com/michigan-indian-reservations/.

[4] Michigan's Current Court System. (2021). *Michigan Courts.* Accessible at https://courts.michigan.gov/education/learning-center/Pages/hidden/Michigan's-Current-Court-System.aspx.

[5] Ibid.

[6] Native American Tribal Courts. (2021). *Michigan Courts.* Accessible at https://courts.michigan.gov/courts/tribalcourts/pages/default.aspx.

[7] EGLE. Oil and Gas. Available at https://www.michigan.gov/.

reorganization, the name was changed to EGLE. For the remainder of this chapter, EGLE, formerly known as the DEQ, refers to Michigan's environmental agency charged with permitting and regulatory authority.

CCUS Activities in the State

Michigan's oil and natural gas production industry began in 1925 when the Saginaw Prospecting Company drilled a test well and found that there was enough oil to be commercially profitable. This development attracted other companies and led to the discovery of multiple other fields throughout the 1920's. The largest of these was the Mt. Pleasant field underneath Isabella and Midland Counties in the central part of the state.[8]

Approximately 60,000 oil and gas related wells have been drilled within Michigan.[9] There are approximately 1,250 active Class II injection wells in Michigan, primarily used for brine disposal and enhanced recovery.[10]

According to the U.S Energy Information Association, total oil production for 2020 was 4.1 million barrels,[11] and total gas production in 2019 was 83,733 mmcf (million cubic feet).[12] Annual oil production has averaged about 6.3 million barrels over the last 20 years.[13]

Although several formations have contributed to Michigan's oil production, production from the Niagaran Reef, along the northern flank of the Michigan Basin, accounts for almost half of the total oil produced in Michigan. It is now a target for EOR activities.[14] The northern reef trend extends into Michigan from the middle of the western border in two prongs, one to the northeastern side of the state, and the other to the southeastern side.[15] In the 1960's there was a major push towards Niagaran Reef exploration, with large scale gas companies launching huge lease plays in the Northern Reef Trend.[16]

In 2018, about 68% of Michigan's CO_2 emissions were generated in the electric power and transportation sectors, specifically gas processing plants and ethanol facilities.[17,18] Michigan's capacity to store CO_2 has been estimated to be between 31.72 and 66.52 billion metric tons. Saline formations account for the bulk of this amount, with an estimated capacity between 31.55 and 66.20 billion metric tons, followed by oil and natural gas reservoirs (0.17 to 0.32 billion metric tons).[19] The Mt. Simon Sandstone, a deep saline reservoir ranging up to 1,300 feet in thickness, has an estimated storage capacity of more than 29 billion metric tons throughout parts of Michigan, Illinois, Indiana, Kentucky, Michigan,

---

[8] Oil Gas Michigan. History of Oil and Gas Industry in Michigan. Available at: https://oilgasmichigan.com/history/
[9] EGLE. Oil and Gas. Available at: https://www.michigan.gov/.
[10] EGLE. Oil and Gas. Available at: https://www.michigan.gov/.
[11] US Energy Information Association. Michigan Crude Oil Production. Available at: https://www.eia.gov.
[12] US Energy Information Association. Michigan Natural Gas Gross Withdrawals and Production. Available at: https://www.eia.gov.
[13] Ibid.
[14] Eno Petroleum Corporation. History of Oil in Michigan. Available at: https://www.enopetroleum.com/HistoryofOilinMichigan.html.
[15] U.S. DOE. Michigan Basin Project.
[16] Eno Petroleum Corporation. History of Oil in Michigan. Available at: https://www.enopetroleum.com/HistoryofOilinMichigan.html.
[17] US Energy Information Association. State Energy Data System.
[18] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.
[19] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

and Ohio.[20] The primary area targeted for CO_2 storage in Michigan is the Niagaran Pinnacle Reef Trend.[21] The target formations in the Niagaran Pinnacle Reef Trend are oil-bearing Silurian dolomite and limestone.[22] These formations are located at depths between 4,000 and 6,000 feet.[23]

According to the Global Carbon Capture and Sequestration Institute, there are two major CCUS projects proposed or completed in Michigan. Since 2003, Core Energy has been operating a CO_2-EOR program in Otsego County, Michigan. CO_2 for injection is sourced from a gas processing facility that removes CO_2 produced from the Antrim shale gas fields. Core Energy has reported that as of 2016, operations have injected more than 2 million tons of CO_2 into the Northern Pinnacle Reef Trend.[24] The 11-mile CO_2 transmission pipeline for this project is the only major CO_2 transport pipeline in the state.[25]

Additionally, the Midwest Regional Carbon Sequestration Partnership (MRCSP) conducted a small-scale CO_2 injection test within the Northern Pinnacle Reef Trend, beginning monitoring operations in 2013. Since then, the operation has stored more than 330,000 metric tons of CO_2.[26]

Classification of CO_2: Commodity and Pollutant

Michigan considers CO_2 to be both a commodity (by virtue of a tax levied on oil and gas activities) and a pollutant (for which the state is working to reduce emissions to the atmosphere).

Michigan's Severance Tax Act levies a tax on oil[27] and gas[28] severed from the soil in Michigan, at a tax rate of 5% of the gross market value for gas and 6.6% for oil.[29] However, Section 205.303 grants a reduced severance tax rate to approved EOR projects using CO_2 injection, equal to 4.0% of the gross market value for oil and gas.[30]

Additionally, Michigan statute 460.1047 allows electric providers to recover the costs of constructing and maintaining "advanced cleaner energy systems," which include coal-fired plants if either 85% or more CO_2 emissions are to be captured for geologic sequestration or if they are used for commercial/industrial purposes that do not result in CO_2 being released into the atmosphere.[31]

In 2019, Gov. Whitmer signed an Executive Order joining the United States Climate Alliance, which is a coalition of governors "devoted to pursuing the goals of the internationally accepted Paris Agreement." Executive Directive 2019-12 directed the state of Michigan to implement a series of policies aimed at reducing carbon pollution, promoting clean energy deployment, and achieving a 28% reduction in greenhouse gas emissions below 1990 levels by 2025.[32] The following year, Governor Whitmer signed two additional executive orders that, when combined, create the "MI Healthy Climate Plan." Under these orders, Governor Whitmer established the goal of economic decarbonization in Michigan by 2050. The

[20] David Barnes et al. Geological Sequestration of Carbon Dioxide in the Cambrian Mount Simon Sandstone: Regional Storage Capacity Site Characterization and Large-scale Injection Feasibility, Michigan Basin.
[21] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[22] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[23] Ibid.
[24] Global CCS Institute. Facilities — CO_2RE. Available at: https://www.globalccsinstitute.com/co2re/.
[25] U.S. DOE. A Review of the CO_2 Pipeline Infrastructure in the U.S. Available at: https://www.energy.gov/.
[26] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[27] The word "oil" means petroleum oil, mineral oil, or other oil taken from the Earth, according to 205.311.
[28] The word "gas" does not include methane gas extracted from a landfill, according to 205.311.
[29] Mich. Comp. L. Ann. § 205.301.
[30] Mich. Comp. L. Ann. § 205.303.
[31] Mich. Comp. L. Ann. § 460.1047 (7iii)
[32] Executive Directive 2019 – 12 (2019). The Office of Gretchen Whitmer.

orders also created an advisory council within EGLE, known as the Council on Climate Solutions, to oversee the development and implementation of the Plan.[33]

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

Oil and gas production activities and pipelines in Michigan are regulated by various divisions of EGLE.[34] All injection activities, including CO_2 injection via a Class II or Class VI well, are regulated by US EPA Region 5.

Pipeline Regulations

Since 2014, the Michigan Public Service Commission (MPSC) under EGLE has permitting authority over CO_2 transmission pipelines, under the Michigan Crude Oil and Petroleum Act 16 of 1929 (Act 16).[35, 36] However, CO_2 streams that are captured and transported for the purposes of injection are excluded from the Hazardous Waste Management Rules.[37] The rules state that transportation of a CO_2 stream must comply with US DOT requirements, including pipeline safety laws under 49 USC 60101 to 60141; pipeline safety regulations under 49 CFR parts 190 to 199; and pipeline safety regulations adopted and administered by a state authority under a certification under 49 USC 60105, as applicable. According to a report by the Michigan Agency for Energy in cooperation with MPSC, as of 2017, MPSC had not received any applications for the construction of CO_2 transportation pipelines.[38]

Laws and Regulations for CO_2 Storage

Michigan has not applied for or been granted Class VI program primacy by EPA; therefore, any Class VI wells in Michigan are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 5. The only treatment of CO_2 storage in Michigan regulations is the offering of financial incentives for CCUS and a reduced severance tax rate for approved EOR projects using CO_2 injection, as described under "Classification of CO_2: Commodity and Pollutant" above.

Regulation of Oil and Gas Production

The Oil, Gas, and Minerals Division (OGMD) of EGLE is tasked with administering the statute and rules subject to Part 615, Supervisor of Wells, for issuance of oil and gas well permits.[39] Oil and gas activities included under the regulatory oversight of OGMD include permitting, drilling, operating, plugging, and inspecting active well sites and production facilities.[40]

Part 615, Supervisor of Wells, of Michigan's Rules and Regulations govern the siting, area of review requirements, construction, operation, monitoring and reporting, and plugging of wells associated with oil and gas exploration and production in the state. While the regulations do not describe the content of a permit application, EGLE-OGMD's website describes the process of obtaining an oil and gas drilling

---

[33] Executive Directive 2020-182. (2020). The Office of Gretchen Whitmer. Accessible at https://www.michigan.gov/whitmer/0,9309,7-387-90499_90705-540277--,00.html.

[34] EGLE. Oil and Gas. Available at https://www.michigan.gov/.

[35] Report to the Legislature: Review of Policies Relating to Carbon Dioxide Capture from Industrial Sources and the Use and Sequestration of Captured Carbon Dioxide in Enhanced Oil Recovery. Available at https://www.michigan.gov/

[36] 1 MCL 483.1 et seq. Available at http://legislature.mi.gov/doc.aspx?mcl-Act-16-of-1929. See also filing requirements under MPSC's Rules of Practice and Procedure Before the Commission, pp. 45-68 available on the MPSC website.

[37] Mich. Admin. Code. r. 299.9204, Subrule 12(a).

[38] Report to the Legislature: Review of Policies Relating to Carbon Dioxide Capture from Industrial Sources and the Use and Sequestration of Captured Carbon Dioxide in Enhanced Oil Recovery. Available at https://www.michigan.gov/.

[39] Under authority of the Natural Resources and Environmental Protection Act, 1994, PA 451, as amended.

[40] EGLE. Division Guide. Available at https://www.michigan.gov/.

permit. In addition to the permit application, a prospective operator must submit an application fee, bond, and required forms and notifications (including a survey record, supplemental plat, environmental impact assessment, soil erosion and sedimentation control plan, wellhead blowout control systems, and copy of a letter to the surface owner). The well must also be properly spaced for its location and intended formation. The applicant must also have the necessary mineral and surface rights. After the initial permit application review by EGLE staff, the Area Geologist inspects the staked location on-site to verify the survey, environmental impact assessment, and all other aspects of the application are administratively complete and technically accurate.[41] Once an application is submitted, EGLE has 50 days to make a permit decision. Public notice must be given at least 30 days in advance of the anticipated approval date of applications and must be placed in the local newspaper upon approval.[42]

Unitization of oil and gas is regulated under Part 617.[43] Any interested lessee may submit an application to EGLE for a permit for unit operation. The EGLE can compel unitization if it finds that unitization would substantially increase the ultimate amount of production, extra production would exceed the additional costs of unit operation, and the unitization plan prevents waste and protects correlative rights.

Regulation of Injection Activities

As of August, 2021, all injection wells, including Class II wells, in Michigan are overseen by EPA Region 5. The state of Michigan applied for primacy over Class II wells pursuant to Section 1425 of the Safe Drinking Water Act (SDWA),[44] but on March 19, 2021, EPA withdrew its approval of Michigan's UIC Class II primacy application following the receipt of adverse public comments.[45]

As such, Class II wells in Michigan are dually permitted by both EGLE (under part 615 of EGLE's rules, which are the well Supervisor's regulations) and EPA.[46] Because EPA directly implements the Class II UIC Program in Michigan, any injection permits must be obtained from Region 5. In addition to meeting the federal requirements under the purview of SDWA, Michigan law includes protections and authority over surface location.[47] These protections are the same as those outlined under "Regulation of Oil and Gas Production."

While EPA Region 5 retains authority over Class II wells in Michigan, a brief summary of the proposed UIC rules as described in Michigan's primacy application is provided for reference. The draft rules stipulated that all operators must receive a Class II well permit prior to drilling, operating, or converting wells. Decisions on applications cannot be made unless a public hearing has been held. Proposed plans for location, drilling, deepening, redrilling or reopening, casing, sealing, operating, and plugging of secondary recovery wells drilled for EOR, or disposal wells for salt water, brine, or other oil field wastes, can be altered by the director of EGLE to ensure the prevention of oil or gas transmission between strata, or of water or brines into oil or gas strata.[48]

---

[41] From "Application Instructions for Oil and Gas Well" on www. https://www.michigan.gov/egle.
[42] EGLE. Oil and Gas Well Application Permits. Available at https://www.michigan.gov/.
[43] Part 617, Unitization, 1994 PA 451.
[44] EGLE. State of Michigan Underground Injection Control Program: Primacy Application to United States Environmental Protection Agency – Region 5. Available at https://www.michigan.gov/.
[45] EPA. State of Michigan, UIC Class II Program Approval - Withdrawal of the Direct Final Rule | US EPA.
[46] Ibid.
[47] Ibid.
[48] Ibid.

Environmental Laws

Although Michigan does not have regulations specifically addressing induced seismicity, public comments for multiple applications for UIC wells have addressed induced seismicity, prompting EGLE to respond. In response to comment for one Class I well, concerns regarding induced seismicity were addressed by the operator by providing a table listing the locations of magnitude 3.0-4.2 earthquakes within 200km of the proposed injection well.[49] Any Class VI injection well would be subject to the EPA requirements to provide information on seismic history and seismic sources at 40 CFR 146.82(a)(3)(v).

Michigan does not have significant production of coal bed methane,[50] and CO_2 and methane are both excluded from EGLE's definition of toxic air contaminants.[51] However, the Michigan Department of Environmental Management requires air permits or approval for sources that emit at least 100,000 tons per year of CO_2e. The same requirement is imposed on sources emitting greenhouse gases including methane.[52]

Under R 324.103(s) USDWs are defined as fresh water or mineral water within an aquifer or portion of an aquifer that either supplies a public water system or contains enough ground water to supply a public water system. This definition applies only to aquifers or portions of aquifers which either currently serve as a source of public drinking water or have fewer than 10,000 milligrams per liter total dissolved solids. These regulations, promulgated under Part 615, were adopted to correspond to the definition under the SDWA.[53]

Industrial Siting Requirements

The requirements for the siting of oil and gas wells are under the authorities discussed above, with additional detail in the context of siting provided herein. All sites submitted for application must have been surveyed by a state licensed surveyor and describe the well and bottom hole location and its distance from the nearest section, quarter section, and drilling unit lines. Applications must identify features located within 1,320 feet of the well including surface waters and other environmentally sensitive areas identified by the EGLE, including: floodplains, wetlands, natural rivers, critical dune areas, and threatened or endangered species. Applications should also identify all buildings, recorded fresh water wells and reasonably identifiable fresh-water wells, public roads, pipelines, and powerlines within 600 feet of the proposed well location, Type I and IIa public water wells within 2,000 feet, and Type IIb and III public water wells within 800 feet.[54]

Applications must show that drilling units for wells should be 40 acres or a quarter-quarter section. The producing area of the well may not be located within 330 feet of the drilling unit boundary and 50 feet from drilling mud pits.

Eminent Domain

Eminent Domain law is addressed in Article X § 2 of Michigan's Constitution. Private property cannot be taken for condemnation without "just compensation," which the state defines as at least 125% of the fair market value of the property in question.[55] It is up to the condemner to prove that taking the property is for "public use;" however, the state Constitution specifies that the term cannot be used to

[49] EGLE. Oil, Gas, and Minerals Division response to comments Michigan Potash.

[50] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[51] EGLE. Michigan Guide to Environmental Health, and Safety Regulations. Available at https://www.michigan.gov/.

[52] EGLE. Michigan Guide to Environmental Health, and Safety Regulations. Available at https://www.michigan.gov/.

[53] EGLE. State of Michigan Underground Injection Control Program: Primacy Application to United States Environmental Protection Agency – Region 5. Available at https://www.michigan.gov/.

[54] Part 615, Administrative Rules, 1994 PA 451.

[55] Mich. Cons. Article X § 2.

include transfer to a private entity for the purposes of "economic development" or the enhancement of tax revenues.[56]

Under current statute, the federal and state governments, their respective agencies, cities with a population of 25,000 or more, and public corporations all have the authority to exercise eminent domain.[57] Additionally, anyone engaged in the transportation of oil, petroleum, or CO_2 substances, as well as anyone constructing and operating pipelines for those substances, are granted the right of condemnation through eminent domain and the use of highways to acquire rights-of-way under Authority of Act 16.[58] In doing so, pipeline companies must make a "good faith effort" to minimize the physical impact and the economic damage resulting from constructing or repairing a pipeline.[59] These pipelines are declared common carriers under Michigan law.[60]

The condemnation procedure for the exercise of eminent domain is laid out under the Uniform Condemnation Procedures Act. To acquire property, the condemner must first commence a condemnation action.[61, 62] When negotiating the purchase price, the condemner must submit a written good faith offer to the owner, establishing the amount that they have determined to be "just compensation" based on their appraisal.[63] If they are unable to agree with the owner over the amount, however, they may file a complaint with the circuit court in the location of the property for its acquisition, in which the courts will determine the proper compensation amount.[64] In the event that only a portion of property is taken but its acquisition would destroy the remaining property, the condemner must pay for the entire parcel.[65]

Additionally, the condemner must provide written notice if acquisition of the property may necessitate relocation on the owner's behalf.[66] The notice must also note that the occupants may not be displaced until either moving expenses or a moving allowance is paid, and that the residents have 180 days after the payment is made to relocate to a "comparable replacement dwelling."[67] The exception is if the condemner is complying with applicable federal regulations and procedures regarding payment of compensation or relocation requirements, in which those regulations and procedures take precedence.[68]

For pipeline corporations and operators specifically, eminent domain cannot be exercised until they file an "explicit authorized acceptance" of Act 16 with the Michigan Public Utilities Commission, along with a plat detailing the location and capacity of "all pumping stations, gate valves, check valves and connections and appliances of all kinds used, or to be used, on said trunk line or lines."[69]

---

[56] Ibid.
[57] MCL 213.1; MCL 213.23; and MCL 213.111.
[58] MCL 483.2.
[59] MCL 483.2b.
[60] MCL 483.3; MCL 483.5.
[61] MCL 213.52 (2).
[62] If the condemner is a private agency, they may need to secure a "certificate of public necessity" from the MPSC beforehand, per MCL 213.52 (3).
[63] MCL 213.55 (1).
[64] MCL 213.55 (2).
[65] MCL 213.54 (1).
[66] MCL 213.55 (1).
[67] MCL 213.59(7a).
[68] MCL 213.59(7b).
[69] MCL 483.6.

