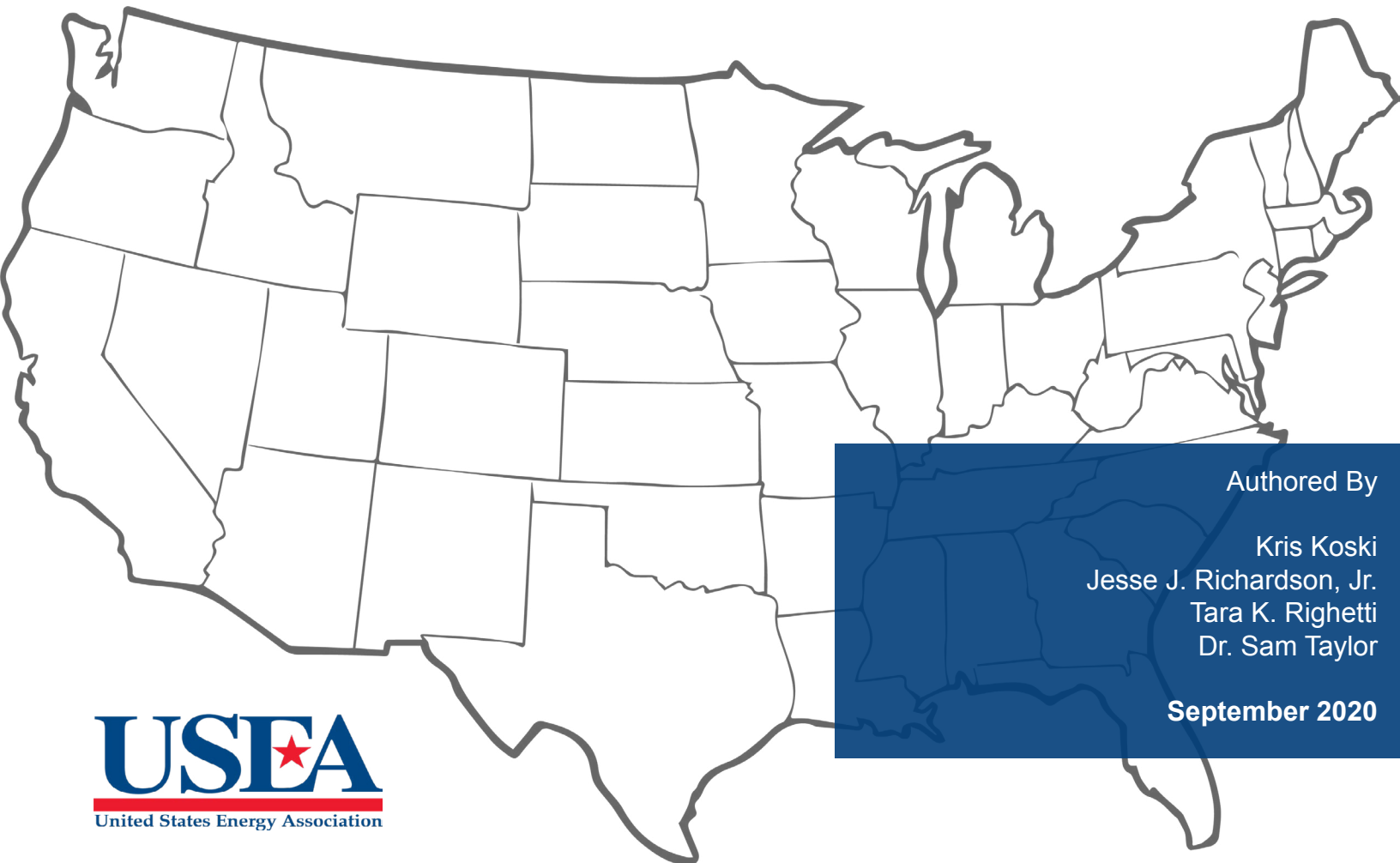


Study on States' Policies and Regulations per CO₂-EOR-Storage Conventional, ROZ and EOR in Shale:

Permitting, Infrastructure, Incentives, Royalty Owners, Eminent Domain, Mineral-Pore Space, and Storage Lease Issues



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**PROMOTING DOMESTIC AND INTERNATIONAL
CONSENSUS ON FOSSIL ENERGY TECHNOLOGIES**

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EXECUTIVE SUMMARY

This study evaluates laws, policies, and regulations governing CO₂-Enhanced Oil Recovery (“EOR”), associated CO₂ storage operations, and geologic storage across twelve states and onshore federal lands. This study principally includes two regions: the eastern region, comprised of the Illinois basin and the Marcellus shale region, and the western region, comprised of the Permian Basin and Rockies regions. In anticipation of expanded interest in CO₂-EOR, as a result of the amended 45Q tax credit and recently released draft treasury regulations, it is increasingly important for legislatures and policy makers to understand legal and regulatory challenges facing a more integrated and widespread implementation of CO₂ transportation, storage, and utilization. This project provides comprehensive and comparative analysis of four dimensions of CO₂ law, regulation, and policy: 1) land use, mineral, water, and pore space rights; 2) regulation of CO₂-EOR and CO₂ pipelines; 3) eminent domain; and, 4) geologic CO₂ storage and incremental storage regulation. The study suggests opportunities to harmonize energy policies and address regulatory gaps and inconsistencies. The aim of this study is to facilitate a better understanding of the legal underpinnings that frame risk, uncertainty, and investment in CO₂ utilization and storage infrastructure and projects, and to provide a roadmap for changes which are conducive to regional project development.

Most states have institutional capacity through state oil and gas regulatory agencies and existing regulatory frameworks for oil and gas, pipelines, and eminent domain. However, the study identifies three potential categories of constraints arising from state laws and policies: 1) regulatory gaps; 2) uncertainty regarding the application of existing oil and natural gas frameworks to CO₂ projects; and 3) interstate and state-federal inconsistencies and coordination issues, which present implementation challenges to regional projects. The study identifies opportunities for state lawmakers to address gaps and inconsistencies on a state-by-state basis, and opportunities for federal legislation and rulemaking. Moreover, the study concludes that, due to consistent institutions and relatively harmonized legal frameworks, regional coordination presents the most immediate opportunity for states to address implementation challenges.



INTRODUCTION

About this Study

In recent years, the United States has become the world's largest producer of both natural gas and oil. The Energy Information Administration ("EIA") reports that crude oil production reached a record-high average of 12.7 million barrels per day (bpd) in the first quarter of 2020, and dry natural gas production also reached a record high in November 2019, with production levels of 96.2 billion cubic feet per day (Bcf/d).¹ Concurrently, there is growing interest in carbon dioxide removal as a core component of the majority of pathways to decarbonization.² Carbon Capture and Sequestration ("CCS") and Carbon Capture, Utilization, and Sequestration ("CCUS") involve processes through which CO₂ is captured and injected underground for storage ("geologic storage").³ Although geologic storage projects have been proposed and enjoy wide federal support through grants and economic incentives such as 45Q, the majority of CO₂ storage today is attributable to CO₂-EOR. In this process, injection of CO₂ mobilizes oil stranded within the reservoir, thus increasing recovery of hydrocarbons while concurrently trapping some of the CO₂ underground in associated storage.⁴ Following conclusion of operations, the depleted reservoirs may be excellent candidates for further incremental CO₂ storage, temporary gas storage, or for permanent geologic sequestration. As a result, CO₂-EOR is a key technology for both additional hydrocarbon recovery and as part of decarbonization strategies.

Most aspects of CO₂-EOR are governed by state laws and policies. In some states, CO₂-EOR operations have been ongoing for decades, and many aspects of law and policy are clear. For instance, the right of a mineral owner or lessee to conduct CO₂-EOR operations as part of improved oil recovery is well established. This includes the right to inject fluid or gas into the property. In many states, courts privilege potential trespasses resulting from fluid migration under a doctrine called the "inverse rule of capture."⁵ However, as CO₂-EOR projects are evaluated in new and emerging areas, and as technology gains surpass state, federal, and tribal policies, significant barriers arise to deployment of advanced technologies due to regulatory uncertainty. Additionally, the rise in carbon capture and utilization approaches for industrial processes and for utilization in CO₂-EOR and CO₂ enhanced gas recovery ("CO₂-EGR") add additional regulatory and policy complications that may not have been considered to this point. For example, state laws may conflict on the permitting, mineral and pore space rights, and resource valuations, even though both CO₂ and petroleum resources may be produced in one state, transported through several other states, and utilized in formations that may underlie multiple states.

This project provides a state-by-state overview of laws, regulations, and policies applicable to CO₂-EOR; analysis of potential frictions that may arise regarding trans-boundary and interstate projects involving the production, capture, transportation, injection, and storage of CO₂; identification of regulatory barriers to the adoption of widespread CO₂ utilization; and recommendation for changes to facilitate large scale CCUS deployment in power generation and industrial processes. While a comprehensive evaluation and collection of state policies has its own value, this project intends to advance conversations regarding CO₂ storage and utilization through the identification of potential points of conflict and friction, and further identification of regulatory or policy options to overcome or remove these barriers.

"This project intends to advance conversations regarding CO₂ storage and utilization through the identification of potential points of conflict and friction, and further identification of regulatory or policy options to overcome or remove these barriers."

¹ U.S. ENERGY INFO. ADMIN., SHORT TERM ENERGY OUTLOOK SEPTEMBER 2020, 2-3 (2020).

² See James Hansen, *Young People's Burden: Requirement of Negative Emissions*, 8 EARTH SYSTEM DYNAMICS 577 (2017); International Energy Agency, *Carbon Capture and Storage: The Solution of Deep Emissions Reductions*, OECD/IEA (2015), available at <https://www.iea.org/publications/freepublications/publication/CarbonCaptureandStorageTheSolutionfordeepemissionsreductions.pdf>.

³ Rosa M. Cuellar-Franca & Adisa Azapagic, *Carbon Capture, Storage, and Utilization Technologies: A Critical Analysis and Comparison of Their Life Cycle Environmental Impacts*, 9 J. CO₂ UTILIZATION 82, 83 (2015).

⁴ Stephen L. Melzer, CARBON DIOXIDE ENHANCED OIL RECOVERY (CO₂ EOR): FACTORS INVOLVED IN ADDING CARBON CAPTURE, UTILIZATION AND STORAGE (CCUS) TO ENHANCED OIL RECOVERY 11 (Feb. 2012) (report prepared for the National Enhanced Oil Recovery Initiative, Center for Climate and Energy Solutions).

⁵ R.R. Comm'n of Texas v. Manziel, 361 S.W.2d 560 (Tex. 1962).

Content and Objectives

With the expected increase in interest prompted by the prospective use of 45Q tax credits, certainty regarding the security of CO₂ storage will be required for policymakers, investors, and regulators. It is necessary to understand the policies and regulations for CO₂ that is produced in one state, transported through several states via interstate pipelines, and injected as part of EOR in wells that may draw from oil reservoirs in more than one state. This study reviews and catalogs policies and regulations in selected states to determine the legal/regulatory framework currently in place and provide recommendations for changes to facilitate large-scale CCUS deployment for power generation and industrial processes. In addition, the study provides a more detailed view of local aspects of this emerging industry including permitting, infrastructure rights-of-way, production and disposal requirements, and more. This study provides an overview of the laws, policies, and regulations in each state, and summarizes the various surface/subsurface regulations pertinent to the management of CO₂ utilization and storage with maps and matrixes.

Regional Groupings

The first phase of this project examines laws, policies, and regulations regarding CO₂-EOR and carbon storage on onshore federal lands and in twelve states: Colorado, Illinois, Kentucky, Montana, New Mexico, North Dakota, Ohio, Pennsylvania, Tennessee, Texas, West Virginia, and Wyoming. The eastern region covers the Illinois basin and the Marcellus shale region, while the western region covers the Permian Basin and Rockies regions. These regions were chosen for this initial study in order to illustrate the key challenges and issues presented by laws, policies, and regulations between intra- and interregional states. Furthermore, the two regions facilitate contrast of implementation challenges associated with varying approaches to pipeline siting, water law, and land use patterns. The comparatively longer and more developed history of CO₂ utilization in the Permian and Rockies regions provides an opportunity to contrast its established regime with the emergent regulatory frameworks of the eastern region.

FEDERAL LAND

Summary

The Federal Government owns roughly 640 million acres, about 28% of the land in the United States.⁶ The majority of federal land is owned in fee, including both surface and minerals. In addition, the Federal Government owns various “split-estate” mineral interests underlying privately held surface interests. These split-estate mineral interests are typically reserved in land patents granted under various land disposition laws. Typically, the Federal Government also holds title to most of the tribal lands in trust for the benefit of the tribal populations.⁷

Federal lands must generally be managed for “multiple use” and “sustained yield.”⁸ The Federal Land Policy and Management Act (“FLPMA”) requires agencies to balance the resources and uses on the public lands to best serve present and future generations.⁹ Such uses include, but are not limited to, renewable and non-renewable energy development, recreation, grazing, timber harvest, and wildlife preservation.¹⁰ While a significant amount of federal land is offshore, this report does not address management for federal offshore minerals or holdings.

A significant portion of U.S. oil and gas production occurs on federal lands, with 24% of domestic oil production and 13% of natural gas production in 2017.¹¹ Seven western states, California, Colorado, New Mexico, North Dakota, Utah, Wyoming, and Texas, account for 96% of all federal onshore oil production and 88% of all federal onshore gas production.

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Ownership

Unless the lands were subsequently acquired under the Weeks Act and similar statutes, the Federal Government generally retains all surface and subsurface rights. In addition, the Federal Government owns various “split-estate” mineral interests underlying privately held surface in instances where the government reserved minerals in the patent.¹² Although the “hardrock” mining laws still technically allows for mining patents,¹³ federal mineral rights are generally not sold to private parties. Rights of access and use for federal lands are governed by a variety of statutes including the Agricultural Coal Lands Act, the Minerals Leasing Act (“MLA”), the Mining and Minerals Policy Act, the Federal Onshore Oil and Gas Leasing Reform Act (“FOOGLRA”), and the National Forest Management Act (“NFMA”). Additionally, the Federal Onshore Oil and Gas Leasing Reform Act of 1987 applies specifically to oil and gas development.

Oil, gas, coal, and certain other leasable minerals are leased for extraction on federal lands under various laws specifying their disposition, including the MLA.¹⁴ Where land has not been withdrawn for mineral development,¹⁵ federal oil and gas leases are issued pursuant to the MLA and consistent with environmental analysis and agency resource management plans.¹⁶ Oil and gas leases on federal lands are generally issued for a primary term of ten years through a competitive bidding process,¹⁷ but may be extended beyond the primary term by production.¹⁸ Federal oil and gas leases also include the right to produce CO₂, subject to royalties.¹⁹

⁶ C.H. VINCENT ET AL., CONG. RES. SERV., R42346, FEDERAL LAND OWNERSHIP: OVERVIEW AND DATA 1 (2020).

⁷ See *Worcester v. Georgia*, 31 U.S. 515 (1832) (finding the federal government was the sole authority to deal with Indian nations, which helped establish the doctrine of tribal sovereignty in the United States); *United States v. Mitchell*, 463 U.S. 206 (1983) (examining the trust relationship between the federal government and tribal nations and holding the government liable for damages following a breach of fiduciary duty); *Native American Ownership and Governance of Natural Resources*, OFFICE OF NATURAL RESOURCES REVENUE, U.S. DEP’T OF THE INTERIOR, <https://revenue.data.doi.gov/how-revenue-works/native-american-ownership-governance/> (last visited Sep. 9, 2020).

⁸ 43 U.S.C. § 1732(a) (2018).

⁹ *Id.*

¹⁰ U.S. DEP’T OF THE INTERIOR BUREAU OF LAND MGMT. AND OFFICE OF THE SOLICITOR, THE FEDERAL LAND POLICY AND MANAGEMENT ACT, AS AMENDED 69 (2001), <https://www.blm.gov/or/regulations/files/FLPMA.pdf>.

¹¹ MARC HUMPHRIES, CONG. RESEARCH SERV., R42432, U.S. CRUDE OIL AND NATURAL GAS PRODUCTION IN FEDERAL AND NONFEDERAL AREAS 2 (2014).

¹² See *Stock-Raising Homestead Act of 1916*, 43 U.S.C. §§ 291 *et seq.* (1976).

¹³ Since 1994, Congress has passed an annual moratorium on the issuance of patents under the General Mining Law of 1872. See *General Mining Act of 1872*, 30 U.S.C. § 22 (2018).

¹⁴ 30 U.S.C. §§ 181 *et seq.* (2020).