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Mineral rights in Michigan are considered a type of real property that can be owned alongside with, or separately from, the surface rights.[70] If unsevered, the surface owner of the land has an "undivided interest" in all oil, gas, and minerals beneath their land.[71] Severance of the mineral rights from the surface is conveyed through a deed listing the mineral rights as a reservation or an exception, or as a conveyance transferring the mineral rights.[72] In either case, both the mineral and the surface rights become freehold estates in fee simple, unless there are multiple mineral right holders, in which their interests are held as tenants in common.[73, 74]

Mineral contract disputes are generally resolved with a review of the language to determine the parties' intent at the time the agreement was formed.[75] If the language in the contract is inconsistent or can result in multiple interpretations, it will be declared "ambiguous," and typically will be construed against the drafting party.[76] The courts also allow extrinsic evidence to determine intent if necessary.[77] The term "mineral" itself has not been defined statutorily, and has different meanings depending on the context.[78, 79] The term "mineral right," however, was defined in *Department of Transportation v. Goike* by the Michigan Court of Appeals, who declared that it is, "[a]n interest in minerals in land, with or without ownership of the surface of the land. A right to take minerals or a right to receive a royalty."[80]

Mineral rights can also be leased, although oil and gas leases will expire after 5 years if the lease is not included in a producing unit at that time.[81, 82] Michigan's Oil and Gas Lease form also contains a clause that requires the lessee to notify the surface owner that they intend to enter the land before they begin operations.

The Michigan Department of Natural Resources (DNR) recognizes four types of mineral leases:[83]

- *Leasable development*, which allows for surface use so long as it conforms to lease terms.
- *Leasable development with restrictions*, which allows for use of the surface so long as it conforms to lease terms and additional added stipulations.

---

70 Quote by Mark Sweatman, director of the Michigan Department of Natural Resources' Office of Minerals Management. Digging into Severed Mineral rights. (2018) *Michigan Department of Natural Resources.* Accessible at https://www.michigan.gov/documents/dnr/DNRseveredmineralrights_640036_7.pdf.

71 MCL 319.101.

72 Stevens Mineral Co. v. Michigan, 164 Mich.App. 692, 696, 418 N.W.2d 130 (1987).

73 Rathbun v Michigan, 284 Mich 521, 534; 280 NW 35 (1938).

74 Fenton v. Miller, 94 Mich. 204, 214, 53 N.W. 957 (1892).

75 Amanda Narvaes. (2016.) How Courts Interpret Ambiguous Contract Language. *Drew, Cooper & Anding.*

76 United Coin Meter Co v Gibson, 109 Mich.App. 652, 657.

77 McCarty v Mercury Metalcraft Co, 372 Mich. 567, 575. "[W]here a latent ambiguity exists in a contract, extrinsic evidence is admissible to indicate the actual intent of the parties as an aid to the construction of the contract."

78 Mineral Rights. (2019). Michigan Department of Environment, Great Lakes, and Energy. Accessible at https://www.michigan.gov/documents/deq/ogs-oilandgas-mineral-rights_257977_7.pdf.

79 In general, EGLE classifies four types of mineral extraction: oil and gas, metallic, nonmetallic, and natural gas storage (Ibid).

80 Dep't of Transp. v. Goike, 560 N.W.2d 365, 366 (Mich. Ct. App. 1996).

81 MCL 319.109.

82 Mineral Rights. (2019). Michigan Department of Environment, Great Lakes, and Energy. Accessible at https://www.michigan.gov/documents/deq/ogs-oilandgas-mineral-rights_257977_7.pdf.

83 Mineral Rights. (2019). Michigan Department of Environment, Great Lakes, and Energy. Accessible at https://www.michigan.gov/documents/deq/ogs-oilandgas-mineral-rights_257977_7.pdf.

- *Leasable nondevelopment*, which does not allow for use of the surface unless there is separate, written permission from the DNR.
- *Non-leasable*, in which mineral rights will not be leased.

Mineral lease extraction and oil and gas exploration on state and private land are regulated by the Oil, Gas, and Minerals Division of EGLE.[84, 85] In addition, the Michigan DNR manages over 6.4 million acres of state mineral rights, including roughly 2.3 million acres of severed mineral rights in which the surface rights are owned by someone other than the State.[86]

Split Estates

Mineral rights in Michigan can be owned alongside with or separately from the surface rights.[87] They can be separated from the surface either by selling the land but retaining the mineral rights, selling the mineral rights but retaining the land, or by conveying the mineral and surface rights to separate entities altogether.[88, 89] If severed, the mineral rights become dominant and the surface subservient.[90] Therefore, the mineral rights holder has an implied easement to use as much of the surface as is "reasonably necessary for the development of the mineral estate."[91] Emphasis is heavily placed, however, on the fact that the use of the surface must be "reasonable."[92] If use of the surface is not "reasonable and necessary," it is considered excessive and the surface owner "may protect himself through an action in trespass or an appeal to equity for an injunction."[93]

Loss of title to oil and gas rights can occur if they are not used within a certain timeframe. Under Act 42 of 1963, any oil or gas interest that has not been used for a period of 20 years will revert back to the surface owner.[94] By "used," the Act refers to either having sold, leased, mortgaged, or transferred and respectively recorded in the register of deeds office; issuing a drilling permit of the land; producing or removing oil and gas; or using the interest for underground gas storage. Notably, however, this act only applies to oil and gas rights, and not to "other" mineral rights.

---

[84] Mineral Rights. (2019). Michigan Department of Environment, Great Lakes, and Energy. Accessible at https://www.michigan.gov/documents/deq/ogs-oilandgas-mineral-rights_257977_7.pdf.
[85] Oil and Gas Leases. (2021). Michigan Department of Natural Resources. Accessible at https://www.michigan.gov/documents/dnr/OG_FAQ_FINAL_401887_7.pdf#:~:text=Yes.%20In%20Michigan%2C%20all%20oil%20and%20gas%20exploration,select%20%E2%80%9CLand%E2%80%9D%20then%20click%20on%20the%20Mining%20tab.
[86] Digging into Severed Mineral Rights. (2018). Michigan Department of Natural Resources. Accessible at https://www.michigan.gov/documents/dnr/DNRseveredmineralrights_640036_7.pdf.
[87] Quote by Mark Sweatman, director of the Michigan Department of Natural Resources' Office of Minerals Management. Digging into Severed Mineral rights. (2018) *Michigan Department of Natural Resources.* Accessible at https://www.michigan.gov/documents/dnr/DNRseveredmineralrights_640036_7.pdf.
[88] Digging into Severed Mineral rights. Michigan Department of Natural Resources. Accessible at https://www.michigan.gov/documents/dnr/DNRseveredmineralrights_640036_7.pdf.
[89] Stevens Mineral Co. v. Michigan, 164 Mich.App. 692, 696, 418 N.W.2d 130 (1987).
[90] *Ibid.*
[91] Quote from Julie Manson, property manager with the Lease Management Unit of the DNR's Office of Minerals Management. Digging into Severed Mineral rights. *Michigan Department of Natural Resources.* Accessible at https://www.michigan.gov/documents/dnr/DNRseveredmineralrights_640036_7.pdf.
[92] Topp, Susan T. and Horn, William A. The Michigan Environmental Law Deskbook. *State Bar of Michigan.* Accessible at https://connect.michbar.org/envlaw/reports/deskbook/chapter20#_Toc325551736.
[93] *Ibid.*
[94] MCL 554.291.

Pore Space Ownership

While not addressed statutorily, Michigan has addressed ownership of pore space through case law and decided that its vesting belongs with the surface owner. In *Department of Transportation v. Goike*, the Michigan Court of Appeals examined a case involving the Department of Transportation acquiring the surface of a tract of land for a highway, but not the "fluid mineral and gas rights," which instead remained with the owner.[95] In their ruling, the court stated that the mineral owner only possesses a right to the minerals themselves, not to the land surrounding them. Therefore, they specifically held that "the storage space, once it has been evacuated of minerals and gas, belongs to the surface owner."[96] In addition, they held that a mineral right holder may store any "native" fluid minerals or gas to the chamber which has not yet been extracted, but they cannot introduce any; only the surface owner can introduce non-native foreign gas and minerals to the cavern. At the same time, however, the surface owner can only use the subsurface space *after* the mineral rights holder has extracted the native gas out of the cavern, as "it would be impossible to segregate plaintiff's gas from defendants' gas."[97]

Water Rights

Michigan classifies two separate types of surface water–inland waters, and waters from the Great Lakes.[98] For inland waters, the state utilizes riparian rights, which they define statutorily as "rights which are associated with the ownership of the bank or shore of an inland lake or stream."[99] Riparian rights holders also own the submerged land to the middle of the stream or inland lake, including the underlying minerals – but not the water itself.[100] Additionally, the state prohibits constructing or altering a marina, inland lake, or stream; or "structurally interfering" with an inland lake or stream's natural flow without a permit.[101]

The waters from the Great Lakes have been declared by the Legislature as a "public natural resource" that serves multiple uses, including municipal, public, industrial, commercial, mining, energy development and production, and water quality maintenance.[102] However, the state prohibits water diversions out of the basin and requires water use registration and reporting under the Great Lakes Basin Compact.[103] Any diversion of state waters[104] requires legislative approval and a demonstration that doing so serves a "public purpose" and results in no material harm to state waters.[105] The state also prohibits drilling for oil or gas under the Great Lakes, their connected bays or harbors, or their connecting waterways except under leases existing prior to April 5, 2002.[106]

---

95 Dep't of Transp. v. Goike, 560 N.W.2d 365, 366 (Mich. Ct. App. 1996).
96 Ibid.
97 Ibid.
98 MCL Act 451 of 1994, Ch. 1.
99 MCL 324.30101 (s).
100 Aalsburg v. Cashion, 384 Mich 236; 180 NW2d 792 (1970).
101 MCL 324.30102.
102 MCL 324.32702 (i).
103 MCL 324.32702 (b).
104 "Waters of the state" include: groundwater; lakes, including the Great Lakes bordering the state; rivers; streams; and all other water courses and bodies of water within the jurisdiction of the state, according to MR 323.2202 (p).
105 MCL 324.32703a.
106 MCL 324.502 (4).

Additionally, Michigan statute specifies that property owners who intend to make a new or increased large quantity withdrawal from the state waters[107] must register the withdrawal with EGLE and submit annual reports on withdrawals.[108]

The term "groundwater," as defined by EGLE regulations, refers to water below the land surface "in a zone of saturation."[109]

Lithium Ownership and Extraction

No information was identified about mines that produce lithium or extensive lithium deposits in Michigan, and our research did not identify any Michigan state laws or regulations that address lithium extraction or mining.

---

[107] MCL 324.32705. (1).

[108] These withdrawals are defined as "a new water withdrawal of over 100,000 gallons of water per day average in any consecutive 30-day period or an increase of over 100,000 gallons of water per day average in any consecutive 30-day period beyond the baseline capacity of a withdrawal."

[109] R 323.2201.

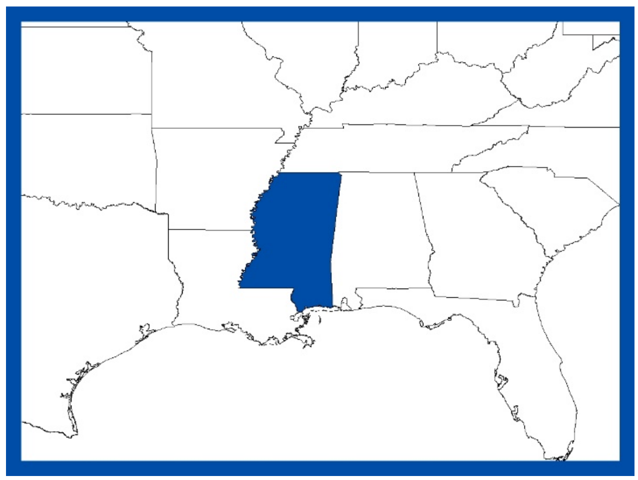
MISSISSIPPI

Executive Summary

Mississippi offers significant CO_2 storage capacity, primarily within saline formations, and a network of CO_2 pipelines runs from Mississippi into neighboring states. The state hosted the Cranfield CO_2 storage project, in which over 5 million metric tons of CO_2 were injected for EOR over a 5-year period. Mississippi recently enacted the Mississippi Geologic Sequestration of Carbon Dioxide Act, which expresses the state's intent to apply for Class VI primacy. The state does not appear to regulate pore space ownership.

Background

Mississippi contains federal, state, fee simple, and tribal land. The state extends 30,222,720 acres, 5.1% of which (1,552,634 acres) is owned by the Federal Government.[1] Federal land in Mississippi is largely distributed towards the center and the southern portion of the state. The only federally recognized tribe in Mississippi is the Mississippi Band of Choctaw Indians,[2] with a reservation consisting of roughly 35,000 acres of trust land across 10 counties in east-central Mississippi.[3]



Mississippi law operates under a common law system with 5 trial courts and a two-tier appellate court system.[4] The trial courts include two general jurisdiction courts (the chancery and circuit courts) and three limited jurisdiction courts (the county, justice, and municipal courts), with the County Courts having exclusive jurisdiction over eminent domain proceedings. The Court of Appeals consist of ten judges elected from five districts, and the Supreme Court consists of nine justices elected from three counties.

CCUS-related activities, including oil and gas production, Class II injection, and pipelines are overseen by the Mississippi Oil and Gas Board (MSOGB).

CCUS Activities in the State

Mississippi's oil and gas exploration dates back to the 1940's with the discovery of oil fields in the western part of the state. Fields currently operate in the southern and north-eastern parts of the state.[5] Some of the largest oil fields in the state (by cumulative production) are the Gwinville Field (discovered in 1944) in Jefferson Davis County, and the Baxterville Field (discovered in 1945) in the Lamar and

[1] Federal Land Ownership: Overview and Data. (2020.) *Congressional Research Service.* Accessible at https://fas.org/sgp/crs/misc/R42346.pdf.

[2] Federal and State Recognized Tribes (2019). *National Conference of State Legislatures.* Accessible at https://www.ncsl.org/legislators-staff/legislators/quad-caucus/list-of-federal-and-state-recognized-tribes.aspx.

[3] History. *Mississippi Band of Choctaw Indians.* Accessible at https://www.choctaw.org/aboutMBCI/history/index.html.

[4] About the Courts. *State of Mississippi Judiciary, Administrative Office of Courts*. Accessible at https://courts.ms.gov/aboutcourts/aboutthecourts.php.

[5] Production Charts by Field. https://www.ogb.state.ms.us/fieldcharts.php.

Marion Counties.[6] Mississippi's oil and gas can primarily be found in the Tuscaloosa Marine Shale, an unconventional oil reservoir in Southwest Mississippi.[7]

According to the MSOGB, total oil production for 2020, the most recent year with aggregated data, was 14,166,549 barrels, and total gas production in 2020 was 172,646,805 mcf (thousand cubic feet), produced by 5,156 oil and gas wells.[8] Annual oil production has averaged about 20.3 million barrels over the last 20 years.[9] According to US EPA data, there are 1,344 Class II injection wells in Mississippi, including 575 wastewater disposal wells and 769 wells used for EOR.[10]

In 2018, CO_2 emissions for Mississippi totaled 63.4 million metric tons, including 5.7 million metric tons from coal, 26.2 million metric tons from petroleum, and 31.4 million metric tons from gas.[11] Sources of CO_2 in the state include gas power plants, chemical plants, petroleum refineries, and gas processing facilities.[12] DOE estimates that a total of between 144.74 and 1,185 billion metric tons of CO_2 storage capacity is available in Mississippi. This includes between 139.02 and 1,172 billion metric tons in saline formations, between 5.44 and 12.45 billion metric tons in unmineable coal storage, and 0.28 to 0.62 billion metric tons in oil and gas reservoirs.[13]

The Southeast Regional Carbon Sequestration Partnership (SECARB) has been a major contributor to research into Mississippi's CO_2 storage capacity and potential.[14] SECARB initiated a carbon sequestration project at the Cranfield Site operated by Denbury Resources in southwestern Mississippi to demonstrate CO_2 sequestration capacity in Mississippi.[15] At the conclusion of the Cranfield project, 5,371,643 metric tons of CO_2 had been successfully injected for EOR and monitored for over 5 years from 2008 to 2014. Other plans for CO_2 utilization with coal gasification have faced barriers to implementation. There were plans for a 582-megawatt power plant in Kemper County to generate electricity using a carbon emission reducing coal gasification process, but technological and economic issues led the plant's owners to switch to using only natural gas, in 2018.[16]

MSOGB maintains a map of the crude oil, natural gas, and CO_2 pipelines located in Mississippi, as well as locations for refineries, gas compressor stations, oil pumping stations, oil fields, gas fields, and shallow salt domes. According to MSOGB's pipeline map, there are CO_2 pipelines extending from midwestern Mississippi into the southeast towards Southwestern Alabama, and through southwestern Mississippi into Louisiana.[17]

---

[6] Oil and Gas industry. Mississippi Encyclopedia. Available at: https://mississippiencyclopedia.org/entries/oil-and-gas-industry/.