¹⁵ See *Nat’l Mining Ass’n v. Zinke*, 877 F.3d 845 (9th Cir. 2017), *cert. denied* 877 F.3d 845 (2018).

¹⁶ *What Informs Our Plans*, U.S. DEP’T OF THE INTERIOR BUREAU OF LAND MGMT., <https://www.blm.gov/programs/planning-and-nepa/what-informs-our-plans> (last visited Sept. 2, 2020).

¹⁷ 30 U.S.C. § 226(b)(1)(A) (2020); 43 C.F.R. § 3120.2-1 (2020).

¹⁸ 43 C.F.R. § 3107.2-1 (2020).

¹⁹ See *Aulston v. United States*, 823 F.2d 510 (Fed. Cir. 1987); *Enhanced Oil Recovery Using Carbon Dioxide, Oversight Hearing Before the Subcomm. on Energy and Mineral Resources of the H. Comm. on Natural Resources*, 110th Cong. 8–68 (2007) (statement of Tim Spisak, Division Chief, Fluid Minerals, Dep’t of the Interior Bureau of Land Mgmt.).

The Bureau of Land Management (“BLM”) is the agency responsible for managing most onshore mineral development CO₂-EOR on federal lands and minerals.²⁰ Such management includes coordination with other federal and state agencies. For instance, the BLM coordinates oil and gas activities within National Forests with the U.S. Forest Service within the Department of Agriculture.²¹ Whereas the mineral leasing act provides the BLM with authority to regulate minerals within National Forests, that same authority may not extend to the regulation of subsurface and pore space for carbon storage.

In contrast, “hardrock” minerals owned by the Federal Government are often subject to private “claim” location under the General Mining Act of 1872. To establish a mining claim for such hardrock minerals on federal lands, no lease is required; rather, the claimant must “discover” a valuable mineral deposit in compliance with the location requirements set forth in 43 C.F.R. §§ 3830.11 and 3830.12. Lithium is considered a “locatable mineral” under current interpretations of the General Mining Law of 1872²² regardless of whether it is mined on its own or found in a brine solution.²³ When found in a “mineral-bearing brine,” lithium is considered a placer claim for purposes of location on federal lands.²⁴

Split Estates

The Federal Government owns various portions of the mineral estate in roughly 57 million acres of split estate land across the United States.²⁵ The federal government has largely reserved these severed mineral estates under the Coal Land Acts,²⁶ the Agricultural Entry Act,²⁷ and the Stock-Raising Homestead Act of 1916 (“SRHA”).²⁸

Whether CO₂ is included within federally reserved minerals depends on the interpretation of the statute creating the reservation. When confronted with the issue in the late twentieth century, the Department of Interior determined that CO₂ had been reserved to the federal government under the Agricultural Entry Act of 1914

²⁰ *About the BLM Oil and Gas Program*, U.S. DEP’T OF THE INTERIOR BUREAU OF LAND MGMT., <https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/about> (last visited Aug. 27, 2020).

²¹ 36 C.F.R. §§ 228.110 *et seq.* (2020).

²² *See Clayton Valley Minerals, L.L.C.*, 186 IBLA 1, 4 n.7 (2015).

²³ 43 C.F.R. § 3832.21(b)(3)(iv) (2020).

²⁴ *Id.*

²⁵ *How Revenue Works, Split Ownership*, U.S. DEP’T OF THE INTERIOR NAT. RES. REVENUE DATA, <https://revenue.data.doi.gov/how-revenue-works/ownership/> (last visited Aug. 27, 2020).

²⁶ 30 U.S.C. §§ 81, 83–85 (2018).

²⁷ Agricultural Entry Act, ch. 142, 38 Stat. 509 (1914) (current version at 30 U.S.C. §§ 121 *et seq.* (2020)).

²⁸ Stock-Raising Homestead Act, ch. 9, 39 Stat. 862 (1916) (current version at 43 U.S.C. § 299 (2020)).

²⁹ *Aulston v. United States*, 915 F.2d 584 (10th Cir. 1990).

³⁰ *Id.*

³¹ *See Watt v. W. Nuclear, Inc.*, 462 U.S. 36 (1983).

³² *See Amoco Prod. Co. v. S. Ute Tribe*, 526 U.S. 865 (1999).

³³ *See* 43 C.F.R. § 3101.1-2 (2020); *Leasing and Development of Split Estate*, U.S. DEP’T OF THE INTERIOR BUREAU OF LAND MGMT., <https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/leasing/split-estate> (last visited Sept. 2, 2020).

³⁴ *See Entek GRB, L.L.C. v. Stull Ranches, L.L.C.*, 763 F.3d 1252 (10th Cir. 2014) (“Entek I”).

³⁵ DEP’T OF THE INTERIOR BUREAU OF LAND MGMT. & U.S. FOREST SERVICE, SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT: THE GOLD BOOK 12 (4th ed. 2007).

“Whereas the mineral leasing act provides the BLM with authority to regulate minerals within National Forests, that same authority may not extend to the regulation of subsurface and pore space for carbon storage.”

because CO₂ fits within the meaning of the word “gas” as used in the statutes.²⁹ When challenged by private surface owners, the United States Court of Appeals for the Tenth Circuit confirmed this interpretation in *Aulston v. U.S.*³⁰ In general, federal mineral reservations are often interpreted broadly to reserve the largest possible estate.³¹ As a result, similar reservations under the SRHA would likely be found to include CO₂. In contrast, precedent in *Amoco Production Co. v. Southern Ute Tribe* suggests that CO₂ was likely not included in federal coal reserved under the Coal Lands Acts.³² However, the federal coal reservation issue has not been directly considered by courts.

Like most private land ownership under state laws, a severed surface estate is servient to federally owned minerals.³³ Federal mineral reservations expressly reserve the right to enter and use the surface for disposition of the minerals. These reserved rights are interpreted broadly, allowing the use of the surface in unitized or communitized lands.³⁴

Although there is no federal surface damage or split estate statute, BLM regulations and policy further limit the dominant nature of the federally owned mineral estate, giving split estate surface owners many of the same protections extended under state laws.³⁵ The BLM requires notice prior to operations, good faith negotiation with a surface owner to reach a surface use agreement,

and surface reclamation.³⁶ Where parties are unsuccessful at negotiating an agreement, the developer may proceed with operations after posting a bond to cover potential damage to the surface estate.³⁷ It is unclear to what extent, if any, state surface protection laws apply to land with federally owned split-estate minerals. In a past dispute, the State of Wyoming and the BLM took opposing views as to the applicability of Wyoming's split estate statute on lands with federal mineral ownership;³⁸ however, in Wyoming, operators customarily comply with both state and federal split-estate laws and regulations.

Where the federal government owns split-estate surface interests overlying private minerals, the federal government generally may not use environmental protection and land policy statutes to prevent private mineral owners from developing their resources.³⁹ For example, in *Minard Run Oil Co. v. U.S. Forest Service*, the Third Circuit held that the U.S. Forest Service could not require environmental impact studies prior to the operator commencing drilling activities.⁴⁰ The court reasoned that a mineral owner has a right to use as much surface land as is reasonably necessary to extract the minerals, without further National Environmental Policy Act ("NEPA") requirements, under applicable Pennsylvania state law.⁴¹ Although the Federal Government was entitled to notice prior to entry under state law, the mineral owners did not need approval, permission, or additional studies from the federal government prior to entering onto the surface.⁴²

Pore Space Ownership and Storage Rights

Pore space is defined as the voids within rocks and geologic formations that are unoccupied by other material. Where federal land is owned in fee, rights in the pore space are also federally owned. The question of federal or private ownership of pore space in split estate lands is more complex. The issue is unique to each individual statute which may have disposed of the surface, such as the Homestead Acts, or acquired the surface through statutes like the Weeks Act. These federal statutes, if construed to cover the topic of pore space ownership,

³⁶ See U.S. DEP'T OF THE INTERIOR BUREAU OF LAND MGMT., INSTRUCTION MEMORANDUM No. 2003-131 (IM 2003-131): PERMITTING OIL AND GAS ON SPLIT ESTATE LANDS AND GUIDANCE FOR ONSHORE OIL AND GAS ORDER No. 1.

³⁷ *Id.*

³⁸ *BLM Disputes Wyoming Split Estate Law*, BILLINGS GAZETTE (June 21, 2005), https://billingsgazette.com/news/state-and-regional/wyoming/blm-disputes-wyoming-split-estate-law/article_a0cf3fe8-0011-56a4-8fed-d4112c3d8dd3.htm.

³⁹ See *Minard Run Oil Co. v. U.S. Forest Serv.*, 670 F.3d 236 (3d Cir. 2011), *as amended* (Mar. 7, 2012); *but see* *Duncan Energy Company v. U.S. Forest Serv.*, 50 F.3d 584 (8th Cir. 1995).

⁴⁰ *Id.*

⁴¹ *Id.* at 243–44.

⁴² *Id.* at 254.

would likely preempt state legislative declarations of pore space ownership. While there is no definitive guidance on the issue, judicial decisions interpreting the SRHA may be construed to address the issue of ownership and use of pore space for split-estate lands with federally owned minerals.⁴³ In *Watt v. Western Nuclear, Inc.* the Supreme Court of the United States held that land grants should be construed in favor of the government and only allow rights to be conveyed by express language, and no transfers of rights by implication.⁴⁴ *Watt* outlined a four-part test for determining if a right is within the scope of the SRHA, requiring that the substance (1) be mineral in character, (2) be removable from the soil, (3) be amendable to use for commercial purposes, and (4) that there be no reason to suppose the substance was intended to be included in the surface estate.⁴⁵ *Watt* was partly based on a case from the Ninth Circuit, *United States v. Union Oil Co. of California*,⁴⁶ which held that mineral reservations under the SRHA include geothermal resources.⁴⁷ The applicability of these cases to pore space for geologic storage is limited, as both involved use of substances associated with energy production (gravel in *Watt* and geothermal in *Union Oil*). In each case, the court found that the substances were included within the federally reserved mineral estate based on legislative history and purpose to determine the intent of federal mineral reservations, which championed energy production.⁴⁸

While these cases indicate that a mineral reservation under the SHRA will be construed broadly according to the purposes of the statute, neither case expressly addressed the issue of pore space. Relying on this precedent, at least one set of commentators concluded that the federal government likely owns the pore space beneath split-estate lands with federal mineral ownership.⁴⁹ However, another commentator recently concluded the opposite, arguing that state law is likely to determine the issue of pore space ownership in such split-estate scenarios based on various United States Supreme Court decisions that deferred to state law when answering property ownership questions.⁵⁰ Accordingly,

⁴³ 43 U.S.C. § 299 (2018).

⁴⁴ *Watt v. W. Nuclear, Inc.*, 462 U.S. 36, 59 (1983).

⁴⁵ *Id.* at 53.

⁴⁶ 549 F.2d 1271 (9th Cir. 1977).

⁴⁷ *Id.* at 1280.

⁴⁸ *Id.* at 1279.

⁴⁹ Kevin L. Doran & Angela M. Cifor, *Does the Federal Government Own the Pore Space Under Private Lands in the West? Implications of the Stock-Raising Homestead Act of 1916 for Geologic Storage of Carbon Dioxide*, 42 ENVTL. L. 527, 531 (2012).

⁵⁰ Stefanie L. Burt, *Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions*, 4 JOULE DUQ. ENERGY & ENVTL. L. J. (2016) <http://www.duqlawblogs.org/joule/wp-content/uploads/2016/07/Who-Owns-the-Right-to-Store-Gas-A-Survey-of-Pore-Space-Ownership-in-U.S.-Jurisdictions-.pdf>.

this fundamental issue of pore space ownership within split estates remains unresolved.

Use of federal pore space for injection operations is well established, although it is unclear the extent to which regulations and guidance regarding injection easements would apply for geologic storage operations. Although there are currently no specific regulations pertaining to the disposition of federal pore space for purposes of geologic CO₂ storage, expired guidance from the BLM indicates that such use rights could possibly be obtained pursuant to a land use permit, lease or easement under FLPMA's permitting process and consistent with 43 C.F.R. § 2920.1-1(b).⁵¹ However, the lack of current guidance on procedures or rules regarding utilization of federal pore space for geologic storage creates regulatory uncertainty and may be an obstacle to greater federal pore space utilization.

Overall, the lack of clarity regarding ownership of pore space under the various land disposition laws, the extent of rights granted in pore space under mineral leases, and processes for obtaining use rights in federal pore space add uncertainty to projects that include federal lands, increasing potential cost and risk.

Water Rights

In general, state law determines water use rights and priority. However, the federal government influences water use in several significant ways. Most importantly, federal reserved water rights, such as those reserved to Native American tribes or those reserved to the federal government to protect the purpose(s) for which the federal reservation/monument was created, exist separately from, and are superior to, state water rights created after the establishment of such land reservation.⁵² Specifically, when the federal government withdraws land for a specific federal purpose, the government, by implication, may acquire “appurtenant water then unappropriated to the extent needed to accomplish the purpose of reservation.”⁵³ This doctrine may limit the availability of water for state appropriations, as federal reserved water rights have priority over state water rights acquired after the date of the reservation.⁵⁴

⁵¹ See U.S. DEP'T OF THE INTERIOR BUREAU OF LAND MGMT., INSTRUCTION MEMORANDUM NO. 2012-035, INTERIM GUIDANCE ON EXPLORATION AND SITE CHARACTERIZATION FOR POTENTIAL CARBON DIOXIDE GEOLOGIC SEQUESTRATION (2011).

⁵² See *Winters v. United States*, 207 U.S. 564 (1908); *Cappaert v. United States*, 426 U.S. 128 (1976). The federal reserved water rights doctrine is often called the *Winters Doctrine*.

⁵³ *Cappaert*, 426 U.S. at 138.

⁵⁴ *Id.*

In addition, federal environmental statutes, such as the Endangered Species Act (“ESA”) and the Clean Water Act (“CWA”), can influence the availability and use of water resources. The ESA is triggered if the use, consumption, or disposal of water could threaten, harm, or cause jeopardy to any listed species.⁵⁵ The CWA precludes “the discharge of any pollutant” into navigable waters from any point source.⁵⁶

Tribal Lands

Mineral leases and development on tribal lands are governed by the Indian Mineral Leasing Act of 1938⁵⁷ and the Indian Mineral Development Act of 1982.⁵⁸ The Bureau of Indian Affairs (“BIA”) maintains regulatory authority over tribal land leases.⁵⁹ The BLM primarily regulates oil and gas development on tribal lands but works in conjunction with the BIA.⁶⁰ Determining ownership of minerals and pore space on tribal land may require an examination of treaties and laws regarding the tribal land and any subsequent conveyances.

Multiple Mineral Development

Competing energy and mineral development may impact the feasibility of CO₂-EOR and storage projects. A recent dispute between Peabody Energy (coal producer) and Berenergy, Inc. (oil and gas producer) in Wyoming's Powder River Basin provides some insight into resolutions of multiple mineral conflicts on federal land.⁶¹ Berenergy is the operator of oil and gas wells on federal oil and gas leases dating back to the 1960s, while Peabody is an area coal producer holding subsequently issued federal coal leases covering the same lands.⁶² In an August 2018 decision letter, the BLM ruled that it had statutory authority under the MLA to suspend mineral leases (and development thereunder) to allow production of coal mining to continue based on the value of the coal relative to the oil.⁶³ The Wyoming District Court upheld the BLM's authority under the MLA to suspend the federal oil and gas leases under 30 U.S.C. § 209. It found that weighing the comparable value of the coal to the oil and gas that could be recovered was a sufficient basis for the BLM's decision and that the BLM is not bound

⁵⁵ *Berenergy Corp. v. BLM*, et al., No. 19-8041, 2019 WL 3543401.

⁵⁶ See 33 U.S.C. § 1311 (2018).

⁵⁷ Indian Mineral Leasing Act, 25 U.S.C. §§ 396a *et seq.* (2018).

⁵⁸ Indian Mineral Development Act, 25 U.S.C. §§ 2101–2108 (2018).

⁵⁹ 25 C.F.R. §§ 211.1–211.58 (2020); 25 C.F.R. §§ 200.1–227.30 (2020).

⁶⁰ 25 C.F.R. §§ 216, 225 (2020).

⁶¹ See *Berenergy Corp. v. Bureau of Land Mgmt.*, Case No. 18-CV-158-SWS, (D.Wyo. May 13, 2019) *order upholding in part and reversing in part*.