[7] Mississippi State University. Oil and Gas Exploration in Mississippi: Tips for Landowners. Available at: https://extension.msstate.edu/sites/default/files/publications/publications/P3056_web.pdf.

[8] MSOGB. Annual Production Charts. Available at: https://www.ogb.state.ms.us/annprod.php.

[9] Ibid.

[10] EPA. UIC Injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.

[11] US Energy Information Association. State Carbon Dioxide Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.

[12] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.

[13] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

[14] Bureau of Economic Geology Gulf Coast Carbon Center. SECARB Cranfield Project. Available at: https://www.beg.utexas.edu/gccc/secarb-cranfield.

[15] DOE. DOE-Sponsored Mississippi Project Hits 1-Million-Ton Milestone for Injected CO2. Available at: https://www.energy.gov/fe/articles/doe-sponsored-mississippi-project-hits-1-million-ton-milestone.

[16] US Energy Information Association. Mississippi State Energy Profile. Available at www.eia.gov.

[17] MSOGB. Oil and Gas Pipe Line Map. Available at https://www.ogb.state.ms.us/.

Classification of CO_2: Commodity

Mississippi Geologic Sequestration of Carbon Dioxide Act declares that CO_2 is a valuable commodity to the citizens of the state for its use in EOR operations and because CCUS is an emerging industry with economic benefits to the state.[18] The state allows for a reduced sales tax rate for CO_2 sold to EOR projects or for permanent geologic sequestration.[19] Mississippi's oil and gas privilege tax is equal to 6% of the production value for oil and gas at point of production, but 3% of production value for oil produced by EOR.

Conversely, Mississippi does not appear to recognize CO_2 as a pollutant. The Mississippi Commission on Environmental Quality does not list CO_2 in their regulatory definition of "air contaminant," instead broadly defining it as, "particulate matter, dust, fumes, gas, mist, smoke, or vapor, or any combination thereof produced by processes other than natural."[20]

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

In accordance with Miss. Code Ann. § 53-11-1 et seq, the MSOGB oversees oil and gas production and Class II injection activities. Under Miss. Code Ann. § 11-27-47, counties regulate the construction and maintenance of pipelines for oil, gas, and CO_2 transmission.[21] Class I, III, IV, and V wells are regulated by the Mississippi Department of Environmental Quality (MDEQ), while Class VI wells are regulated by US EPA Region 4.[22]

No tribal or local laws or regulations address CCUS-related activities within the state.

Pipeline Regulations

Each county's board of supervisors has authority to regulate the construction and maintenance of CO_2 pipelines for transmission. Outside of county jurisdiction, the Mississippi Public Service Commission (MPSC) Pipeline Safety Division is certified by the US Pipeline & Hazardous Materials Safety Administration as having adopted the minimum federal regulations pursuant to the Natural Gas Pipeline Safety Act of 1968. They are responsible for enforcing state and federal pipeline safety regulations for intrastate natural gas pipeline facilities.[23] Offshore oil and gas pipelines are regulated by the MSOGB.[24]

Laws and Regulations for CO_2 Storage

The Mississippi Geologic Sequestration of Carbon Dioxide Act, which authorizes MSOGB to regulate carbon storage, was signed by the Governor on March 17, 2021.[25] The Act directs the OGB to apply for Class VI primacy on behalf of the state and authorizes the OGB to adopt rules and issue permits for Class VI wells and approve conversion of existing enhanced oil or gas recovery operations to a GS facility. Their duties include approving carbon storage facilities, regulating the use of CO_2 in EOR, and maintaining compliance with the Safe Drinking Water Act.[26] It also authorizes the assessment of a per-ton

---

[18] Miss. Code Ann. § 53-11-3.

[19] Miss. Code Ann. § 27-65-19. See also 32 Miss. Admin. Code Pt. IV, r. 6.01.

[20] Air Emission Regulations for the Prevention, Abatement, and Control of Air Contaminants. (2018.) *Mississippi Commission on Environmental Quality.* Accessible at https://www.mdeq.ms.gov/wp-content/uploads/2018/11/Air-Regs-Chapter-1-Air-Emission-Regulations-Amended-May-24-2018.pdf.

[21] Miss. Code Ann. § 11-27-47.

[22] MDEQ. Underground Injection Control Program. Available at: https://www.mdeq.ms.gov/land/waste-division/household-hazardous-waste/.

[23] MPSC. Gas Pipeline Safety. Available at: https://www.psc.ms.gov/pipeline/safety.

[24] MSOGB. Mississippi State Rules and Regulations. Available at: https://www.ogb.state.ms.us/

[25] Miss. Code Ann. § 53-11-1 et seq.

[26] Miss. Code Ann. § 53-11-1 et seq.

sequestration fee for a Carbon Dioxide Storage Fund that would cover the cost of post-injection oversight of geologic storage facilities. The Act was to take effect on July 1, 2021.

Mississippi has not been granted Class VI program primacy by EPA; therefore any Class VI wells in Mississippi are currently subject to the federal Class VI Rule at 40 CR 146.81 et seq and are overseen by EPA Region 4.

Regulation of Oil and Gas Production

Mississippi's onshore and offshore oil and gas well requirements can be found in the MSOGB list of statutes, rules of procedure, and statewide rules and regulations. Oil and gas wells must have a permit from the MSOGB, and prospective operators must submit a permit application that includes information about the well, including siting, depth, details about the proposed operation, and the well's construction. Applications for offshore wells must include well construction schematics, surface and bottom location from the lease boundaries, exploratory drilling or development plans, elevation of the derrick floor, depth to the top of significant paleontological and/or lithological markers, and, if located on a platform, information on the number of wells drilled and planned for drilling.[27] Applicants must also file a form for proof of financial responsibility for plugging the well in accordance with OGB and other state requirements. In addition, applicants are required to provide a financial assurance instrument whose value is based on the well depth and is paid to the Emergency Plugging Fund of the MSOGB. The permit application must also state whether the unit encompasses land owned by more than one owner and if there are multiple owners, the application must state whether they have agreed to development and drilling on their land. All oil and gas permits require public notice and hearing.

Mississippi rules regarding oil and gas well spacing differ depending on the depth of the top of the target pool and the formation age. Discovery wells in pools deeper than 12,000 feet and in pools in Pennsylvanian-aged and older formations below a measured depth of 3,500 feet must be located on a drilling unit of 80 contiguous surface acres or two contiguous quarter-quarter sections containing between 72 and 88 acres. The specific spacing rules relate to minimum drilling unit size, spacing from other wells completed in or producing from the same pool, and the exterior boundary of the drilling unit. However, the MSOGB may permit 160 acres if it would, "promote and encourage the orderly development of the pool." All other pools and oil wells must be located on a 36-to-44-acre drilling unit, upon which no other producible well may be located. Additional regulations pertaining to the exclusion of "island acreage" and well spacing can be found in the Mississippi State Rules and Regulations, Rule 7.[28]

MSOGB may order unitization if it is reasonably necessary to effectively carry out EOR operations or any other form of joint effort calculated to substantially increase the ultimate recovery of oil and/or gas or both, or to prevent waste.[29] MSOGB may do so only if it would protect the correlative rights of interested parties without increasing the cost of recovering the additional oil or gas.

Regulation of Injection Activities

Mississippi has Class II UIC program primacy under Section 1425 of the SDWA, granted on September 28,1983 to the MSOGB.[30] Rules for injection wells are provided in Rule 63, under the authority of 2019 Mississippi Code Title 53.[31] All new Class II wells in Mississippi must have a permit, and permits will only be issued if the operator shows that there will be no endangerment of a USDW. The permit application for a new EOR or produced fluid disposal well must be made on Oil and Gas Board

[27] MSOGB. Mississippi State Rules and Regulations, Rule OS-4.

[28] MSOGB. Mississippi State Rules and Regulations, Rule 7.

[29] Miss. Code Ann. § 53-3-103.

[30] 54FR8734.

[31] Mississippi Code Annotated, sections 53-1-1 through 53-1-47, inclusive and sections 53-1-71 through 53-1-77, inclusive (1972 and Supp. 1988).

Form No. 2.[32] It must include: information about the injection and confining zones and the lowest USDW; a well schematic and information on the size, grade and length of all casing strings; planned operating pressures and rates; and information on how the AoR was calculated based on the potential for pressure increase. Applicants must also submit evidence, such as a Letter of Credit or Surety Bond, of financial resources to close the injection well.

A permit applicant must give notice to all interested parties and the surface owner. If the application is for injection into a producing reservoir (pool), notice must be provided to all operators of wells in the pool. Permits are issued for the life of an injection well.

Environmental Laws

The Mississippi Department of Environmental Quality currently regulates activities that affect the state's air, land, and water. For additional information on water usages that relate to CCUS, see the discussion of "Water Rights," below.

Mississippi does not have specific air regulations related to flaring and venting of associated gas captured during oil production. However, operators must "recover all fumes and vapor in such tanks in a vapor recovery unit or flare it to the atmosphere using a flare stack with a permanent pilot attached."[33] The ambient air quality standards for Mississippi follow the national air quality standards set by the US EPA and CO_2 is not listed.[34]

The MSOGB rules for oil and gas activities define fresh water as "surface or subsurface water in its natural state useful for domestic, livestock, irrigation, industrial, municipal, and recreational purposes,"[35] but do not designate a threshold water quality level/TDS concentration. The UIC rules define a USDW similar to that as the federal definition.

Our research did not identify any rules pertaining to coal bed methane operations or induced seismicity.

Industrial Siting Requirements

Our research did not identify any industrial siting requirements in Mississippi other than those for designating a site as a hazardous waste facility.

Eminent Domain

Eminent domain law is addressed in Mississippi's constitution and in Mississippi statute. Under Article 3 of the Mississippi Constitution, "[P]rivate property shall not be taken or damaged for public use, except on due compensation being first made to the owner or owners thereof, in a manner to be prescribed by law; and whenever an attempt is made to take private property for a use alleged to be public, the question whether the contemplated use be public shall be a judicial question, and, as such, determined without regard to legislative assertion that the use is public."[36] Just compensation is considered to be the fair market value of the property actually taken, as well as any damage to the remaining property as a result of the acquisition and use of the property by the condemning authority.

---

[32] Rule 63.5.

[33] Mississippi Natural Gas Flaring and Venting Regulations. (2019*). U.S. Department of Energy, Office of Oil and Natural Gas*. Accessible at https://www.energy.gov/sites/prod/files/2019/08/f66/Mississippi.pdf.

[34] Ambient Air Quality Standards, Monitoring, and Attainment Planning. *Mississippi Department of Environmental Quality.* Accessible at https://www.mdeq.ms.gov/air/ambient-air-quality/#:~:text=Except%20for%20odor%2C%20the%20ambient%20air%20quality%20standards,as%20criteria%20pollutants%29%3A%20Nitrogen%20Dioxide%20%28NO2%29%20Ozone%20%28O3%29.

[35] MSOGB. Mississippi State Rules and Regulations. Rule 45.

[36] Mississippi Const. Article 3, Section 17.

All companies, associations, municipalities, and public utility and natural gas districts authorized "by and under the laws of the state of Mississippi" can exercise eminent domain.[37] This specifically includes the right to build or construct pipelines for the transportation of oil or gas, including CO_2 for use in connection with enhanced recovery of hydrocarbons.[38] This also includes the right to build pipelines and appliances along or across highways, waters, railroads, canals and public lands, above or below ground, provided they are not dangerous to people or property, and they do not interfere with the "common use" of roads, waters, railroads, canals, and public lands.[39] In 2016, a proposed bill would have required CO_2 pipelines to operate as common carriers, but it died in committee.[40]

The basic eminent domain procedure begins with the condemner filing eminent domain proceedings in the county courts.[41] The complaint will include a description of the property sought to be condemned, a statement of the right to condemn, and the interest or claim of each defendant.[42] The burden of proof as to the amount of compensation due to each defendant initially lies with the condemner in question; however, once the condemner makes a prima facie case of the value of the property, the burden shifts to the defendant to present evidence of a greater amount of just compensation.[43] The condemner in turn has the opportunity to rebut the evidence presented by the defendant. The case is then submitted to the jury to determine the proper compensation amount.[44]

At least 5 days before the hearing of the complaint, any defendant can file a motion to dismiss for failure to state a claim, upon which relief can be granted if: the plaintiff seeking to exercise the right of eminent domain is not entitled to that right; there is no public necessity for the taking of the property; or the contemplated use is not "a public use for which private property may be taken or damaged."[45]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Mineral rights in Mississippi can be held either in fee simple ownership to all surface and subsurface minerals, or just in surface rights ownership.[46] If the conveyance is made to two or more people, it will be held as estates in common.[47] All conveyances must be in writing and recorded with the county chancery court.[48] Mineral extraction on state lands requires a mineral lease from the Mississippi Major Economic Impact Authority,[49] but certain exceptions exist for offshore leases.[50] This includes the construction, laying and/or operation of state-owned pipelines, as well as transportation lines for state-

---

[37] Miss. Code Ann. § 11-27-47.
[38] Ibid.
[39] Ibid.
[40] MS HB907 (2016).
[41] Miss. Code Ann. § 11-27-5.
[42] Ibid.
[43] Scott, Paul R, and Quimby, Robert E. (2014.) Mississippi Eminent Domain Law and Procedure. *Smith, Phillips, Mitchell, Scott & Nowak, LLP.*
[44] Miss. Code Ann. § 11-27-25.
[45] Miss. Code Ann. § 11-27-15.
[46] Oil and Gas Exploration: Tips for Landowners. (2017.) *Mississippi State University Extension.* Accessible at http://extension.msstate.edu/sites/default/files/publications/publications/P3056_web.pdf.
[47] Miss. Code Ann. § 89-1-7.
[48] Miss. Code Ann. § 89-5-1.
[49] Miss. Code Ann. § 29-7-3.
[50] Mineral leases for offshore drilling operations are prohibited north of the coastal barrier islands with certain exceptions as described in Miss. Code Ann. § 29-7-3. Further, surface offshore drilling operations are not allowed within 1 mile of Cat Island. Also, the Commission may not lease any lands within 1 mile of an oyster reef lease for the purposes of drilling offshore for oil, gas, and other minerals.

owned natural gas and/or oil.[51] The lease in question must also contain a lease royalty to the state of at least 3/16 of the oil and gas or other minerals.[52]

When interpreting mineral contracts under Mississippi law, the courts employ a "three-step inquiry" to determine the legal intent of the parties.[53] First, a four-corners search of the contract is employed to determine the "plain meaning of the words."[54] If the terms are ambiguous and can be interpreted in more than one way, the court applies the discretionary 'canons' of contract construction." If traditional canons of construction do not resolve the ambiguity, the courts consider extrinsic evidence of the parties' intent.[55] Our research did not yield any discussion of whether CO_2 was included in a grant of minerals. However, the Mississippi Geologic Sequestration of Carbon Dioxide Act specifies that neither injection nor an order from the state will affect ownership of CO_2, nor will it inhibit the voluntary conveyance of title to the CO_2 by the owner. The OGB can also issue any necessary order protecting the title of an owner to CO_2 injected into a geologic sequestration facility. Additionally, the Act employs and protects correlative rights.[56]

Split Estates

Mineral severance in Mississippi can arise for two reasons: either the grantor listed the minerals as a reservation when the surface rights were conveyed or because only the mineral interest was conveyed.[57] Once they have been severed, title to the mineral rights cannot be acquired by adverse possession of the surface alone.[58] According to the Mississippi College Law Review, "practically all jurisdictions" recognize that severed minerals can only be adversely possessed "through actual drilling or at least by some type of operation for the production of minerals."[59]

The Mississippi Geologic Sequestration of Carbon Dioxide Act includes a provision in § 53-11-11 that addresses approval in writing by a majority interest of the surface interests and any existing mineral interests in order to approve the sequestration facility.