⁶² *Id.*

⁶³ *Id.*

to any “first-in-time, first-in-right” determinations.⁶⁴ On June 11, 2019, Berenergy initially appealed the decision to the Tenth Circuit Court of Appeals, but the Court later dismissed the case in September 2019 at its request.⁶⁵ Based upon the Wyoming District Court ruling, it appears that the BLM has broad authority under the MLA to suspend mineral development operations where it may not be feasible for simultaneous multiple energy and mineral development.

Eminent Domain:

The federal government maintains extensive eminent domain power through acts of Congress, as set forth in numerous cases.⁶⁶ At this time, however, no specific federal statutory authorization exists for condemnation of land for CO₂ pipelines or CO₂ storage on private land. United States Supreme Court precedent indicates that the federal government holds the authority to condemn water and water rights.⁶⁷

Regulation for CO₂-EOR and CO₂ Pipelines:

Federal Oil and Gas Permitting

The BLM manages mineral development on federal lands and federal mineral holdings, including oil and gas operations, under the MLA and the FLPMA.⁶⁸ The FLPMA requires the BLM to manage public lands “under the principles of multiple use and sustained yield,”⁶⁹ ensuring environmental preservation and protection.⁷⁰ The BLM also regulates oil and gas development on federal land under Title 43 of the Code of Federal Regulations, Parts 3100 to 3190 and Onshore Oil and Gas Orders.⁷¹

⁶⁴ *Id.*

⁶⁵ See *Berenergy Corp. v. Bureau of Land Mgmt.*, Case No. 19-8041, U.S. Court of Appeals, Tenth Circuit.

⁶⁶ See generally, *Kohl v. United States*, 91 U.S. 367, 374 (1876).; *Chappell v. United States*, 160 U.S. 499, 510 (1896).; *California v. Cent. Pac. R.R.*, 127 U.S. 1, 39 (1888) (highways); *Luxton v. N. River Bridge Co.*, 153 U.S. 525 (1894) (interstate bridges); *Cherokee Nation v. Southern Kansas Ry*, 135 U.S. 641 (1890) (railroads); *Albert Hanson Lumber Co. v. United States*, 261 U.S. 581 (1923) (canals); *Ashwander v. TVA*, 297 U.S. 288 (1936) (hydroelectric power). *Berman v. Parker*, 348 U.S. 26, 33 (1954) (stating “[o]nce the object is within the authority of Congress, the right to realize it through the exercise of eminent domain is clear. For the power of eminent domain is merely the means to the end.”).

⁶⁷ See generally *Int’l Paper Co. v. United States*, 282 U.S. 399 (1931); *United States v. Gerlach Livestock Co.*, 339 U.S. 725 (1950); *Dugan v. Rank*, 372 U.S. 609 (1963).

⁶⁸ Federal Land Policy and Management Act of 1976 (Bureau of Land Management Organic Act) (FLPMA), Pub.L. 94-579, 90 Stat. 2743 (codified as amended at 43 U.S.C. §§ 1701 *et seq.* (2018)); Mineral Leasing Act, 30 U.S.C. §§ 181 *et seq.* (2018).

⁶⁹ 43 U.S.C. § 1732(a) (2018).

⁷⁰ 43 U.S.C. § 1701(a)(8) (2018).

⁷¹ 43 C.F.R. § 3164.1 (2020).

The BLM regulates drilling, production, plugging, and abandonment of wells, and enforces state spacing rules on federal lands.⁷² Prior to beginning drilling activities on a federal leasehold, an oil and gas operator must apply for a separate permit to drill for each well and post a bond to guarantee “compliance with all the terms and condition of the entire leasehold(s)[.]”⁷³ After allowing 30 days for “public inspection” of the proposed operations, the BLM may permit the operation if it approves the drilling and surface use plans and evidence of bond is sufficient.⁷⁴ Operators must conduct all activities in a manner that safeguards life, property, the environment, and other natural resources, while ensuring maximum oil and gas recovery.⁷⁵

When a federal oil and gas lease is incapable of economic development compliant with state spacing requirements, the leasehold owner may request a communitization agreement from the BLM.⁷⁶ Communitization forms the federal equivalent of pooling agreements on private land.⁷⁷ A communitization agreement may include other federal leaseholds as well as privately owned tracts,⁷⁸ and must outline the production allocation method to be used.⁷⁹ A communitization agreement will only be effective on the federal leasehold upon approval by the BLM.⁸⁰ In addition, the MLA authorizes the unitization of federal, fee, and state leases for unit- or field-wide development such as for CO₂-EOR operations.⁸¹ Upon the commitment of federal leases to the unit, the federal leases “conform” to the terms and provisions of the unit agreement.⁸² State law impacts federal EOR units, because state law may provide a path to compulsorily join working interest and royalty-owning parties that may otherwise be unwilling to join the federal EOR unit.⁸³

⁷² 43 C.F.R. §§ 3162.1–3162.7 (2020).

⁷³ 43 C.F.R. §§ 3104.1(a), 3162.3-1 (2020).

⁷⁴ 43 C.F.R. § 3162.3 (2020).

⁷⁵ 43 C.F.R. § 3162.1 (2020).

⁷⁶ 30 U.S.C. § 226(m) (2018).

⁷⁷ 43 C.F.R. §§ 3105.1–3105.6 (2020).

⁷⁸ 43 C.F.R. § 3105.2-2 (2020).

⁷⁹ 43 C.F.R. § 3105.2-3(a) (2020).

⁸⁰ 43 C.F.R. § 3105.2-3(b) (2020).

⁸¹ 30 U.S.C. § 226(m) (2020); see also 43 C.F.R. §§ 3180 *et seq.* (2020).

⁸² 30 U.S.C. § 226(m) (2020).

⁸³ See Craig Newman, *Secondary Recovery Units, Pressure Maintenance and Recycling*, 43B ROCKY Mtn. MIN’L L. Fdn. 10 (1997). But see Aulston, *supra* note 29 (regarding inability to compulsorily unitize the interest of the United States).

Pipeline Regulation

The U.S. Department of Transportation (“USDOT”) regulates natural gas and hazardous material pipeline safety through the Pipeline and Hazardous Material Safety Administration (“PHMSA”).⁸⁴ Through its Office of Pipeline Safety (OPS), PHMSA regulates CO₂ pipeline safety under the Hazardous Liquid Pipeline Safety Act.⁸⁵ OPS regulations govern CO₂ pipeline design, construction, pressure, and maintenance.⁸⁶

There is currently no federal siting authority for CO₂ pipelines except on federal land. The Federal Energy Regulatory Commission (“FERC”) regulates the interstate transport and sale of natural gas, in addition to the siting of natural gas pipelines under the Natural Gas Act (“NGA”).⁸⁷ However, in its 1979 *Cortez Pipeline Co.* decision, FERC specifically excepted CO₂ from its jurisdiction.⁸⁸ The Surface Transportation Board (“STB”) regulates interstate “pipeline carriers” not transporting “water, gas, or oil.”⁸⁹ The predecessor agency to the STB, the Interstate Commerce Commission (“ICC”), determined in its separate *Cortez Pipeline* decision that, even though CO₂ is transported via pipeline in a “‘super-critical’ state between a gas and a liquid,” its normal state is gaseous and therefore not within the jurisdiction of the ICC.⁹⁰ While the STB itself has never been presented with the question of its jurisdiction over CO₂ pipelines, it is likely that it would follow the decision of the ICC as the statutory language the decision was based on has not changed.⁹¹ Even if the STB does have jurisdiction over CO₂, it does not regulate pipeline siting.⁹²

The BLM may grant CO₂ pipelines rights-of-way across federal land under the MLA.⁹³ In the 1992 case *Exxon Corp. v. Lujan*, Exxon argued that CO₂ pipelines should not be sited under the MLA,⁹⁴ which imposes common carrier requirements.⁹⁵ Instead, Exxon argued that CO₂ pipelines are sited under FLPMA, which entails no carrier requirements.⁹⁶ The Tenth Circuit rejected Exxon’s argument, holding that CO₂ pipelines are subject to the MLA, thereby requiring that CO₂ pipelines serve as common carriers.⁹⁷ It is unclear whether the holding in *Exxon* would apply to pipelines carrying only anthropogenic CO₂ for purposes of geologic storage. Trucked CO₂ would fall under “normal” interstate commerce regulations, including those of the USDOT and the National Highway Traffic Safety Administration (“NHTSA”).⁹⁸

“It is unclear whether the holding in Exxon would apply to pipelines carrying only anthropogenic CO₂ for purposes of geologic storage.”