Mississippi recognizes the mineral estate as dominant over the surface estate.[60] Therefore, mineral estate owners or lessees may use as much of the surface as is "reasonably necessary" to recover minerals, without liability for surface damage.[61] Mineral rights holders will be held liable for damages if they use more land than is reasonably necessary or if they deliberately or negligently destroy the land; however, Mississippi courts have previously held that the surface owner could not "recover damages for the location of the well, drilling pad, or pipeline, without any evidence that the location was

[51] Miss. Code Ann. § 29-7-7.
[52] Miss. Code Ann. § 29-7-3.
[53] *Royer Homes of Miss. Inc. V. Chandeleur Homes, Inc.*, 857 So 2d 748, 752 (Miss. 2003).
[54] Ibid.
[55] Ibid.
[56] Miss. Code Ann. § 53-11-9.
[57] Jones, Shirley N. (1983). Constitutional and Practical Problems in Legislation to Termination Non-Productive Mineral Interests. *Mississippi College Law Review*. Accessible at https://dc.law.mc.edu/cgi/viewcontent.cgi?article=1102&context=lawreview.
[58] Huddleston v. Peel, 119 So. 2d 921 (Miss. 1960).
[59] Jones, Shirley N. (1983). Constitutional and Practical Problems in Legislation to Termination Non-Productive Mineral Interests. *Mississippi College Law Review*.
[60] Striking the Balance: Enforcing surface restrictions on mineral estate in Mississippi following Petro Harvester v. Keith. *American Association of Professional Landmen.* Accessible at https://www.akingump.com/a/web/mH2htCRkqeSdnrcxrfu4TW/akin-gump-july-aug21.pdf.
[61] Union Prod. Co. v. Pittman, 245 Miss. 427, 433-34, 146 So.2d 553, 555 (1962).

unreasonable."[62] According to the American Association of Professional Landmen, this reiterates the state's position of limiting recovery to instances of unreasonableness.[63]

Mississippi does not have a dormant mineral law that reverts ownership of the mineral estate back to the surface owner after a period of unuse. Over the past decade, various bills were proposed, but none passed through their respective committees.[64] The state does, however, have a statutory provision in place to appoint the chancery court clerk as the receiver of any "nonresident" or "unknown" owners of mineral interests, which they can then use (under court order) to execute and deliver a mineral lease to a lessee.[65]

Pore Space Ownership

Mississippi does not explicitly discuss pore space ownership in state statute. However, ownership requirements are broadly discussed for CO_2 geologic sequestration facilities. The majority interest of subsurface rights owners must consent to the storage of CO_2 in underground reservoirs.[66] This is further described in Mississippi Code 53-11-11 in the context of unit operations. In order to conduct operations of a geologic sequestration facility, approval must be obtained from a majority interest of the surface interest and, if separate, a majority interest of all rights to the subsurface reservoir.[67]

Water Rights

Mississippi is a riparian rights state.[68] Water resources are statutorily declared subject to beneficial use[69] "to the fullest extent of which they are capable."[70] Additionally, the conjunctive use of groundwater and surface water is encouraged for the reasonable and beneficial use of all water resources of the state.[71] All water, including surface[72] and groundwater,[73] is declared "to be among the basic resources of this state to therefore belong to the people of this state and is subject to regulation."[74] All uses of water (except for domestic purposes) require a permit[75] and the right to use of water granted by the permit automatically terminates after 10 years unless a renewal water permit is requested.[76]

---

[62] Abraham v. Sklar Expl. Co., 408 F. Supp. 2d 244, 250 (S.D. Miss. 2005), as discussed in *Striking the Balance: Enforcing surface restrictions on mineral estate in Mississippi following Petro Harvester v. Keith.*

[63] Striking the Balance: Enforcing surface restrictions on mineral estate in Mississippi following Petro Harvester v. Keith. *American Association of Professional Landmen.* Accessible at https://www.akingump.com/a/web/mH2htCRkqeSdnrcxrfu4TW/akin-gump-july-aug21.pdf.

[64] For example, Mississippi Senate Act (2015 Regular Session - SB 2428) and Mississippi House Act (2012 Regular Session – HB 531).

[65] Miss. Code Ann. § 11-17-33.

[66] Miss. Code Ann. § 53-11-9.

[67] Miss. Code Ann. § 53-11-11.

[68] Pepper, Jack W. "Mississippi Water Rights Law." Journal (American Water Works Association), vol. 50, no. 8, 1958, pp. 997–1001. JSTOR, www.jstor.org/stable/41255884.

[69] "Beneficial use" means the application of water to a useful purpose as determined by the Commission on Environmental Quality, but excluding waste of water, as referenced in Miss. Code Ann. § 51-3-3(e).

[70] Miss. Code Ann. § 51-3-1.

[71] Ibid.

[72] "Surface water" means water occurring on the surface of the ground, as referenced in Miss. Code Ann. § 51-3-3(b).

[73] "Groundwater" means water occurring beneath the surface of the ground, as referenced in Miss. Code Ann. § 51-3-3(n).

[74] Ibid.

[75] Miss. Code Ann. § 51-3-5.

[76] Miss. Code Ann. § 51-3-9.

The Mississippi Commission of Environmental Quality can issue a water use warning or declare and delineate a water use caution area, if: the "mining" of an aquifer is occurring[77] or existing water resources, including surface water and/or groundwater resources are inadequate to meet present or reasonably foreseeable needs. If the commission declares and delineates a water use caution area, the Permit Board may require permits for withdrawals of water in excess of 20,000 gallons per day.

In addition, water rights cannot be utilized if doing so will: impair the effect of stream standards set under the pollution control laws;[78] impair navigability of a watercourse; or result in the mining of any aquifer (unless the Permit Board determines that the use is essential to the safety of life and property or the applicant has applied for permit or made a plan to acquire water from another source in lieu of the water being mined).[79]

Lithium Ownership and Extraction

Our research did not identify any lithium mining operations in Mississippi or specific requirements related to lithium extraction or the presence of lithium in produced waters.

[77] "Mining of aquifer" means the withdrawal of groundwater from hydrologically connected water-bearing formations in a manner in excess of the standards established by the commission, as referenced in Miss. Code Ann. § 51-3-3(m).

[78] "Minimum flow" means the average streamflow rate over 7 consecutive days that may be expected to be reached as an annual minimum no more frequently than 1 year in 10 years (7Q10), as referenced in Miss. Code Ann. § 51-3-3(i). This can also include any other streamflow rate that the commission establishes using generally accepted scientific methodologies considering biological, hydrological, and hydraulic factors.

[79] Miss. Code Ann. § 51-3-7 (4-6).

NEBRASKA

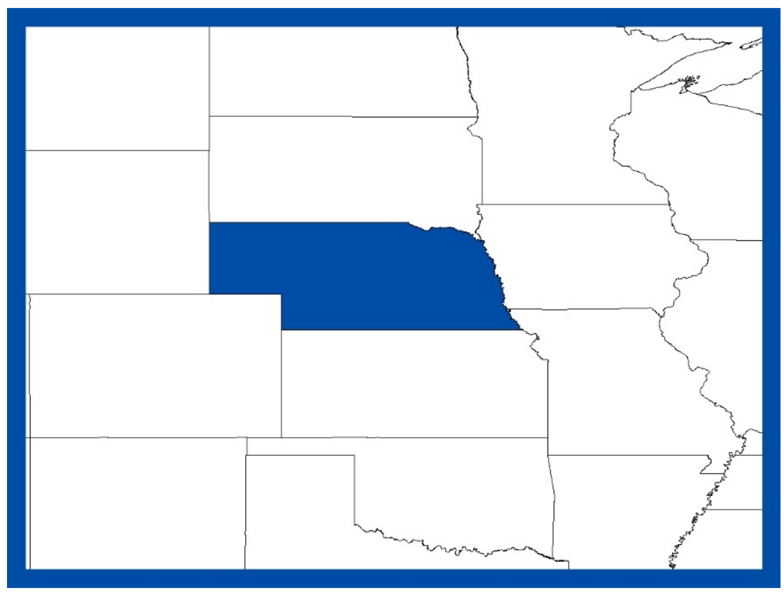
Executive Summary

CCUS operators in Nebraska may benefit from the state's long experience with oil and gas production dating back to 1939. Additionally, the state offers significant storage capacity in saline formations including the Cloverly Formation and the Cedar Hills Formation. The state enacted the Nebraska Geologic Storage of Carbon Dioxide Act in January 2021 to promote the geologic storage of CO_2. This Act addresses many of the concerns of CCUS operators, including use of subsurface strata and ownership of the stored CO_2 during and after a CO_2 injection project. It also establishes a Carbon Dioxide Storage Facility Trust Fund to defray the expenses incurred for long-term monitoring and management of closed storage facilities.

Background

Nebraska contains federal, state, fee, and tribal land. The state extends 49,031,680 acres, of which 546,852 (1.1%) are owned by the federal government. Federal land is concentrated in the upper west corner of the state. There are 6 federally recognized tribes, including the Iowa Tribe; Omaha Tribe; Ponca Tribe; Sac & Fox Nation; Santee Sioux Nation; and Winnebago Tribe. While there are 7 recognized tribal reservations,[1] there are no state-recognized tribes.[2]

Nebraska's judicial system uses common law. The state constitution distributes judicial power among the Supreme Court, Court of Appeals, district courts, and county courts.[3] The district courts, Nebraska's general jurisdiction trial courts, can also function as appellate courts in deciding appeals from "various administrative agencies and from most county court cases."[4] The county courts, meanwhile have specified limited jurisdiction. The Court of Appeals consists of six judges appointed by the Governor and is split into two panels consisting of three judges each. In cases appealed to the Court of Appeals, a petition to bypass may be filed with the Supreme Court. The Supreme Court consists of a Chief Justice and six associate justices. All state courts operate under the administrative direction of the Supreme Court. There is no special court for water or mineral rights disputes.



Oil and gas-related activities are overseen by the Nebraska Oil and Gas Conservation Commission (NOGCC), whose mission is to allow the development of the state's oil and natural resources while promoting the health, safety, and environment of Nebraska.[5] Pipelines in the state are overseen by the Nebraska Public Service Commission.

[1] Nebraska Indian Reservations. (2014.) Native American Tribes of the U.S. Accessible at https://native-americans.com/nebraska-indian-reservations/.

[2] Federal and State Recognized Tribes. (2020). *National Conference of State Legislators*. Accessible at https://www.ncsl.org/legislators-staff/legislators/quad-caucus/list-of-federal-and-state-recognized-tribes.aspx#ne.

[3] Branch Overview. State of Nebraska Judicial Branch. Accessible at https://supremecourt.nebraska.gov/branch-overview.

[4] Ibid.

[5] NOGCC. About. Available at: http://www.nogcc.ne.gov/.

CCUS Activities in the State

Significant crude oil production in Nebraska began in 1939 with a commercial production well drilled in the Falls City Basin field in Richardson County.[6] According to the Nebraska Department of Environment and Energy, Nebraska's crude oil production was 1,912,000 bbls in 2019. Natural gas production in 2016, the earliest year with an available cumulative total, was 526.4 mmcf (million cubic feet). Annual oil production has averaged about 2.4 million barrels over the last 20 years.[7] Crude oil and natural gas fields are primarily found in the Denver-Julesberg Basin[8] which extends from Colorado along the western and southern borders of Nebraska.[9]

As of December 31, 2019, there were 1,441 producing oil and gas wells in Nebraska. According to US EPA data, there are 630 Class II injection wells in Nebraska, including 146 wastewater disposal wells and 484 EOR wells.[10]

In 2018, CO_2 emissions in Nebraska totaled 52.5 million metric tons, including 25.2 million metric tons from coal, 16.8 million metric tons from petroleum, and 10.5 million metric tons from gas.[11] DOE estimates that a total of 23.66 to 111.98 billion metric tons of CO_2 storage capacity is available in Nebraska, primarily in saline formations (which account for between 23.65 and 111.91 billion metric tons), with the remainder (between 0.01 to 0.07 billion metric tons) in oil and gas reservoirs.[12]

The Energy and Environmental Research Center (EERC) and DOE's NETL have partnered with the Nebraska Public Power District (NPPD) for a feasibility study to demonstrate Nebraska's potential for carbon capture and storage. This project was conducted as part of DOE's CarbonSAFE project, in which each project must demonstrate the potential to store at least 50 million tons of CO_2 over a 25-year period. The project is taking place at the Gerald Gentleman Station 2, the only source of CO_2 in the state capable of meeting the 50 Mt criterion. Additional sources of CO_2 in the state include ethanol and ammonia facilities, coal power plants, and cement kilns.[13] The Cloverly Formation, comprised of sandstone with interbedded shale, is the primary target for storage, with the Cedar Hills Formation identified as a potential alternative storage zone.[14] Both the Cloverly and Cedar Hills Formations extend into the Denver-Julesberg Basin. The Cloverly Formation has an estimated storage capacity between 20.8 and 67.4 billion tons of CO_2, while the Cedar Hills Formation has an estimated storage capacity between 0.5 and 3.0 billion tons.[15]

Although it appears that Nebraska does not have a strong CO_2 pipeline infrastructure, research suggests that there is nascent movement towards building carbon storage infrastructure. In March 2021, plans were announced to build a 1,200-mile pipeline which would accept carbon emissions from biofuel

[6] History Nebraska. Southeast Nebraska's Oil Boom. Available at: https://history.nebraska.gov.
[7] DEE. Nebraska's Crude Oil Production. Available at: https://neo.ne.gov/programs/stats/inf/43.html#1.
[8] The Drillings. Oil and Gas Leases in Denver Basin. Available at: https://thedrillings.com/lands/oagf-33.
[9] DEE. Nebraska's Crude Oil Production by County. Available at: https://neo.ne.gov/.
[10] EPA. UIC Injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.
[11] US Energy Information Association. State Carbon Dioxide Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.
[12] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[13] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.
[14] DOE, NETL. Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study. June 29, 2018.
[15] U.S. DOE. Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study.

facilities across Nebraska, Iowa, Minnesota, South Dakota, and Illinois, where it would be sequestered. The project is expected to sequester 12 million metric tons per year.[16]

Classification of CO_2: Commodity

Nebraska likely considers CO_2 as a commodity, but not a pollutant. The Nebraska Geologic Storage of Carbon Dioxide Act, passed in January 2021, specifically declares that stored CO_2 is a "potentially valuable commodity."[17] Additionally, Nebraska collects a severance tax on oil and gas mining equal to 3% for natural gas and nonstripper oil, although oil or gas used only in severing operations or for repressuring or recycling purposes is exempt.[18] In addition, the state imposes a conservation tax on the value of oil and natural gas collected.[19]

While the Nebraska Geologic Storage of Carbon Dioxide Act does call for the reduction of greenhouse gases, Nebraska does not appear to enforce any CO_2-specific regulations. The ambient air monitoring sites throughout Nebraska follow EPA's lead in only monitoring the following pollutants: particulate matter, ozone, carbon monoxide, sulfur dioxide, total reduced sulfur, pollutant deposition, and regional haze.[20] The state also does not appear to participate in any Cap-and-Trade program.

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

CCUS-related activities are regulated by the NOGCC (which regulates oil and gas production wells and Class II injection wells) and the Nebraska Public Service Commission (NPSC), which regulates oil and gas pipelines. No tribal or local laws or regulations address CCUS-related activities in the state.

Pipeline Regulations

In addition to adopting the federal rules included in Title 49 CFR governing pipeline safety, Nebraska has rules for major oil and gas pipelines requiring either the Governor's approval or a permit from the Nebraska Public Service Commission (NPSC).[21] In accordance with the Major Oil Pipeline Siting Act, a major oil pipeline is defined, "for the transportation of petroleum, or petroleum components, products, or wastes, including crude oil or any fraction of crude oil, within, through, or across Nebraska, but does not include in-field and gathering lines."[22] This definition does not appear to directly apply to transportation of CO_2 and our research did not identify any regulations specific to CO_2 pipelines.

Laws and Regulations for CO_2 Storage

The Nebraska Geologic Storage of Carbon Dioxide Act gives NOGCC regulatory authority over the construction, operation, monitoring, and closure of CO_2 storage facilities.[23] The Act establishes a Carbon Dioxide Storage Facility Trust Fund to defray the expenses incurred by the NOGCC for long-term monitoring and management of a closed storage facility.[24] The Fund will be built by fees collected from operators for each ton of CO_2 injected. Section 19 of the Act also provides that, at the cessation of injection, the Commission may issue a certificate of project completion, at which time, title to the storage facility and to the stored CO_2 transfers to the state; the operator is released from all regulatory

---

[16] Des Moines Register. Iowa, Texas Companies Propose Multi-Billion-Dollar Carbon-Capture Pipelines across Iowa, Midwest. Available at: www.desmoinesregister.com.

[17] Neb. Rev. Stat. 57-1602.

[18] Neb. Rev. Stat. 57-700 to 57-719.

[19] Neb. Rev. Stat. 57-919.

[20] Ambient Air Monitoring Program. Nebraska Department of Environment & Energy. Available at http://dee.ne.gov/NDEQProg.nsf/OnWeb/AAMP

[21] NPSC. Natural Gas and Pipeline Rules and Regulations.

[22] Neb. Rev. Statute 57-1404.

[23] Neb. Rev. Stat. 57-1602.

[24] Ibid.

requirements, financial assurance obligations, and long-term monitoring; and managing the storage facility is the state's responsibility to be overseen by the Commission.

Nebraska has not been granted Class VI program primacy by EPA; therefore, any Class VI wells in Nebraska are currently subject to the federal Class VI Rule at 40 CFR 146.81 et seq and are overseen by EPA Region 7. Applicants seeking to inject CO_2 for short-term or permanent storage must obtain permits from both the NOGCC and the agency that oversees the relevant class of injection well.[25] In the absence of Class VI primacy, this could potentially necessitate permits with both NOGCC and EPA Region 7 for CO_2 injection that is intended for long-term storage.

Regulation of Oil and Gas Production

Nebraska's requirements for oil and gas wells are found in the NOGCC's "Rules of Practice and Procedure before the Oil and Gas Conservation Commission of the State of Nebraska." All operators seeking to drill must submit a notice of intent, known as "Form 2," to the NOGCC and receive approval before beginning drilling. While the oil and gas regulations do not identify specific information that must be included with a permit application, Form 2 requests information about the depth of the well, the deepest formation to be penetrated, and the proposed casing and cementing program.[26] The applicant must also provide a financial assurance bond of at least $10,000 per well or hole, or a "blanket" bond of at least $100,000 for all associated wells or holes.[27]

Per Chapter 3 of the NOGCC Oil and Gas Rules of Practice and Procedure, oil and gas wells must be located on subdivisions that do not vary substantially from the subdivisions of other wells in the same pool. All wells drilled deeper than 2,500 feet that do not have established spacing patterns must be drilled on a 40-acre legal subdivision and may not be located within 500 feet from the subdivision boundaries. Wells shallower than 2,500 feet may not be located within 300 feet of the subdivision boundaries.[28]

Operators may apply for unit operation. The application must include the names and addresses of owners, a plat outlining the proposed area for unitization, a description of the operation, all relevant producing or produced formations, names and descriptions of reservoirs and pools that would be operated, a proposed unitization plan, and a proposed operation plan.[29]

Regulation of Injection Activities

EPA granted primacy under Section 1425 of the SDWA to the Nebraska Oil and Gas Conservation Commission for the Class II UIC program on February 3, 1984.[30] The Nebraska Department of Environmental Quality has primacy for all other classes of injection wells.

Chapter 4 of the NOGCC Rules and Regulations address Class II injection wells; they are issued under authority of Chapter 57 of the Revised Statutes of Nebraska.[31] All Class II wells must be approved by the Commission and have a permit.[32] Permit applications must include a description of the operation, a schematic of the well, the depth of the injection zone, information about the injection zone, information showing that operations will not initiate fractures, and information about the lowest freshwater zone,

---

[25] Ibid.
[26] NOGCC. Form 2. Notice of Intent to Drill or Re-Enter. Available at: http://www.nogcc.ne.gov/Publications/NE_CodeChapter3-003.pdf
[27] Chapter 1, Rule 004.
[28] Chapter 3, Rule 013.
[29] Chapter 5, Rule 001.
[30] 48FR4777.
[31] NOGCC Title 267; Revised Statutes of Nebraska 57-901 to 57-923.
[32] Chapter 4, Rule 002.

including the distance between the injection zone and the freshwater zone.[33] Notice of a Class II permit application must be provided to each person owning a fee, leasehold, mineral or royalty interest within the secondary recovery project area or within one-half mile of the injection well, and the application is subject to a public hearing.[34] Class II permits are issued for the life of the well, unless revoked for cause.[35]

Environmental Laws

Nebraska's oil and gas regulations define fresh water similar to the federal definition of a USDW, i.e., a source of water used for drinking water purposes, or water in an aquifer with less than 10,000 parts per million total dissolved solids, unless the aquifer is exempted by the Director of the NOGCC.[36]

Nebraska's Environmental Protection Act defines water pollution as, "the manmade or man-induced alteration of the chemical, physical, biological, or radiological integrity of the water." It also defines "air contaminant" or "air contamination" as "the presence in the outdoor atmosphere of any dust, fume, mist, smoke, vapor, gas, other gaseous fluid, or particulate substance differing in composition from, or exceeding in concentration, the natural components of the atmosphere;" and "air pollution" as "the presence in the outdoor atmosphere of one or more air contaminants or combinations thereof in such quantities and of such duration as are or may tend to be injurious to human, plant, or animal life, property, or the conduct of business."[37] Under Nebraska's Environmental Protection Act, the Nebraska Department of Environment and Energy is the state water pollution, air pollution, and solid waste pollution control agency. Nebraska has adopted federal rules for emissions standards consistent with the Clean Air Act.[38] Our research did not identify any regulations specific to CO_2 or methane as an air pollutant.

Injection-associated seismic activity does not appear to be a concern in Nebraska. One report describes increases in seismic activity in central Nebraska in 2018 but notes that the events were at least 75 km from water injection wells.[39] Nebraska does not have rules addressing induced seismicity for injection or production wells. However, under the Nebraska Geologic Storage of Carbon Dioxide Act, issuance of a permit from the Commission requires a comprehensive geologic study which includes a seismic risk assessment in accordance with the US EPA UIC Program.[40]

Industrial Siting Requirements

Our research did not identify any industrial siting requirements in Nebraska other than those for designating a site as a hazardous waste facility.

Eminent Domain

Nebraska's eminent domain laws can be found in Section X-6 of the state Constitution, as well as Article 7, Chapter 76 of their revised statutes. According to state statute, the right of eminent domain lies with the state of Nebraska.[41, 42] In addition, any company transporting or conveying crude oil, petroleum, or gas through or across the state may exercise eminent domain as is reasonably necessary for the

---

[33] Chapter 4, Rule 004.02.
[34] Chapter 4, Rule 005.
[35] Chapter 4, Rule 008.01.
[36] Neb. Admin Code 267-1-002.
[37] Neb. Rev. Statute 81-1502.
[38] Neb. Rev. Statute 81-1505.
[39] Irina Filina, et al. Seismicity in Nebraska and Adjacent States: The Historical Perspective and Current Trends.
[40] Neb. Rev. Stat. 57-1602. Section 10(11).
[41] Neb. Rev. Stat. 76-725.
[42] Neb. Rev. Stat. 76-701.

construction, operation, and maintenance of the pipeline.[43, 44] Any person who transports, transmits, conveys, or stores liquid or gas by pipeline in Nebraska intrastate commerce is considered to be a common carrier.[45] Furthermore, the underground storage of natural gas or liquefied petroleum gas is considered to fall within the public interest if doing so promotes the conservation or development of natural gas resources in the state.[46] CO_2 storage as it relates to eminent domain has not been addressed in Nebraska statute but could qualify as public interest, similar to natural gas and liquified petroleum gas storage.

The procedure for condemnation begins when the condemner files a petition to commence eminent domain proceedings in the county court where the property is located, which is then filed by the State Attorney General on behalf of the Nebraska Department of Transportation.[47] The petition must include a statement of the authority for the acquisition, a description of the property and the quantity needed, the purpose for which the land will be used and the reason for selecting that particular location, and evidence of prior attempts to negotiate in good faith with the property owner.[48] The Judge will then appoint three appraisers to view the property and review statements of the land value and any damages.[49, 50] The appraisers will then file their findings of value with the County Court. If either party disagrees with the report, they may appeal to the District Court for another determination of value by a jury.[51, 52]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Mineral rights in Nebraska are vested property rights that can be created through a conveyance, a reservation or exception on title, descent, or devise.[53, 54] If severed, the mineral estate and the surface estate become two distinct estates with two separate titles, with the mineral estate held in fee simple.[55] Mineral rights can also be leased, although the lessees generally do not acquire any title to the surface. They are, however, entitled to possess and use the surface of the land to the extent reasonably necessary to explore, extract, and market the minerals, as well as oil or gas.[56, 57]

---

[43] Neb. Rev. Stat. 57-1101.
[44] The exception to this statute is for any "major oil pipeline" as defined in section 57-1404, who must comply with section 57-1503 and receive the approval of the Governor for the route of the pipeline or shall apply for and receive an order approving the application under the Major Oil Pipeline Siting Act, prior to having the rights provided under this section.
[45] Neb. Rev. Stat. 75-501.
[46] Neb. Rev. Stat. 57-602.
[47] Neb. Rev. Stat. 76-704.
[48] Neb. Rev. Stat. 76-704.01.
[49] Neb. Rev. Stat. 76-706.
[50] Neb. Rev. Stat. 76-710.
[51] Neb. Rev. Stat. 76-712.
[52] Neb. Rev. Stat. 76-715.
[53] Wheelock v. Heath, 201 Neb. 835, 272 N.W.2d 768 (1978).
[54] Mattoon, Steven. (2020.) What Real Estate and Probate Attorneys Should Know About Oil and Gas. Nebraska State Bar Association. Accessible at https://cdn.ymaws.com/www.nebar.com/resource/resmgr/practice_tools/nsba_library/2020/9-25-20_REPT_Complete.pdf.
[55] Ibid.
[56] Ibid.
[57] Per Neb. Rev. Stat. 57-218 and 219, the governing board of all lands of the State and all other governmental subdivisions of the State have authority to lease lands under their control for oil and gas exploration and development. These oil and gas leases last for 10 years and as long thereafter as oil or gas is produced in paying quantities.

As with other conveyances of real estate, the courts must carry into effect the "true intention of the parties" listed in the instrument per state law.[58] In determining intent, Nebraska courts are not confined to a strict or literal interpretation of the language used if doing so would "[F]rustrate the intention of the parties thereto as gathered from the whole instrument."[59] When the intention of the parties in the contract is obscure or uncertain, the courts may subordinate rules of construction and permissible surrounding circumstances.[60] Additionally, terms that are ambiguous should be construed in favor of the defendant who did not prepare it.[61]

The term "minerals" is defined in *Belgum v. City of Kimball*, which involved the City of Kimball drilling and producing oil from a test well on the plaintiff's real estate. The plaintiff alleged that they were entitled to a proportionate share of the oil produced, on the basis that they are the owner of the oil, gas, and other minerals. The city contended that it was the owner of the oil, gas, and other minerals. In their ruling, the Nebraska Supreme Court had stated, "While there is apparently no issue raised in the instant case as to whether or not oil, petroleum, and natural gas are minerals, we believe that it would be proper to state that the term 'mineral' ordinarily embraces oil or petroleum and natural gas."[62] It is unclear that the courts would include CO_2 in a grant of minerals.

The Nebraska Geologic Storage of Carbon Dioxide Act addresses ownership of the stored CO_2 during and after a CO_2 project. Under this Act, the storage operator has title to the injected and stored CO_2 until the Nebraska Oil and Gas Conservation Commission issues a certificate of project completion.[63]

Split Estates

A severed mineral interest in Nebraska occurs by way of conveyance or reservation. When severed, the mineral estate becomes dominant and the surface subservient.[64] The owner of a severed mineral interest therefore has an implied right of access to the severed estate to remove minerals and reduce minerals to possession.[65] In addition, any owner of the surface estate or the severed mineral interest may apply to the assessor of the county where such surface estate is located to place such severed mineral interest on the tax list of the county.[66]

Nebraska does contain a statutory provision for the abandonment of severed mineral interests in the event that the mineral hold has not publicly "exercised ownership"[67] within the past 23 years immediately prior to the filing of the action.[68] However, in *Monahan Cattle Co. v. Goodwin*, it was

---

[58] Neb. Rev. Stat. 76-205.

[59] Gettel v. Hester, 165 Neb. 573, 86 N.W.2d 613 (1957).

[60] Elrod v. Heirs, Devisees, etc., 156 Neb. 269, 55 N.W.2d 673, 676.

[61] People's State Bank v. Smith, 120 Neb. 29, 231 N.W. 141.

[62] Belgum v. City of Kimball, 163 Neb. 774, 81 N.W.2d 205, 62 A.L.R.2d 1295.

[63] Neb. Rev. Stat. 57-1619.

[64] Mattoon, Steven. (2020.) What Real Estate and Probate Attorneys Should Know About Oil and Gas. Nebraska State Bar Association.

[65] Reed v. Williamson, 164 Neb. 99, 82 N.W.2d 18 (1957) Mentioned in *What Real Estate and Probate Attorneys Should Know About Oil and Gas.*

[66] Neb. Rev. Stat. 57-236.

[67] Exercise of the right of ownership under this statute occurs by: acquiring, selling, leasing, pooling, utilizing, mortgaging, encumbering, or transferring such interest or any part thereof by an instrument which is properly recorded in the county where the land from which such interest was severed is located; drilling or mining for, removing, producing, or withdrawing minerals from under the lands or using the geological formations, or spaces or cavities below the surface of the lands for any purpose consistent with the rights conveyed or reserved in the deed or other instrument which creates the severed mineral interest; or recording a verified claim of interest in the county where the lands from which such interest is severed are located.

[68] Neb. Rev. Stat. 57-229.

declared that this statute was unconstitutional insofar as the statutory provisions could be interpreted to be retroactive in their operation.[69]

Pore Space Ownership

The Nebraska Geologic Storage of Carbon Dioxide Act declared the use of any subsurface stratum (and any materials and fluids contained therein) for the geologic storage of CO_2 to be a "reasonable and beneficial use."[70] Under this Act, the title to any reservoir estate underlying the surface of lands/waters lies vested in the surface owner, unless it was already severed in a previous conveyance.[71] Therefore, a conveyance of the surface estate also conveys the reservoir estate, whereas a conveyance of the mineral estate does not, unless explicitly stated.[72] However, in determining the priority of subsurface uses between a severed mineral estate and reservoir estate, the severed mineral estate is dominant *regardless* of whether reservoir estate ownership is vested in several surface owners or is owned separately from the surface.[73] In addition, the reservoir estate owner has no right to use the surface estate beyond what was set out as the instrument used to convey title.

Water Rights

Surface water in Nebraska is declared the property of the public and dedicated to public use, subject to appropriation,[74] including appropriation for storage in a surface reservoir and for underground water storage. Nebraska was originally a Riparian rights state but has since statutorily become a prior appropriation state. Between appropriators, first in time is first in right.[75] According to the Institute of Agriculture and Natural Resources, water rights are issued by the Nebraska Department of Natural Resources and legally attach to either a parcel of land or a position in the state, which transfers with the land to subsequent owners.[76]

Correlative rights govern Nebraska's groundwater usage. According to the Institute of Agriculture and Natural Resources, the usage of correlative rights means that landowners may drill wells and extract groundwater from an underlying aquifer for beneficial purposes, subject to management by the public.[77] Regulatory authority of groundwater lies with the Department of Natural Resources, which is required to develop groundwater management plans for both water quality and water quantity.

The Department of Natural Resources must conduct an annual assessment of the water balance in each watershed or sub-watershed in the state.[78] The Department also must classify each watershed as being under, fully, or over-appropriated based upon a set of criteria. All sources and uses of water must be measured or estimated, including both surface water and groundwater. In areas designated as "fully appropriated," new high-capacity wells and new surface water rights are banned. Nearly half the state has since been designated as fully appropriated or over-appropriated.[79]

---

[69] Monahan Cattle Co. v. Goodwin, 201 Neb. 845, 272 N.W.2d 774 (1978).
[70] Neb. Rev. Stat. 57-1602.
[71] Neb. Rev. Stat. 57-1604 (1).
[72] Neb. Rev. Stat. 57-1604 (2).
[73] Neb. Rev. Stat. 57-1604 (4).
[74] Neb. Rev. Stat. 46-202.
[75] Neb. Rev. Stat. 46-203.
[76] Regulations & Policies. University of Nebraska-Lincoln. Accessible at https://water.unl.edu/article/agricultural-irrigation/regulations-policies#:~:text=The%20water%20right%20issued%20by%20the%20Nebraska%20Department,document%29%20govern%20the%20use%20of%20Nebraska%20ground%20waters.
[77] Ibid.
[78] Ibid.
[79] Ibid.

Lithium Ownership and Extraction

Our research identified no Nebraska laws or regulations related to lithium extraction or the presence of lithium mines in the state.

OKLAHOMA

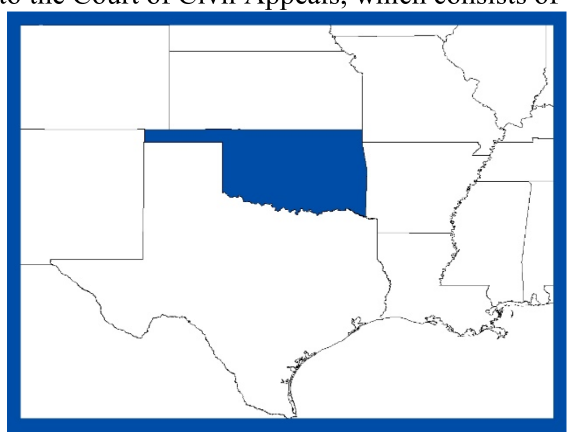
Executive Summary

Oklahoma, with a long history of oil and gas exploration, offers significant capacity to store CO_2 in saline formations and the oil and gas reservoirs of the Anadarko Basin. The state also has a network of CO_2 pipelines. The state's Carbon Capture and Geologic Sequestration Act establishes a permitting program for carbon sequestration activities but does not appear to significantly alter other, pre-existing, authorities. Oklahoma limits the ability of parties to exercise eminent domain and Oklahoma Courts have held that the mineral estate is considered the dominant estate.

Background

Oklahoma consists of federal, state, fee, and tribal lands. The state extends 683,289 acres, with 44,087,680 (1.5%) owned by the federal government.[1] This land is evenly dispersed throughout the state. In 2020, the US Supreme Court ruled that nearly half of Oklahoma falls within "Indian Country," which consists of 35 tribes and 27 reservations throughout the eastern half of the state.[2, 3] This means tribal law and federal law apply in these areas for criminal cases involving Native citizens, rather than state law. Roughly 25% of Oklahoma's recent oil and gas wells and 60% of its refinery capacity lie within the territory of five state tribes—the Cherokee, Chickasaw, Choctaw, Creek, and Seminole.[4] Oil and Gas Leasing for the Choctaw & Chickasaw Tribal Lands and Arkansas Riverbed Properties is governed by 25 CFR 211. Oil and gas leases can be negotiated pursuant to 25 CFR 211, section 211.20 "Leasing Procedures."

The Oklahoma court system operates under common law; it consists of 77 district courts, limited jurisdiction courts, the Court of Civil Appeals, and the Supreme Court.[5] The district courts hear the bulk of civil and criminal cases. Appeals for civil cases move to the Court of Civil Appeals, which consists of 5 judges, or the Supreme court, consisting of 9 justices. Oklahoma also has two courts of last resort—the Supreme Court for all civil cases, and the Oklahoma Court of Criminal Appeals for all criminal cases.[6]



The Oklahoma Corporation Commission (OCC), Oil and Gas Division is the state agency that oversees oil and gas production, Class II injection activities, and pipelines.

CCUS Activities in the State

Oklahoma has one of the nation's longest oil and gas histories, with the earliest discovery dating

[1] Federal Land Ownership: Overview and Data. (2020.) *Congressional Research Service.* Accessible at https://fas.org/sgp/crs/misc/R42346.pdf.

[2] Federal and State Recognized Tribes (2019). *National Conference of State Legislatures.* Accessible at https://www.ncsl.org/legislators-staff/legislators/quad-caucus/list-of-federal-and-state-recognized-tribes.aspx.

[3] History. *Mississippi Band of Choctaw Indians.* Accessible at https://www.choctaw.org/aboutMBCI/history/index.html.

[4] Supreme Court gives Oklahoma's Indian Tribes a Say over Oil Wells and Pipelines. *The Washington Post.* Accessible at https://www.washingtonpost.com/business/2020/07/17/supreme-court-oklahoma-oil-/

[5] Oklahoma Court System. Accessible at https://courtfacts.org/courtsystem/.