⁸⁴ Hazardous Liquid Pipeline Safety Act of 1979, 49 U.S.C. §§ 60101–60141 (2018).

⁸⁵ *Id.*

⁸⁶ 49 C.F.R. § 195.1 (2020).

⁸⁷ Natural Gas Act, 15 U.S.C. §§ 717–717z; *see esp.* 717(b) (2018).

⁸⁸ *Cortez Pipeline Company*, 7 F.E.R.C. P 61,024 (1979).

⁸⁹ 49 U.S.C. § 15301 (2018).

⁹⁰ Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 ENERGY L. J. 85, 90–91 (2009) (citing *Cortez Pipeline Co.*, 45 Fed. Reg. 85,177 (1980)).

⁹¹ *Id.* at 92.

⁹² *See* 49 U.S.C. §§ 15501–15506 (2018).

⁹³ *Exxon Corp. v. Lujan*, 970 F.2d 757, 761 (10th Cir. 1992).

⁹⁴ *Id.* at 759.

⁹⁵ 30 U.S.C. § 185(r)(1) (2018).

⁹⁶ *Exxon Corp.*, 970 F.2d at 759.

⁹⁷ *Id.* at 763.

⁹⁸ *See* 49 C.F.R. § 173.301 (2020).

FEDERAL ENVIRONMENTAL LAWS

Key federal environmental laws impact the management and extraction of natural resources from both federal and private lands. A full analysis of all federal environmental laws relative to CO₂-EOR is beyond the scope of this report. The following provides a brief introduction to a sampling of federal environmental laws and their applicability to CO₂-EOR and geologic storage. Numerous other federal laws, including the ESA and the National Historic Preservation Act, may have significant impacts on CO₂ utilization and transport projects and require consultation with other federal agencies and affected stakeholders.

The National Environmental Policy Act

NEPA requires federal agencies to evaluate the environmental impacts of their actions before authorizing “major federal actions significantly affecting the quality of the human environment.”¹

NEPA applies to any major project that involves federal funding, work performed by the federal government, or permits issued by a federal agency. NEPA also applies to federal decisions regarding tribal trust land² and CO₂ projects on private lands when federal permits are necessary.³ In areas where CO₂-EOR has not previously been conducted, the BLM may need to amend its resource management plans and evaluate the environmental impacts of enhanced oil recovery operations, including any necessary pipelines and infrastructure.⁴ However, the cost and timing of NEPA expenditures varies between projects, as a recent study found that the average EIS completion time is 4.5 years.⁵

NEPA also applies to geologic storage projects. The Environmental Protection Agency (“EPA”) implements this requirement in three parts. First, the EPA applies a categorical exclusion (“CatEx”) from EIS requirements to certain activities that do not significantly

impact the environment.⁶ Second, for projects that do not fall into a CatEx, the EPA requires an environmental assessment (“EA”), or succinct report that allows the EPA to determine the extent of a project’s impact.⁷ Third, for those activities that the EPA concludes will have significant effects on the environment, the EPA requires an environmental impact statement (“EIS”).⁸ The current EPA CatExs extend only to small geologic storage demonstration projects,⁹ and larger operations will most likely need to prepare and file an EA and potentially an EIS.¹⁰ Larger geologic storage projects, such as the DOE sponsored Archer Daniels Midland (“ADM”) geologic sequestration project, were evaluated under the EA process. To date, these projects successfully passed EA review, with the DOE ruling that the projects are generally beneficial, when sited properly.¹¹

The Clean Air Act and the GHG Reporting Program

Under the Clean Air Act (“CAA”),¹² the EPA regulates air pollution from emissions that “endanger public health or welfare[.]”¹³ The CAA classifies CO₂ as a greenhouse gas (“GHG”).¹⁴ The Clean Air Act GHG reporting program applies to both CO₂-EOR and geologic storage operations. Under its Greenhouse Gas Reporting Program (“GHGRP”), the EPA requires all CO₂ geologic sequestration wells, specifically Class VI Underground Injection Control (“UIC”) wells, to report all CO₂ received, injected, produced, escaped or emitted, and sequestered, regardless of the quantity.¹⁵ The GHGRP also requires all other CO₂ injection wells to report all CO₂ received.¹⁶ Under subparts RR and UU of the GHGRP, the EPA delineates between CO₂ injected for geologic sequestration (subpart RR) and for all other uses, including enhanced oil and gas recovery (subpart UU). Differences in the costs and requirements of these programs introduce uncertainty in projects and may be an impediment to development, and particularly to transitioning projects from CO₂-EOR to geologic storage.

¹ National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq.* (2018).

² *See* Jicarilla Apache Tribe v. Andrus, 687 F.2d 1324 (10th Cir. 1982).

³ *See* Notice of Availability of the Wyoming Pipeline Corridor Initiative Draft Environmental Impact Statement and Resource Management Plan Amendment for 9 BLM-Wyoming Resource Management Plans, 85 Fed. Reg. 21453-01 (Apr. 17, 2020).

⁴ *Id.*

⁵ COUNCIL ON ENVTL. QUALITY, EXEC. OFFICE OF THE PRESIDENT, FACT SHEET: CEQ REPORT ON ENVIRONMENTAL IMPACT STATEMENT TIMELINES (Jun. 2020).

⁶ 40 C.F.R. § 1508.4 (2020).

⁷ 40 C.F.R. § 1508.9 (2020).

⁸ 40 C.F.R. § 1508.11 (2020).

⁹ 40 C.F.R. § 6.204 (2020).

¹⁰ 40 C.F.R. §§ 1508.9, 1508.11 (2020).

¹¹ Archer Daniels Midland Company for U.S. Dept. of Energy, “CO₂ Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone,” Final Enviro. Assessment: Finding of No Significant Impact (DOE/EA-1828) (April 2011).

¹² Clean Air Act, 42 U.S.C.A. §§ 7401 *et seq.* (2018).

¹³ 42 U.S.C. § 7408(a)(1)(A) (2018).

¹⁴ *See*, 40 C.F.R. §§ 98.440–98.449, 38.470–98.478 (2020).

¹⁵ 40 C.F.R. §§ 98.440–98.449 (2020).

¹⁶ 40 C.F.R. §§ 98.470–98.478 (2020).

The Clean Water Act and Section 404

The CWA¹⁷ applies to CO₂ projects predominantly as a result of its permitting requirements for “construction and earthmoving of sediment from a point source into navigable waters.”¹⁸ The Army Corps of Engineers (“Corps”) governs the discharge of “dredged or fill materials” into waters of the United States under the CWA.¹⁹ The Corps also regulates obstructions or structures built across or through waters of the United States, and the CWA prohibits the building of any such obstruction without a permit from the Corps.²⁰ The Corps generally grants permits for proposed pipelines in such areas under its Nationwide Permit 12 (“NWP 12”).²¹

Recently, the validity of NWP 12 with respect to pipelines has come under scrutiny from environmental groups.²² In May 2020, a federal district court in Montana vacated a pipeline permit issued under NWP 12, holding that the Corps had violated its obligations under the ESA.²³ The ESA requires a federal agency to consult with the Secretary of the Interior to ensure that a proposed project will not threaten an endangered species or its habitat before permitting the project.²⁴ The Montana district court held that the Corps failed to conduct such a consultation, causing both the Corps and the pipeline project to violate the ESA.²⁵

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (“RCRA”)²⁶ governs disposal of hazardous waste and establishes the Hazardous Waste Program. The EPA considers CO₂ streams injected into the subsurface for geologic storage pursuant to Class VI as solid waste. The EPA found that CO₂ constituted a “discarded material” within the plain meaning of the term in RCRA § 1004(27). However, finding that injected CO₂ did not demonstrate many of the characteristics of “hazardous wastes,” the EPA promulgated a 2014 rule granting geologic sequestration activities a conditional exclusion from the requirements of RCRA.²⁷ The conditional exclusion is available to projects

where transportation and injection are in compliance with the U.S. Department of Transportation and Class VI well requirements, and where no other hazardous wastes are mixed or co-injected. To obtain such an exclusion, generators and injectors must certify that they have met all conditions of the exclusion.