[6] Ibid.

back to 1859, when oil was found in present day Salina.[7] However, Oklahoma's oil and gas industry did not begin to boom until after the discovery of its first commercial producing oil well in 1897 near Bartlesville.[8]

Producing fields are scattered throughout Oklahoma, with some of the largest fields located in the western part of the state in the Anadarko Basin and shelf, also known as the STACK shale play, standing for Sooner Trend (shale formation), Anadarko (basin), Canadian and Kingfisher (counties). The other major basin is the Ardmore Basin, part of the South-Central Oklahoma Oil Province (SCOOP) play, which extends into parts of the Anadarko Basin in the north.[9, 10]

According to the U.S Energy Information Association, total oil production for 2020 was 171.7 million barrels, and total gas production in 2020 was 2,786,366 Mmcf (million cubic feet).[11] Annual oil production has averaged about 107.4 million barrels over the last 20 years.[12] As of August 2021, there are 46,711 producing oil and gas wells in Oklahoma[13] and over 2,163 oil fields, although 26 of these fields accounted for 59% of production.[14] According to US EPA data, there are over 11,000 Class II injection wells in Oklahoma, including 4,337 wastewater disposal wells, 6,688 EOR wells, and 58 wells used for other purposes, including hydrocarbon storage.[15, 16]

In 2018, CO_2 emissions for Oklahoma totaled 97.7 million metric tons, including 44.2 million metric tons from gas, 37.2 million metric tons from petroleum, and 16.4 million metric tons from coal.[17] According to a study conducted by the Great Plains Institute, there are 29 facilities that account for 85% of Oklahoma's CO_2 emissions that would likely qualify for a 45Q carbon tax credit. These facilities include 8 coal power plants, 7 gas power plants, and 3 refineries amongst other industries.[18] Additional sources of CO_2 in the state include ammonia facilities, chemical plants, hydrogen facilities, and gas processing plants.[19]

DOE estimates that a total of between 23.12 and 211.65 billion metric tons of CO_2 storage capacity are available in Oklahoma, primarily in saline formations (between 19.64 and 207.24 billion

[7] Dan Boyd. Oklahoma Geological Survey. Oklahoma Oil: Past, Present, and Future.
[8] Ibid.
[9] Ibid.
[10] Shale Experts. STACK and SCOOP Overview. Available at: https://www.shaleexperts.com/plays/stack-scoop/Overview/.
[11] US Energy Information Association. Oklahoma Natural Gas Gross Withdrawals and Production. Available at: https://www.eia.gov/.
[12] Ibid.
[13] Mineral Answers. Oklahoma Well and Production Data. Available at: https://www.mineralanswers.com/oklahoma.
[14] Dan Boyd. Oklahoma Geological Survey. Oklahoma Oil: Past, Present, and Future.
[15] EPA. UIC Injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.
[16] Department of Environmental Quality. Underground Injection Control (UIC) Permits. Available at: https://www.deq.ok.gov/land-protection-division/underground-injection-control/underground-injection-control-uic-permits/.
[17] US Energy Information Association. State CO2 Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.
[18] Great Plains Institute. Oklahoma: Implementing Carbon Capture and Storage Technology. Available at: https://carboncaptureready.betterenergy.org/wp-content/uploads/2020/08/OK_7_23_2020.pdf.
[19] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.

metric tons), followed by oil and gas reservoirs (3.48 to 4.40 billion metric tons), and unmineable coal storage (accounting for less than 0.01 billion metric tons).[20]

Much of the current research into CCUS is focused on injection of CO_2 from anthropogenic sources into depleted oil wells for EOR.[21] The Enid Fertilizer facility in Enid currently supplies CO_2 to depleted oil fields in the southern Anadarko Basin for EOR.[22] However, as part of research into CO_2-EOR in Oklahoma, the DOE created a "Conceptual CO_2 Pipeline System" which lays out paths connecting major depleted Oklahoma oil fields to the existing Enid Fertilizer pipeline.[23] There is also a stretch of CO_2 transmission pipeline, known as the TransPetco/Bravo, connecting the natural CO_2 sourced from the Bravo Dome in New Mexico to the Postle CO_2-EOR operation in western Oklahoma.[24] Other shorter CO_2 pipelines include the Borger pipeline, which transports CO_2 from the Agrium Fertilizer plant in Texas to Oklahoma for injection; the TexOk pipeline, which transports from the southern Kansas Arkalon Ethanol Plant through Oklahoma into Texas; and the Coffeyville Pipeline, which transports CO_2 from the Coffeyville Fertilizer Plant in Kansas to the Burbank field in Osage County, Oklahoma for injection.[25] The Burbank field is mostly located on the Osage Indian Reservation and extends to parts of Kay County.[26]

Classification of CO_2: Commodity

Oklahoma appears to classify CO_2 as a commodity. In 2003, the state established the Carbon Sequestration Certification Program under the Oklahoma Carbon Sequestration Enhancement Act,[27] which authorized the Oklahoma Conservation Commission to verify and certify carbon offsets for carbon credits, including injection of anthropogenic CO_2 for EOR.[28] The program was intended to help offset the impact of CO_2 emissions, but it was not fully developed until 2009 and has essentially laid dormant since 2014.[29] The state also passed the Oklahoma Carbon Capture and Geologic Sequestration Act in 2009, which declares CO_2 to be "a valuable commodity … particularly for its value in enhancing the recovery of oil and gas and for its use in other industrial and commercial processes and applications."[30]

In 2015, Governor Fallin issued an executive order that stated Oklahoma would not produce a state plan for upcoming federal rules regulating CO_2 from power plants.[31] At present, the state's Air Quality Division (which is responsible for monitoring outdoor air quality) only measures pollutants listed in the Federal Clean Air Act's pollution standards.

[20] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[21] USDOE. Basin Oriented Strategies for Co2 Enhanced Oil Recovery: Oklahoma. Available at: https://netl.doe.gov/sites/default/files/2021-03/Okl.pdf.
[22] CO2RE. Facilities. Available at: https://co2re.co/FacilityData.
[23] USDOE. Basin Oriented Strategies for Co2 Enhanced Oil Recovery: Oklahoma. Available at: https://netl.doe.gov/sites/default/files/2021-03/Okl.pdf.
[24] USDOE. A Review of the CO_2 Pipeline Infrastructure in the U.S.
[25] Ibid.
[26] The Encyclopedia of Oklahoma History and Culture. Burbank Field. Available at: https://www.okhistory.org/.
[27] Title 27A, Section 3-4-101.
[28] 27A O.S. § 3-4-101.
[29] Carbon Sequestration, Carbon Verification and the Oklahoma Carbon Program. (2020). *Oklahoma Farm Report.* Accessible at http://www.oklahomafarmreport.com/wire/news/2020/06/00001_CarbonSequestration06292020_103859.php#.YSz5J_eSk2w.
[30] Title 27A, Section 3-5-101.
[31] Oklahoma Governor Rules Out State Plan For EPA Carbon Pollution Rules. (2015). Times Record. Available at https://www.swtimes.com/article/20150430/NEWS/304309848.

Alongside the carbon credits program, the state hosts a gross production severance tax on monthly average crude oil and gas prices (with the exception of incremental production from secondary and tertiary enhanced recovery projects), as well as an additional excise tax and an Oil and Gas Production Fee – but seemingly only for natural gas and petroleum oil.[32]

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

CCUS-related activities are regulated by the Oklahoma Corporation Commission's Oil and Gas Division, which regulates oil and gas production, Class II injection activities, and pipelines. No tribal or local laws or regulations address CCUS-related activities within the state.

Pipeline Regulations

In Oklahoma, oil and gas and hazardous liquid pipelines are regulated by the OCC.[33] Okla. Admin. Code § 165:20-7-3 specifically grants the OCC authority over intrastate and interstate CO_2 pipelines.[34] Notice must be submitted to the OCC including "plans, specifications, maps, and other data relative to natural gas pipeline systems, underground natural gas storage facilities, and hazardous liquid pipeline systems" at least seven days prior to construction for any pipeline over one mile in length. [35, 36] Operators must also submit an annual report on US DOT Pipeline & Hazardous Materials Safety Administration's (PHMSA) Form F 7000-1.1 for each type of hazardous liquid facility operated at the end of the previous year. Regulations specific to transportation of oil and gas and hazardous liquids by pipeline are outlined in OAC 165:20-7-1 which directly reference 49 CFR Part 195.

Laws and Regulations for CO_2 Storage

The Oklahoma Carbon Capture and Geologic Sequestration Act, passed in 2009, authorizes a permitting program for CO_2 storage.[37] It gives the OCC authority over CO_2 sequestration into oil and gas reservoirs, coal-bed methane reservoirs, and mineral brine reservoirs, while the Department of Environmental Quality would have jurisdiction over CO_2 sequestration in all other reservoirs, including deep saline formations, unmineable coal seams, basalt reservoirs, salt domes, and non-mineral bearing shales. Our research did not identify rules of either Agency implementing this jurisdiction. Because Oklahoma has not been granted Class VI program primacy, any Class VI wells in Oklahoma would be subject to the federal Class VI Rule at 40 CFR 146.81 et seq and be overseen by US EPA Region 6.

Regulation of Oil and Gas Production

Oklahoma's requirements for oil and gas wells are found in Title 165, Chapter 5 and Chapter 10 of the Oklahoma Administrative Code.[38] The OCC Oil and Gas Conservation Division is responsible for the permitting and oversight of oil and gas wells in the state.

All oil and gas well operators must obtain an "environmental permit" from the OCC Oil and Gas Conservation Division prior to commencement of drilling, by filling out Form 1000.[39] Public notice must be posted within a newspaper of general circulation in Oklahoma County, OK and in a paper in each

---

[32] State Oil and Gas Severance Taxes. National Conference of State Legislatures. Accessible at https://www.ncsl.org/research/energy/oil-and-gas-severance-taxes.aspx.
[33] Okla. Admin. Code § 165:20-1-2.
[34] Okla. Admin. Code § 165:20-7-3.
[35] Okla. Admin. Code § 165:20-1-4.
[36] Okla. Admin. Code § 165:20-7-2.
[37] Title 27A, Section 3-5-101.
[38] OAC 165:5.
[39] 400-1-2-.01.

county represented in the application.[40] The information requested to be provided on Form 1000 includes: information about drilling direction, well location, lease owner and operator, target formations and depths, casing, pit information, plat information, and a plan for drilling fluid disposal.[41] An applicant must also provide a financial surety which may be a blanket surety of typically at least $25,000 or in the form of a financial statement demonstrating that the operator has a net worth of at least $50,000.[42]

Vertical oil and gas wells drilled into formations deeper than 2,500 feet must be more than 330 feet from any property or lease line, and more than 600 feet from any other producible well in the same source supply. Wells in shallower formations may not be located within 165 feet of any property or lease line and must be more than 300 feet from any other producible well in the same source supply.[43] Horizontal wells are subject to the same rules as above for the spacing of the completion and perforated intervals. Oklahoma Administrative Code notes that wells drilled as part of an enhanced recovery project may not be located within 165 feet of a lease or project line.[44]

The OCC also has the power to authorize pressure maintenance of a pool or oil production by injection of material into a common source, unitized or not, if it would yield substantial quantities of otherwise unrecoverable oil. The OCC may do so after notice and hearing of the operator's application. In the event of pressure maintenance authorized by the OCC, the well would be classified as either a Pressure Maintenance Project, Gas Repressuring Project, Waterflood Project, or Other Enhanced Recovery Project.[45]

Oklahoma is one of the only states with forced pooling for oil and gas exploration. Under §52-87.1e, applicants who are unable to form an agreement with the owners (such as mineral owners and lease holders) within the spacing unit regarding the method of developing the unit may apply to the OCC to have them "force pooled" into the unit. Force pooling allows working-interest owners to acquire the right to explore for oil and gas on lands where the owners either cannot come to terms with the offer, cannot be located, or are deceased. It should be noted that only formations that are spaced can be force pooled, and forced pooling does not apply to overriding royalty interests, restricted Indian minerals, or State-owned minerals.[46] The forced pooling process requires notice and a hearing.[47]

Section 1 of the Oklahoma Carbon Capture and Geologic Sequestration Act adds that, if the State establishes a unitization process to support the establishment of CO_2 sequestration facilities in this state, oversight authority would be granted to the OCC. This process does not appear to have been developed for CO_2 storage facilities yet.

Regulation of Injection Activities

Oklahoma has Class II UIC program primacy under Section 1425 of the SDWA, granted on December 2, 1981 to the Oklahoma Corporation Commission.[48] All other injection wells are overseen by the Oklahoma Department of Environmental Quality. The OCC oversees Class II wells via the Commission's Oil & Gas Division.

The rules for Class II injection wells are at Title 165: Corporation Commission Chapter 10: Oil and Gas Conservation; Subchapter 5; they were issued under the authority of Oklahoma Statutes Title 17

[40] OAC 165:5-7-6.
[41] OCC Oil and Gas Conservation Division. Form 1000.
[42] OAC 165:10-1.
[43] Ibid.
[44] OAC 165:10-1-26.
[45] OAC 165:10-15.
[46] The Pooling Process in Oklahoma. *Oklahoma Corporation Commission*. Accessible at https://oklahoma.gov/content/dam/ok/en/occ/documents/og/the-pooling-process-in-oklahoma.pdf.
[47] Okla. Admin. Code §52-87.1.
[48] 46FR58488.

and Title 52.[49] All new Class II wells must have a permit.[50] A permit application must be filed with the UIC Department on Form 1015[51] and be accompanied by a plat; a completion report; a schematic diagram; information about the injection and confining zones (including specific requirements for separation between the injection zone and USDWs based on planned injection rates); and proposed operating data. The applicant must also provide fresh water analyses, analyses of representative samples of Class II fluids to be injected, and electric or radioactivity logs and a financial surety. The applicant must also provide notice to each surface owner and surface lessee, as well as notice to the public.

Environmental Laws

The Oklahoma Administrative Code defines treatable water (which includes fresh water), and underground sources of drinking water. Treatable water is defined for the purposes of setting surface casing and other casing strings as, "subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides."[52]

An USDW is defined similar to the federal definition, as any portion of an aquifer which currently supplies or contains enough ground water to supply a public water system if the groundwater is currently used as drinking water or if the water contains less than 10,000 mg/l total dissolved solids and is not an exempted aquifer.[53]

To address the potential for injection-induced seismicity, the OCC amended its regulations in September 2014 to require operators injecting into the Arbuckle Formation to monitor and record injection volumes and pressures daily and provide the information to the Commission if requested. As part of its Class II permit application review process, the OCC requires and considers information about the proposed sites' seismic history and proximity to faults.[54]

The OCC has also begun to identify "areas of interest" for seismicity or "yellow light" areas, defined as those locations within 10 km of the epicenter of a 4.0 magnitude or greater earthquake, or within 10 km of the epicenters of two earthquakes located within a ¼ mile of each other where at least one of them was magnitude 3.0 or greater. Areas of interest also include all locations within three miles of a seismically active fault or any stressed fault.[55] Applications for permits in these areas undergo special review and operators may be required to reduce injection rates by 50 percent unless they are not drilling below the Arbuckle Formation.[56]

Under the Oklahoma Clean Air Act, cities, towns, and counties with populations above 300,000 may enact their own provisions for air quality if they are more stringent than the Oklahoma Clean Air Act standards. The Oklahoma Clean Air Act adopts the federal list of hazardous air pollutants established in Section 112 of the Federal Clean Air Act.[57]

---

[49] 17 OK Stat § 17-51 thru 53; 52 OK Stat § 52-86.1-86.5, 139-153, 243, 307-318.1.
[50] 165:10-5-2.
[51] 165:10-5-5.
[52] OAC 165:10-1.
[53] Ibid.
[54] Rocky Mountain Mineral Law Foundation. No date. Regulations Relevant to Injection-Induced Seismicity.
[55] Ibid.
[56] Ibid.
[57] OK Stat 27A Environment and Natural Resources.

Industrial Siting Requirements

Our research did not identify any statutes or regulations that govern the siting of oil and gas fields, pipelines, or energy utilities in Oklahoma.

Eminent Domain

Eminent Domain is outlined under the Oklahoma Constitution and under Oklahoma statute. Under Article 2, Section 23 of the Oklahoma Constitution, private property cannot be taken or damaged for private use, with or without compensation, unless by consent of the owner.[58] The exception is for "private ways of necessity, or for drains and ditches across lands of others for agricultural, mining, or sanitary purposes." Private property cannot be taken or damaged for public use without "just compensation."[59] It is up to the judiciary to determine the "character of the use" for all condemnation cases of private property, for both public and private uses.[60]

Generally, Oklahoma statute limits the ability of parties to exercise eminent domain and construct a gas pipeline or take private or public property unless otherwise specified in state statute.[61] So far, the state seems to have granted this right to include oil pipelines for transport of "petroleum, liquid or liquefiable hydrocarbons and chemicals" and natural gas pipelines (and designates them as common carriers), but not specifically for CO_2. Per Section 6, Part D of the Oklahoma Carbon Capture and Geologic Sequestration Act, nothing in the Act creates a right to use eminent domain for CCUS activities.[62] It is also unclear whether CO_2 pipelines would fall within either of the provisions for natural gas or oil pipelines.[63]

In general, state statute grants domestic pipeline companies in the state the right-of-way to "build, construct, lay and maintain oil pipelines over, under, across, or through all highways, bridges, streets or alleys" or any public place under the supervision of the Inspector of Oil and Gas Wells and Pipelines, but these oil carriers cannot be interested in producing. Additionally, all companies authorized by the Oklahoma Corporation Commission can exercise the right of eminent domain in the same manner as provided for railroad corporations.[64] Mineral estates cannot be seized through eminent domain proceedings without consent.[65]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Mineral rights in Oklahoma can be conveyed through a mineral deed or retained in a conveyance of the surface rights or be leased. These rights are considered to be real property and are held in either fee simple or absolute fee.[66, 67]

---

[58] OK Constitution, Article 2, Section 23.
[59] OK Constitution, Article 2, Section 23.
[60] Ibid.
[61] Okla. Admin. Code §52-3.
[62] Title 27A, Section 3-5-101.
[63] According to state statue, Oklahoma defines "natural gas" broadly as gas either while in its original state or after the same has been processed by removal therefrom of component parts not essential to its use for light and fuel (§52-36.1. (b)). Notably, it does not appear to be specific to methane and therefore may include CO_2.
[64] Okla. Admin. Code §52-46.3.
[65] Okla. Admin. Code §52-804.
[66] Okla. Admin. Code §60-5.
[67] Okla. Admin. Code §60-23.

Oklahoma operates under the "exclusive right to take" doctrine, meaning landowners do not actually own the substances under the land. Instead, mineral rights are considered "incorporeal" in that they represent a right to capture the minerals underlying a tract of real property, but the minerals themselves are not "owned" until they are captured.[68] The same applies to oil and gas leases – landowners do not own the subsurface oil or gas until they extract them from the ground and reduce them to possession.[69] However, Oklahoma's Carbon Capture and Geologic Sequestration Act states that ownership of CO_2 injected into a CO_2 sequestration facility lies with the facility owner.[70] In doing so, applicants must give all surface and mineral owners at least 15 days' notice of a hearing.[71]

Additionally, if mineral rights ownership cannot be established, the state of Oklahoma will give oil, gas, and petroleum companies permission to drill on the land. The Oklahoma Carbon Capture and Geologic Sequestration Act expressly states that nothing in the Act alters the ownership or other rights of the owners of the mineral estate.[72]

Mineral contracts in Oklahoma are interpreted in a way that gives effect to the "mutual intention" of the parties, which is ascertained from the writing alone.[73, 74] The words of a contract are to be understood in their ordinary sense instead of their legal meaning, unless they are being used by the parties in a technical sense or a special meaning is given to them by usage.[75] If the terms are ambiguous or uncertain, they must be interpreted in the way that the promisee understood it.[76]

Whether or not CO_2 is included in the term "minerals" would depend on the terminology used in the contract. As utilized in *Allen v. Farmers Union Co-operative Royalty Co*., Oklahoma Courts follow the doctrine of *ejusdem generis*, meaning when a contract uses general words that do not explain the specific terms preceding them, they only apply to the same kind of things specifically listed. In *Allen v. Farmers Union Co-operative Royalty Co*., for example, the courts determined that "all oil, gas & mineral rights" meant, "[O]il, gas and other minerals produced as a component or constituent thereof, whether hydrocarbon or nonhydrocarbon."[77]

According to Oklahoma statue, mineral estates cannot be taken via eminent domain proceedings without consent.[78]

Split Estates

Oklahoma landowners have the option of selling or leasing their mineral rights beneath the surface of their land. These rights can also be divided among multiple owners. Historically, Oklahoma Courts have held that the mineral estate is considered the dominant estate, and the surface estate the subservient.[79]

---

[68] Tilley, Marcia, and Willett, Delores. (2017.) Real Estate Ownership in Oklahoma. *Oklahoma State University, Division of Agricultural Sciences and Natural Resources.* Accessible at https://extension.okstate.edu/fact-sheets/print-publications/agec/real-estate-ownership-in-oklahoma-agec-784.pdf.

[69] Hogue, Joel R. (1984.) The Constitutionality of the Oklahoma Surface Damages Act. *Tulsa Law Review*. Accessible at https://digitalcommons.law.utulsa.edu/cgi/viewcontent.cgi?article=1686&context=tlr.

[70] Title 27A, Section 3-5-101 1, Section 5A.

[71] Title 27A, Section 3-5-101 1, Section 4D.

[72] Title 27A, Section 3-5-101 1, Section 6B.

[73] Okla. Admin. Code §15-152.

[74] Okla. Admin. Code §15-155.

[75] Okla. Admin. Code §15-160.

[76] Okla. Admin. Code §15-165.

[77] Allen v. Farmers Union Co-operative Royalty Co. 538 P.2d 204 (1975).

[78] Okla. Admin. Code §52-804.

[79] Hogue, Joel R. (1984.) The Constitutionality of the Oklahoma Surface Damages Act. *Tulsa Law Review.* Accessible at https://digitalcommons.law.utulsa.edu/cgi/viewcontent.cgi?article=1686&context=tlr.

Per the Exploration Rights Act of 2011, a surface owner must provide a reasonable right of access to the land so that the mineral rights owner can sever, capture, and produce the minerals.[80] At the same time, the Oklahoma Surface Damages Act requires that mineral owners or lessees engaged in drilling or preparing to drill for oil or gas must provide the surface owner a written notice of their intent before entering the surface lands, and they must negotiate with the landowner to determine and pay for any damage that would occur to their property as a result of their operations.[81] If these negotiations are not successful, the condemner can determine the damages through an appraisal or through jury trial.

Oklahoma does address abandoned mineral interests per state statute. However, Oklahoma statute states that proceeds or other intangible property interest from any mineral interests that are abandoned for at least 15 years will be subject to judicial sale by the state.[82]

Pore Space Ownership

The legislative and the judicial branches of Oklahoma have both decided that pore space ownership lies with the surface owner. In *Ellis v. Arkansas Louisiana Gas Company,* the federal district court argued that the surface owner of natural gas held the power to convey gas storage rights, arguing that hundreds of severed mineral interest owners would otherwise be contacted.[83] While this case only addressed pore space ownership of natural gas storage, Title 60 of Oklahoma Statutes, Section 6 later definitively stated that pore space in general is the property of the surface owner until title to it is separately transferred.

Water Rights

Since 1963, Oklahoma has been a prior appropriation state for surface water, which is subject to appropriation by the Oklahoma Water Resources Board (OWRB).[84] However, the state also utilized riparian rights prior to 1963, and such "vested" users are permitted to continue using their appropriated amounts.[85] There is no priority among uses of surface water as long as the uses are deemed beneficial and the date the OWRB receives an application is the priority date for the water permit.[86] The exception is in the event of a water shortage, in which domestic users have priority for surface water usage, followed by permittees according to their seniority.[87]

Access to the surface water requires a permit from the OWRB (with the exception being riparian landowners who use water for domestic use or diffuse water captured outside the cut bank of a definite stream.)[88] Allowable uses for water appropriations include mining, drilling of oil and gas wells, and oil and gas recovery.[89] In determining the amount of water available for direct diversions from a stream, the OWRB considers the mean annual precipitation run-off in the watershed above the point(s) of diversion, the mean annual flow, stream gauge measurements, domestic uses and all existing appropriations and

---

80 Okla. Admin. Code §52-803.

81 Okla. Admin. Code §52-318.3.

82 Okla. Admin. Code §84-271.1.

83 Ellis v Arkansas Louisiana Gas Company, 450 F. Sup 412 (N.D. Okla. 1978).

84 Stream Water Use. (2020). *Oklahoma Water Resources Board.* Accessible at https://www.owrb.ok.gov/supply/watuse/swwateruse.php.

85 M. D. Smolen, Aaron Mittelstet, Bekki Harjo (2017.) Whose Water Is It Anyway? Comparing the Water Rights Frameworks of Arkansas, Oklahoma, Texas, New Mexico, Georgia, Alabama, and Florida. *Oklahoma State University.* Accessible at https://extension.okstate.edu/fact-sheets/whose-water-is-it-anyway.html#oklahoma.

86 Ibid.

87 Ibid.

88 Ibid.

89 OK Adm. Code 785:20-1-5.(a).

other designated purposes in the stream system.[90] For a lake or reservoir, a determination of the amount of water available for appropriation is based on the 98 percent dependable yield for the reservoir for municipal and industrial use and 80 percent dependable yield for irrigation, based on stream flow records.[91]

Groundwater in Oklahoma is considered a private property right that belongs to the overlying surface owner[92] and any use other than domestic use requires a permit from the OWRB.[93] A permit may be issued if: the applicant owns or leases the land, the land overlies a fresh groundwater basin or subbasin, the proposed use is beneficial, and no waste by depletion or pollution will occur. According to the OWRB, each permit applicant is allotted two acre-feet/year per acre of land in basins where maximum annual yield studies have not yet been completed, and an amount more or less than that in basins where studies have determined how much water may be withdrawn.[94]

Groundwater withdrawal may also be limited by OWRB to allow each landowner a proportionate share.[95] If a hydrologic study has been done in the area, the permittee is allowed a proportionate share based on the amount that may be safely withdrawn, considering a minimum basin life of 20 years.[96] If the amount of water in a ground water basin has not been determined, temporary permits are issued, allowing withdrawal of up to 2 acre-feet per year per acre of land owned or leased by the applicant.[97]

Lithium Ownership and Extraction

Our research did not identify any Oklahoma state laws or regulations that address lithium extraction or mining. No information was identified about mines that produce lithium or extensive lithium deposits in Oklahoma.

---

[90] OK Adm. Code 785:20-5-5. (A1).

[91] OK Adm. Code 785:20-5-5. (B1).

[92] Groundwater Use. (2020). *Oklahoma Water Resources Board.* Accessible at https://www.owrb.ok.gov/supply/watuse/gwwateruse.php.

[93] Ibid.

[94] Ibid

[95] I M. D. Smolen, Aaron Mittelstet, Bekki Harjo (2017.) Whose Water Is It Anyway? Comparing the Water Rights Frameworks of Arkansas, Oklahoma, Texas, New Mexico, Georgia, Alabama, and Florida*. Oklahoma State University.* Accessible at https://extension.okstate.edu/fact-sheets/whose-water-is-it-anyway.html#oklahoma.

[96] Ibid.

[97] Ibid.

UTAH

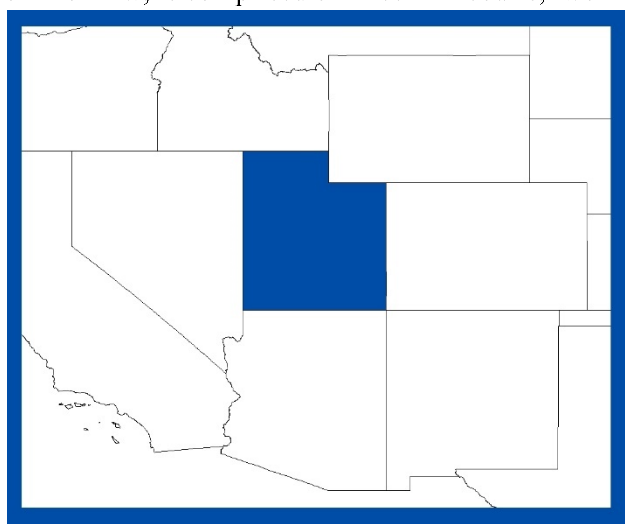
Executive Summary

Utah has CO_2 storage capacity in saline formations and in the oil fields in the northern, western, and southwestern parts of the state. CO_2 pipelines exist within the Rocky Mountain region, and research projects are focused along these routes. Recent legislation appears to signal a shift in focus towards reducing CO_2 emissions. While the state does not currently have regulations for CO_2 injection for storage, Utah's Rules for Carbon Capture and Geological Storage give the Divisions of Water Quality, Air Quality, and Oil, Gas, and Mining the authority to recommend rules for CCUS.

Background

Utah consists of federal, state, tribal and fee land. The state extends 52,696,960 acres, but the Federal government owns 63.1% of this land (or 33,267,621 acres) throughout the state.[1] The state is also home to 7 Native American tribes and 8 federally-recognized reservations, with no state-recognized reservations.[2]

Utah's judicial system, which operates under common law, is comprised of three trial courts, two appellate courts, and two administrative bodies.[3, 4] The trial courts include the District, Juvenile, and Justice Courts. The District Court includes 71 full-time district judges serving in the state's eight judicial districts. The appellate courts include the Court of Appeals, which consists of seven judges serving six-year renewable terms; and the Supreme Court, consisting of five justices who serve ten-year renewable terms.[5]



Utah state agencies that have jurisdiction over CCUS-related activities include the Utah Department of Natural Resources (UDNR) Division of Oil, Gas, and Mining (OGM) which regulates oil and gas production and Class II injection activities; and the Utah Public Service Commission Division of Public Utilities (DPU), which regulates pipelines.

[1] Federal Land Ownership: Overview and Data (2020). Congressional Research Service.

[2] Federal and State Recognized Tribes (2020). National Conference of State Legislatures. Accessible at https://www.ncsl.org/legislators-staff/legislators/quad-caucus/list-of-federal-and-state-recognized-tribes.aspx#State.

[3] Court Organization, Judges, Court Governance. *Utah Courts*. Accessible at https://www.utcourts.gov/knowcts/.

[4] The two judicial administrative bodies refer to the Utah Judiciary Council, the "policy-making body" for the judiciary; and the Administrative Office of the Courts serving as the staff to the Judicial Council.

[5] Ibid.

CCUS Activities in the State

The first reports of oil in Utah date back to 1890, when gold prospectors and residents found oil dripping from crevices in rocks around the Green River and Uinta Basin. However, commercial oil production and exploration did not begin until the early 1900s.[6]

Oil production in Utah is centered around the Uinta-Piceance and Paradox Basins, which are in western and southwestern Utah, and extend into Colorado.[7] There has also been substantial production in the thrust belt in northern Utah, extending into Wyoming.[8]

According to the U.S Energy Information Association, total oil production in Utah for 2020 was 30.9 million barrels[9] and total gas production in 2020 was 240,382 Mmcf (million cubic feet).[10] Annual oil production has averaged about 25.5 million barrels over the last 20 years and has been generally increasing since the early 2000's.[11] There are about 5,100 producing oil wells and 7,200 producing natural gas wells, across 153 active fields in the state.[12] According to US EPA data, there are 86 Class II wastewater disposal wells and 694 Class II EOR wells in Utah.[13]

In 2018, CO_2 emissions for Utah totaled 61.1 million metric tons of CO_2, including 26.1 million metric tons from coal, 21.6 million metric tons from petroleum, and 13.5 million metric tons from gas.[14] DOE estimates that a total of between 23.95 and 242.13 billion metric tons of CO_2 storage capacity are available in Utah—primarily in saline formations (which account for between 22.61 and 239.35 billion metric tons of this capacity), along with 1.31 to 2.66 billion metric tons in oil and gas reservoirs, and between 0.03 and 0.12 billion metric tons in unmineable coal storage.[15]

CCUS research in Utah focuses on naturally-sourced CO_2 and CO_2 from various stationary sources located near existing pipelines in the Rocky Mountain Region.[16] The McElmo Creek pipeline is a 40 mile long transmission line carrying CO_2 from the McElmo Dome in Colorado to the Aneth CO_2-EOR project in southwestern Utah. The McElmo Creek pipeline is connected to a much larger network of pipelines centered around Texas.[17] Another CO_2 pipeline extends from the Shute Creek in Wyoming, through the northeastern corner of Utah, into Colorado.[18]

Although research focuses on natural sources of CO_2,[19] the Great Plains Institute estimates that employing carbon capture technology at the state's seven major industrial and power facilities (including

---

[6] Utah History Encyclopedia. Petroleum. Available at: https://www.uen.org/utah_history_encyclopedia.
[7] Utah Geological Survey. Major Oil Plays in Utah and Vicinity. Available at: https://geology.utah.gov.
[8] Ibid.
[9] US Energy Information Association. Utah Crude Oil Production. Available at: https://www.eia.gov.
[10] US Energy Information Association. Utah Natural Gas Gross Withdrawals and Production. Available at: https://www.eia.gov.
[11] Ibid.
[12] Utah DNR OGM. Oil and Gas Field List. Available at: https://oilgas.ogm.utah.gov/oilgasweb/publications/publications-main.xhtml.
[13] EPA. UIC Injection Well Inventory. Available at: https://www.epa.gov/uic/uic-injection-well-inventory.
[14] US Energy Information Association. State Carbon Dioxide Emissions Data. Available at: https://www.eia.gov/environment/emissions/state/.
[15] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.
[16] Ibid.
[17] U.S. DOE. A Review of the CO_2 Pipeline Infrastructure in the U.S.
[18] USDOE. Basin Oriented Strategies for Co2 Enhanced Oil Recovery: Rocky Mountain Region.
[19] U.S. DOE. Carbon Storage Atlas – Fifth Edition (Atlas V) (2015). Available at: https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

four coal power plants and three cement manufacturing plants) could yield 19 million metric tons of captured CO_2 per year.[20, 21]

Classification of CO_2: Commodity and Pollutant

Within the past 10 years, Utah's Legislature has begun to pivot its stance on CO_2 emissions and climate change. For example, in 2010, the Legislature passed a resolution urging EPA to "immediately halt" its CO_2 reduction policies and programs until climate data and global warming science can be substantiated.[22] In 2020, conversely, the Legislature requested the University of Utah to develop a plan for the state to reduce emissions affecting the local air quality and the climate. The resulting "Utah Roadmap" included recommendations to reduce state CO_2 emissions to 25 percent below 2005 levels by 2025, to a 50 percent reduction by 2030, and 80 percent by 2050.[23]

While Utah does not currently list CO_2 as a pollutant,[24] the state has taken measures to reduce CO_2 emissions. The state's Municipal Electric Utility Carbon Emission Reduction Act mandates that 20 percent of energy sold consist of "qualifying electricity" or renewable energy certificates. This percentage may be reduced by the amount of electricity generated or purchased from qualifying zero carbon emissions generation or carbon sequestration generation.[25] Further, the state's Energy Resource Procurement Act requires that 20 percent of electricity supplied by utilities be low- or no-emission electricity (including via the use of carbon capture and storage) to the extent it is cost effective.[26]

Oil and gas are both subject to a severance tax under state law, with enhanced recovery projects receiving a 50 percent tax reduction.[27] In 2020, an attempt was made to include a Utah Carbon Tax Initiative on the 2020 ballot, but it did not gain enough signatures.

Regulation of CO_2 Pipelines, Geologic Storage, and CO_2-EOR

CCUS-related activities are regulated by the Utah Department of Natural Resources (UDNR) Division of Oil, Gas, and Mining (OGM) which regulates oil and gas production and Class II injection activities. Pipelines are regulated by the Utah Public Service Commission Division of Public Utilities (DPU).[28] No tribal or local laws or regulations address CCUS-related activities within the state.