The EPA determined that chemical content in a specific CO₂ stream will depend on its source and on the technology used for capture.²⁸ For example, CO₂ from an ethanol production facility will be nearly pure, and trace compounds are likely harmless (H₂O, principally).²⁹ CO₂ captured from a coal-fired powerplant is likely to include trace elements that are present in the flue gas stream, such as mercury or arsenic.³⁰ Because CO₂ streams can vary in trace elements, the EPA could not make a categorical determination of whether any particular injected CO₂ stream was “hazardous” under the RCRA. Instead, the EPA found that it depends on whether a stream contains specific chemical constituents at or above levels defined in regulation.³¹ The net result of this approach is that the agency proposed to effectively limit qualification for Class VI to those CO₂ streams that do not include impurities that would bring the substance within the scope of the RCRA. To accomplish this, the proposed rule simply defines the term “carbon dioxide stream” to exclude “hazardous waste.”³²

The Safe Drinking Water Act and Underground Injection Control Program

Perhaps the most directly applicable federal law to CO₂ projects is the Safe Drinking Water Act (“SDWA”).³³ The SDWA is the principal federal law intended to ensure safe drinking water from public water sources, focusing on public health and source water protection. The SDWA requires the EPA to develop minimum federal requirements for UIC programs, which is designed to provide protection to underground drinking water sources from injection activities and waste disposal. CO₂-EOR operations are conducted under the Class II injection well program, whereas geologic storage operations are conducted under Class VI.

²⁸ See U.S. ENVTL. PROTECTION AGENCY, OFFICE OF WATER, EPA-816-P-13-004, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE DRAFT UNDERGROUND INJECTION CONTROL PROGRAM GUIDANCE ON TRANSITIONING CLASS II WELLS TO CLASS VI WELLS, 43 (2013) [hereinafter UIC Program Guidance on Transitioning Class II Wells to Class VI Wells].
²⁹ See *Biofuels Explained*, U.S. ENERGY INFO. ADMIN., <https://www.eia.gov/energyexplained/biofuels/ethanol-and-the-environment.php> (last visited Aug. 28, 2020).

³⁰ See COUNCIL ON ENVTL. QUALITY, EXEC. OFFICE OF THE PRESIDENT, REPORT OF THE INTERAGENCY TASK FORCE ON CARBON CAPTURE AND STORAGE C-5-7 (2010).

³¹ 40 C.F.R. § 261.24(b) (2020).

³² UIC Program Guidance on Transitioning Class II Wells to Class VI Wells, *supra* note 28, at vii.

³³ The Safe Drinking Water Act, 42 U.S.C. §§ 300f *et seq.* (2018).

¹⁷ Clean Water Act, 33 U.S.C.A. §§ 1251 *et seq.* (2018).

¹⁸ 33 U.S.C. § 1251 (2018).

¹⁹ 33 U.S.C. § 1344 (2018).

²⁰ 33 U.S.C. § 403 (2018).

²¹ See *Sierra Club Inc. v. Bostick*, 787 F.3d 1043 (10th Cir. 2015).

²² *Id.*

²³ *N. Plains Res. Council v. U.S. Army Corps of Eng'rs*, No. CV 19-44-GF-BMM, 2020 WL 3638125, at *14 (D. Mont. May 11, 2020).

²⁴ 16 U.S.C. § 1536 (2018).

²⁵ *N. Plains Res. Council*, 2020 WL 3638125.

²⁶ Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901 *et seq.* (2018).

²⁷ See *generally*, 40 C.F.R. § 261.4(c); Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO₂) Streams in Geologic Sequestration Activities, 79 Fed. Reg. 350 (codified at 40 C.F.R. § 251.4(h)).

Table I. UIC Well Classes

Class	Estimated Number of Permitted Wells	Percentage of Total Wells	Type of Fluid Injected
Class I	781	0.11%	Injection of hazardous and non-hazardous wastes into deep, isolated rock formations
Class II	177,763	24.22%	Injection of fluids associated with oil and natural gas production (including injection of CO ₂ for enhanced recovery and produced water disposal)
Class III	26,714	3.64%	Injection of fluids for solution mining (e.g., extracting uranium or salt)
Class IV	103	0.01%	Injection of hazardous or radioactive wastes through shallow wells into or above formations that contain a USDW (these wells are banned unless authorized under a federal or state groundwater remediation project)
Class V	528,300	72.00%	Any well used to inject non-hazardous fluids underground that does not fall under the other five classes, including storm water drainage wells, septic system leach fields, aquifer storage and recovery wells, and experimental wells; most Class V wells are used for injection of wastes into or above USDWs
Class VI	2	Less than .01%	Injection of CO ₂ into geologic formations for long-term storage or geologic sequestration (both wells at one site)
TOTAL	733,663		

Sources: 40 C.F.R. §144.6; EPA, *FY18 State UIC Injection Well Inventory*.

Note: This table does not include tribal wells, which include Class I, Class II, and Class V wells (totaling 6,528 wells, according to EPA's *FY18 Tribal UIC Injection Well Inventory*).

Table 1. Number of UIC injection well by class. Taken from CRS Report 46192 (Jones, 2020).

Class II wells—which include EOR and EGR projects—do not differentiate based on the source of the fluid to be injected (i.e. whether the CO₂ is artificial or naturally occurring), but limit injections to those used for enhanced recovery of oil or gas. Therefore, an injection well operating under a Class II permit may not be used to continue to inject CO₂ once EOR/EGR operations have come to an end.³⁴ This regulatory distinction is important.³⁵ All states in which significant EOR operations are underway have qualified for primacy status for Class II CO₂ injection wells. In most cases, the state oil and gas commission (or similar agency) serves as the responsible agency in each state for implementing the UIC Program for these wells. In contrast, the EPA Regions have issued only two permits for CO₂-EOR wells. In practice, practical oversight responsibility and expertise in dealing with underground injection of CO₂ primarily exists at the state level.³⁶

³⁴ UIC Program Guidance on Transitioning Class II Wells to Class VI Wells, *supra* note 28, at ii (stating, “[I]f the Class VI UIC Program Director has determined there is no increased risk to USDWs, then these operations would continue to be permitted under the Class II requirements”).

³⁵ See Philip M. Marston & Patricia A. Moore, *From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 ENERGY L. J. 421 (2008).

³⁶ *Id.* at 467.

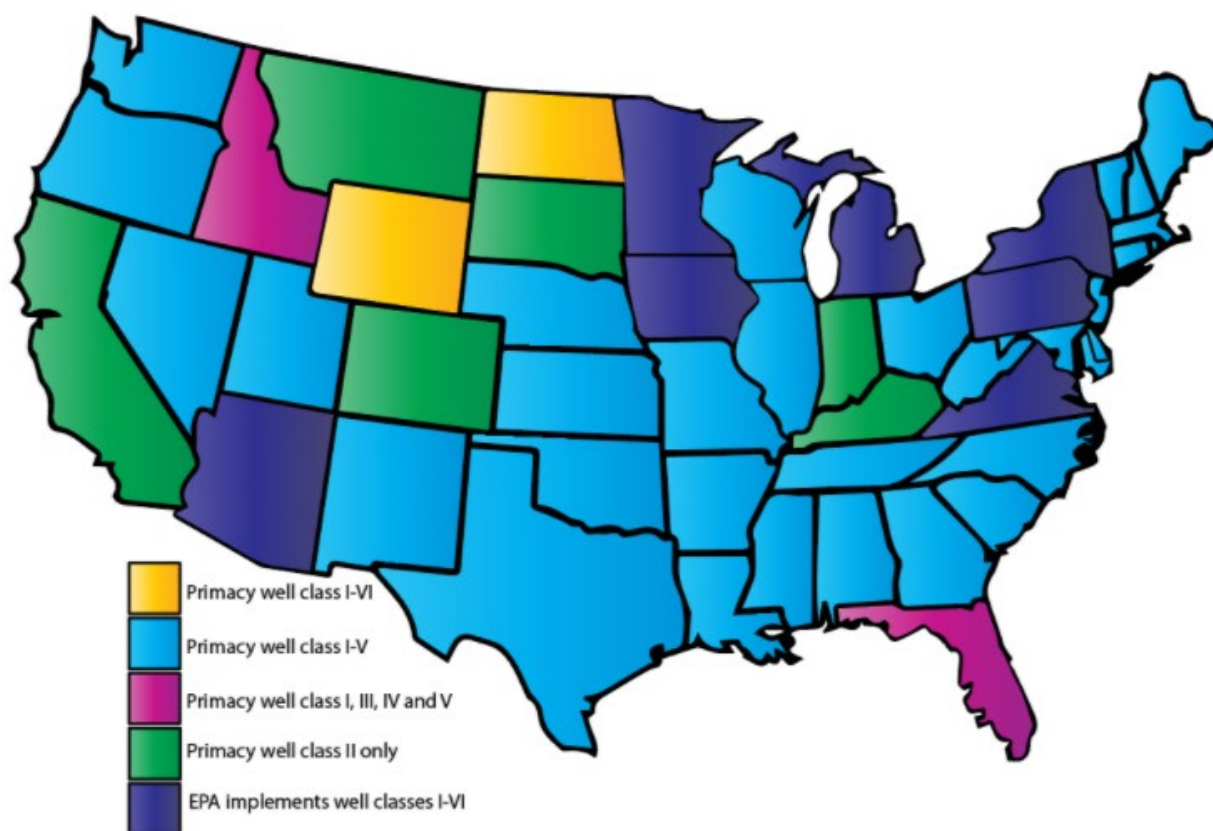


Figure 1. UIC Primacy Map. Updated from CRS Report 46192 (Jones, 2020)