---

[20] Great Plains Institute. Oklahoma: Jobs and Economic Impact of Carbon Capture Deployment. Available at: https://carboncaptureready.betterenergy.org/wp-content/uploads/2020/10/UT_Jobs.pdf.
[21] Great Plains Institute. Oklahoma: Implementing Carbon Capture and Storage Technology. Available at: https://carboncaptureready.betterenergy.org/wp-content/uploads/2020/08/UT_7_23_2020.pdf.
[22] H.J.R. 12 Climate Change Joint Resolution.
[23] The Utah Roadmap. (2020.) The University of Utah Kem. E. Gardner Policy Institute. Accessible at https://gardner.utah.edu/wp-content/uploads/TheUtahRoadmap-Feb2020.pdf?x71849.
[24] Aside from the 6 criteria pollutants EPA requires states to monitor, the only other pollutant that Utah considers "of interest" is wood smoke. Air Pollution and Public Health in Utah. Utah Department of Health. Accessible at https://health.utah.gov/utahair/pollutants/#Other.
[25] Utah Code Ann. § 10-19-101.
[26] Utah Code Ann. § 54-17-601.
[27] Utah Code Ann. § 59-5-102.
[28] Division of Public Utilities. Pipeline Safety Group. Available at: https://dpu.utah.gov/pipeline-safety.pdf.

Pipeline Regulations

DPU is responsible for the enforcement of regulations for pipelines used for the transport of natural gas or other flammable gases.[29] However, the state exempts CO_2 captured and transported for geologic sequestration from classification as a hazardous waste if the transportation of CO_2 complies with US DOT requirements and pipeline safety laws and regulations, and the CO_2 generator and the well operator certify that the CO_2 stream has not been mixed with hazardous wastes and is transported in compliance with US DOT requirements.[30] DPU rules adopt the minimum federal safety standards as described in CFR Title 49.[31] DPU rules contain additional provisions for inspections, reporting and notification requirements, written plans, and remedial action.[32]

Laws and Regulations for CO_2 Storage

The "Rules for Carbon Capture and Geological Storage" section of Title 54 of the Utah Code gives the Divisions of Water Quality, Air Quality, and OGM authority to recommend rules to the legislature in relation to carbon capture and geologic sequestration.[33] However, Utah has not been granted Class VI program primacy by EPA and has not developed rules for CO_2 injection for storage; therefore any Class VI wells in Utah would be subject to the federal Class VI Rule at 40 CFR 146.81 et seq and overseen by EPA Region 8.

Regulation of Oil and Gas Production

Oil and gas production in Utah is regulated by the OGM, with the applicable rules created by the Utah Board of Oil, Gas, and Mining.[34] OGM's responsibilities include the prevention of pollution of fresh water by oil, saltwater, or gas, including coalbed methane gas. Utah requirements for crude oil production are found in Utah Administrative Code Title R649, "Oil, Gas, and Mining" and Title 40, "Board and Division of Oil, Gas, and Mining."[35]

All operators seeking to drill, deepen, plug, or reenter any well, conduct exploratory drilling, or cause a surface disturbance associated with these activities must submit an application for a permit to drill (APD) and receive approval prior to drilling.[36] The APD must include: information on the owner, identification of all relevant oil and gas leases, a plat, a copy of approval from the Division of Water Rights, and a description of drilling plans including formation depths, a schematic diagram, and testing.[37] For directional or horizontal wells, the APD also requires a well diagram showing the path including the terminus of the lateral, its location within the target formation, a justification for the deviation, and written consent of all affected owners.[38] Prior to APD submission, the operator must also file a bond with the state, which is based on the well depth, and ranges from $1,500 for each well shallower than 1,000 feet to $60,000 for wells deeper than 10,000 feet.[39]

Unless subject to special orders, every vertical oil and gas well should be located within a 200-foot radius of the center of a quarter-quarter section (40 acres). Oil and gas wells may not be located

[29] Ibid.
[30] UAC 315-261-4(h)(4).
[31] UAC R746-409-1.
[32] Ibid.
[33] UT Code § 54-17-101.
[34] Intermountain Oil and Gas BMP Project. Utah Laws. Available at: http://www.oilandgasbmps.org/laws/utah_law.php#:~:text=Utah%20Oil%20and%20Gas%20Regulations%20The%20Division%20of,regulations%20governing%20oil%20and%20gas%20development%20in%20Utah.
[35] UAC R649.
[36] UAC R649-3-4.
[37] Ibid.
[38] Ibid.
[39] UAC R649-3-1.

within 920 feet of any other well producing or capable of producing from the same pool. The OGM may prescribe well pattern and siting of wells if the proposed unit is located next to an area where drilling units have been established, or if the proposed unit is adjacent to a unitized area where the pool extends beyond the boundaries of the unitized area or the drilling unit. In addition, no part of the horizontal interval of the producing formation may be less than 660 feet from a drilling or spacing unit boundary, federally unitized area boundary, uncommitted tract within a unit, or boundary line of a lease not committed to the drilling of a horizontal well. Horizontal wells' surface locations may be anywhere on the lease. In order to promote orderly development of the field, OGM rules establish a temporary 640-acre spacing unit encompassing the section where the horizontal well is located.[40]

Unitization of fields is determined to be appropriate if OGM finds that it is necessary to prevent waste and increase oil or gas recovery without increasing the cost of recovering the additional oil or gas.[41]

Regulation of Injection Activities

EPA granted Class II UIC program primacy under Section 1425 of the SDWA to the Utah Department of Natural Resources on October 8, 1982. Other classes of injection wells are overseen by the Utah Department of Environmental Quality.

The Rules and Regulations for Class II wells are in Title 649 of the Utah Administrative Code, issued under the authority of Title 40, Chapter 6 of the Utah Code Annotated. Class II permit applications must be provided on UIC Form 1 and be accompanied by: copies of electrical or radioactive logs; a cement bond or comparable log; a description of the fluid to be injected; proposed injection pressures; information to demonstrate the operation will not initiate fractures; and information on the injection and confining zones and USDWs. The applicant must also provide an affidavit that a copy of the application was provided to all operators, owners, and surface owners within one-half mile of the proposed injection well. Injection well permit applications are subject to public notice in a newspaper and a public hearing.

Environmental Laws

DEQ defines USDWs similar to the federal SDWA: as any portion of an aquifer which currently supplies or contains enough ground water to supply a public water system if the groundwater is currently used as drinking water or if the water contains less than 10,000 mg/l total dissolved solids and is not an exempted aquifer.[42] In accordance with DEQ rules for "Drinking Water Source Protection for Surface Water Sources," potential contamination sources which are subject to permit requirements or approval from the UIC Program are considered adequately controlled.[43]

Under the Utah Air Conservation Act, any source of air pollution requiring a permit under the federal Clean Air Act must also receive an operating permit from the Air Quality Board. Utah rules incorporate the federal emission standards for hazardous air pollutants for oil and natural gas production by reference. [44]

Our research did not identify any requirements or guidelines related to induced seismicity in Utah or concerns that this is an issue associated with injection activities.

---

[40] UAC R649-3-2.

[41] UAC 40-6-8.

[42] DEQ. Glossary: Utah Underground Injection control (UIC) Program. Available at: https://deq.utah.gov/water-quality/glossary-utah-underground-injection-control-uic-program.

[43] UAC R309-605.

[44] Intermountain Oil and Gas BMP Project. Utah Laws. Available at: http://www.oilandgasbmps.org/laws/utah_law.php#:~:text=Utah%20Oil%20and%20Gas%20Regulations%20The%20Division%20of,regulations%20governing%20oil%20and%20gas%20development%20in%20Utah.

Industrial Siting Requirements

The Utah Division of Water Quality required a general industrial storm water permit for construction of oil and gas facilities that would disturb more than one acre, until an exemption was granted to oil and gas facilities under the federal Energy Policy Act of 2005. This permit prescribes limitations on discharge location, effluent, and monitoring requirements. These facilities are now required to obtain a permit only if they are discharging contaminated storm water.[45]

Eminent Domain

Eminent domain is outlined in Utah statutes and in the Utah Constitution. Under Article I, Section 22, private property "shall not be taken or damaged for public use without just compensation."[46] Compensation is determined through a legal proceeding with a jury, based on the value of the property to be condemned, whether or not any or all of the property will be damaged through the taking.[47] To assess damages in partial takings, the courts must consider the market value of the property, which includes everything a willing buyer and a willing seller would consider in determining the market value of the property after the taking.[48]

Utah law authorizes the use of the power of eminent domain for public uses approved by the federal government or the state legislature, as well as "all other public uses for the benefit of any county, city, or town, or its inhabitants."[49] They also authorize eminent domain for "gas, oil or coal pipelines, tanks or reservoirs, including for underground natural gas storage facilities."[50] However, our research did not identify any rules or statutes specific to subsurface storage of CO_2.

Eminent Domain Procedure is outlined in Title 78B. Property can be taken for condemnation if it is determined that: the use is authorized by law; the taking is necessary; and the use will commence within a reasonable time as determined by the court.[51]

Land Use, Mineral, Water, and Pore Space Rights

Mineral Rights

Mineral rights in Utah are considered a type of real property that are held in fee simple title.[52] If there is more than one holder, title will be held as tenants in common.[53] Mineral rights can also be severed to create a mineral estate and a surface estate though a reservation of the mineral rights in a real estate conveyance; they can also be leased.

As mentioned earlier, the Federal government owns 63.1% of land in Utah. According to the Utah Geological Survey, almost all of this land is open to prospecting, with the exception of "National Parks, National Monuments, Indian Reservations, wildlife refuges, wilderness areas, military reservations, reclamation projects, or any other withdrawn areas."[54] This includes about 22.8 million acres of public

---

[45] Intermountain Oil and Gas BMP Project. Utah Laws. Available at: http://www.oilandgasbmps.org/laws/utah_law.php#:~:text=Utah%20Oil%20and%20Gas%20Regulations%20The%20Division%20of,regulations%20governing%20oil%20and%20gas%20development%20in%20Utah.
[46] Utah Constitution, Article 1 Section 22.
[47] Utah Code Ann. § 78B-6-511.
[48] Utah Code Ann. § 78B-6-511.
[49] Utah Code Ann. § 78B-6-501.
[50] Utah Code Ann. § 78B-6-501 (6d).
[51] Utah Code Ann. § 78B-6-504.
[52] Utah Code Ann. § 57-1-1 and Utah Code Ann. § 57-1-3.
[53] Utah Code Ann. § 57-1-5.
[54] Ege, Carl. (2000.) How Can I Stake a Mining Claim? *Utah Geological Survey.* Accessible at https://geology.utah.gov/map-pub/survey-notes/glad-you-asked/staking-a-mining-claim/.

lands, plus an additional 9.7 million acres of subsurface mineral estate lands, administered by the US Bureau of Land Management.[55] For state and trust lands, a mineral lease must first be obtained from the Utah School and Institutional Trust Lands Administration (SITLA).[56]

To interpret ambiguous mineral contracts, Utah courts will first examine other parts of the contract to see if there are provisions that can help define the ambiguous terms. If this does not help to define the language, Utah courts can turn to extrinsic evidence to determine what the intent of the parties was.

Whether CO_2 would be included in a "grant" of minerals would likely depend on the context in which it was used. In *Carrier v. Salt Lake County*, the Supreme Court examined a case involving the use of the phrase "mineral extraction" in a zoning ordinance and whether it encompassed gravel pit operations. In resolving the issue, the Court noted that the term mineral "is a word of general language, and [is] not per se a term of art."[57] Recognizing that "mineral" is ambiguous when read in isolation, the Court looked to its context in state statute and in other related statutes. Since Utah's Mined Land Reclamation Act explicitly excluded gravel from the definition of the term "mineral deposit" and from the definition of the term "mining operation," the Court held that the term "mineral extraction" did not encompass gravel pit operations.[58] It is unclear how CO_2 injection or CCUS activities might be interpreted in this context, however.

In a similar case, the Utah Supreme Court examined a case involving a plaintiff seeking to condemn a portion of land based on a state statute that permits eminent domain for the construction of roads to facilitate the working of "mineral deposits" and whether "mineral deposits" was meant to encompass oil and gas deposits.[59] In their ruling, the Court reasoned that the phrase "mineral deposits" was ambiguous because it could be understood to have two meanings: either including or excluding oil and gas.[60] Given this ambiguity and given that the Court "strictly construes an ambiguous statute purporting to grant the power of eminent domain against the condemning party," the plaintiff was therefore not authorized to condemn the land.[61]

Split Estates

Mineral rights in Utah can be severed from the surface to create two distinct estates: the mineral estate and the surface estate. When this occurs, the mineral estate is considered dominant to the surface estate.[62] Under the Utah Surface Owner Protection Act of 2012, which was designed to balance the rights of surface owners and oil and gas operators seeking mineral rights on private property, an operator may access the surface and use the land "to the extent reasonably necessary" to conduct oil and gas operations.[63] At the same time, they must minimize interference with the surface owner's use of the land,

---

[55] General Mining and Minerals Information. *U.S. Department of the Interior Bureau of Land Management.* Accessible at https://www.blm.gov/programs/energy-and-minerals/mining-and-minerals/about/utah#:~:text=The%20BLM%20Utah%20administers%20approximately%2022.8%20million%20acres,more%20different%20commodities%20than%20most%20other%20BLM%20states.
[56] Ibid.
[57] *Carrier v. Salt Lake County*, 104 p.3D 1208, 1216 (Utah 2014).
[58] Ibid.
[59] MARION ENERGY v. KFJ Ranch Partnership, 2011 UT 50, 267 P.3d 863.
[60] Ibid.
[61] Ibid.
[62] Guide to the Surface Owner Protection Act. (2012). *Utah Farm Bureau.* Accessible at https://www.duchesne.utah.gov/wp-content/uploads/planning/Guide_to_the_Surface_Owner_Protection_Act.pdf.
[63] Utah Code Ann. § 40-6-20 (1a).

so that the surface owner also can exercise the "greatest possible use of their property."[64, 65] In addition, the operator must compensate the surface owner for any loss of value or permanent damage to the surface land.[66] This Act applies in split estate properties between landowners and private or public companies; however, if the mineral rights are owned by any Indian Tribe or the federal government, Bureau of Land Management regulations apply.

Utah does not appear to have a provision for the expiration and reversion of mineral rights to the surface owner after a set number of years. There is, however, a provision for the Utah SITLA to administer unclaimed mineral interests and their proceeds.[67] In doing so, SITLA can either hold the property, sell it, or lease it to an operator to make use of the mineral interest.[68]

Pore Space Ownership

Our research did not yield any discussion of pore space ownership in Utah. It does not appear that the Legislative nor the Judicial branch has addressed whether the surface property owner or the mineral rights owner owns the pore space. The closest the state has come to defining this was in 2008, when they created a task force to "present recommended rules to the Legislature's Administrative Rules Review Committee discussing inter alia the ownership of subsurface rights and pore space."[69]

Water Rights

All waters in the state of Utah, including surface water and groundwater, are declared the property of the public.[70] Utah is a prior appropriation state in terms of acquiring water rights, and appropriations must be made for a "useful and beneficial purpose."[71] Among appropriators, the first in time is the first in right.[72] If there is a temporary water shortage, priority goes to drinking, sanitation, fire suppression, and agricultural purposes, including irrigation and livestock water.[73]

To obtain the right to appropriate water, applicants must file a permit application with the State Engineer.[74, 75] Approvals are granted based on consideration of: the nature and extent of the beneficial use; the priority date; the quantity of water to be diverted; the point and source of the diverted water; and the location of the beneficial use.[76, 77] Water rights can also be conveyed through a deed, as stated in Utah statute, and are transferred in the same manner as real estate.[78]

---

64 Utah Code Ann. § 40-6-20 (1b).

65 Utah Code Ann. § 40-6-20 (2b).

66 Utah Code Ann. § 40-6-20 (2c).

67 Utah Code Ann. § 75-2-105.

68 Smyth, Peter.(2019). Utah Clarifies Who is Entitled to Proceeds of Unclaimed Mineral Interests. Holland & Hart LLP. Accessible at https://www.theoilandgasreport.com/2019/03/15/__trashed/.

69 Utah Code Ann. § 54-17-701.

70 Utah Code Ann. § 73-1-1.

71 Utah Code Ann. § 73-3-1 (4).

72 Utah Code Ann. § 73-3-1 (5a).

73 Utah Code Ann. § 73-3-21.1 (2b), (2c).

74 Utah Code Ann. § 73-3-2.

75 The State Engineer is a specific role that is outlined in Utah statute that is appointed by the Governor with the consent of the Senate that serves for 4 years.

76 Utah Code Ann. § 73-4-5.

77 Water Rights Information. (2011). Utah Division of Water Rights. Accessible at https://www.waterrights.utah.gov/wrinfo/default.asp.

78 Utah Code Ann. § 73-1-10. (1a).

Additionally, water rights are subject to eminent domain, if the user provides compensation for the use and the use is exercised in a manner that does not impair the use of any other right of way or injure public or private property."[79]

Lithium Ownership and Extraction

Lithium production in Utah, specifically from surface or shallow subsurface brines, would most likely be sourced from the Great Salt Lake area or the Paradox Basin.[80] There is a current research effort underway to test the feasibility of extracting lithium from oil and gas wastewater brines that originated in deep geologic formations within the Paradox Basin. The Paradox Basin Brine Project is currently estimated to have 205,000 recoverable tons of lithium carbonate equivalent.[81]

The only Utah regulations identified in our research related to extraction of lithium via evaporation ponds, which is described in R649-9-4. The regulation addresses: the design and construction of evaporation facilities, quantity and chemistry of disposed water, and pond-liner specifications.[82]

---

[79] Utah Code Ann. § 73-1-6.

[80] Utah Geological Survey. Available at: https://geology.utah.gov/map-pub/survey-notes/energy-news/energy-news-increased-battery-demand-spurs-interest-in-utahs-metallic-resources/#:~:text=Lithium%20produced%20as%20a%20byproduct%20of%20magnesium%20recovery%2C,and%20shallow%20subsurface%20brines%20and%20salts%20in%20Utah.

[81] Ibid.

[82] Utah Code R649-9-4.