The technical, monitoring, and post-closure requirements for Class VI are the most stringent of all UIC classes, including those for hazardous wastes.³⁷ Notably, the “Area of Review” for Class VI wells is larger and includes the subsurface 3-D extent of the CO₂ plume. The requirements obligate well owners or operators to track, model, and predict the CO₂ plume movement, and monitoring and post-closure requirements are expected to operate between 30 and 60 years. Further, Class VI requirements impose more comprehensive performance requirements and shorter time periods between mandatory testing and reporting, and require seismicity monitoring, monitoring of injection pressures, and pressure front and monitoring for groundwater quality through the lifetime of the project – all more stringent requirements than those required for other wells, including Class II. Finally, Class VI requirements impose post-injection site care and emergency or remedial requirements, which are not included for other wells.

In the Class VI rule, the EPA addressed stakeholder liability and long-term stewardship only to state that the agency does not have authority to determine property rights or to transfer liability from one owner to another, and that the existing federal framework does not provide for a release or transfer of liability from the owner/operator to other persons.³⁸ Issues of financial liability and long-term stewardship of these sites and reservoirs is largely unresolved.³⁹

³⁷ See, e.g., UIC Program Guidance on Transitioning Class II Wells to Class VI Wells, *supra* note 28, Table 1.

³⁸ ANGELA C. JONES, CONG. RESEARCH SERV., R46192, INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: FEDERAL ROLE AND ISSUES FOR CONGRESS 18 (2020).

³⁹ *Id.*

The EPA released draft guidance and interpretation on the transition of Class II wells to Class VI wells.⁴⁰ The guidance suggests a “risk-based” approach to permitting based on consideration of numerous factors including injection rates, reservoir pressures, and the geologic characterization of the reservoir.⁴¹ Pursuant to this guidance, the EPA subsequently released a two-page memorandum specifying the key principles related to the transition of Class II wells to Class VI wells. The memorandum specified that use of anthropogenic CO₂ in EOR operations did not necessitate a Class VI permit, and that geologic storage operations associated with oil and gas activities could continue without a Class VI Permit. The memorandum further clarified that CO₂-EOR injection operations are managed under Class II and not subject to Class VI closure requirements. This guidance seems somewhat conflicting, relative to transition to incremental storage, and given the more stringent requirements for Class VI would likely provide a strong disincentive to an operator to complete a transition from Class II/oil and gas production primarily to Class VI/CO₂ sequestration primarily.

“Class VI requirements impose post-injection site care and emergency or remedial requirements, which are not included for other wells. ”



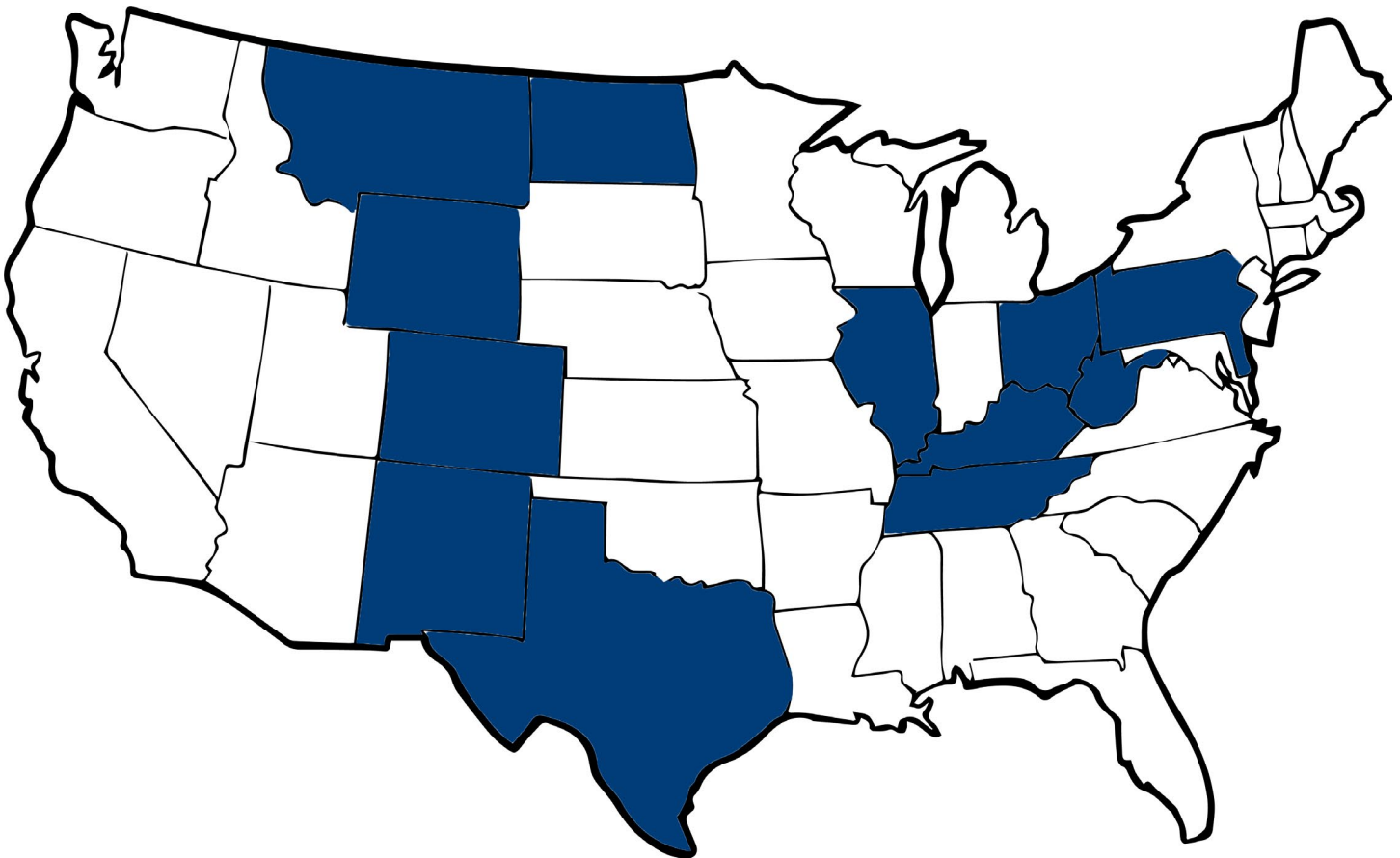
⁴⁰ UIC Program Guidance on Transitioning Class II Wells to Class VI Wells, *supra* note 28.

⁴¹ This section specifies nine criteria that the UIC program director must consider in the determination of risk to USDWs. 40 C.F.R. § 144.19(b)(1)–(9) (2020).

STATE ASSESSMENTS

The following chapters provide a summary of laws, policies, and regulations that pertain to CO₂-EOR in geologic storage in a survey of states throughout the Rocky Mountain interior west and Appalachia. These areas were chosen in order to provide areas of regional analysis and also to permit contrast between predominant legal frameworks as they exist in key areas of oil and gas production. Study of these two regions also drew upon the regional expertise of the contributors, with faculty at the University of Wyoming focusing on western states and faculty at the University of West Virginia focusing on eastern states. Additional analysis is necessary to fully understand the legal landscape for CO₂-EOR and geologic storage and to appreciate challenges to implementation.

Each report includes an overview of state laws and regulations related to mineral ownership, subsurface property, water rights, eminent domain, pipeline siting, oil and gas operations, and geologic storage.



COLORADO

Executive Summary

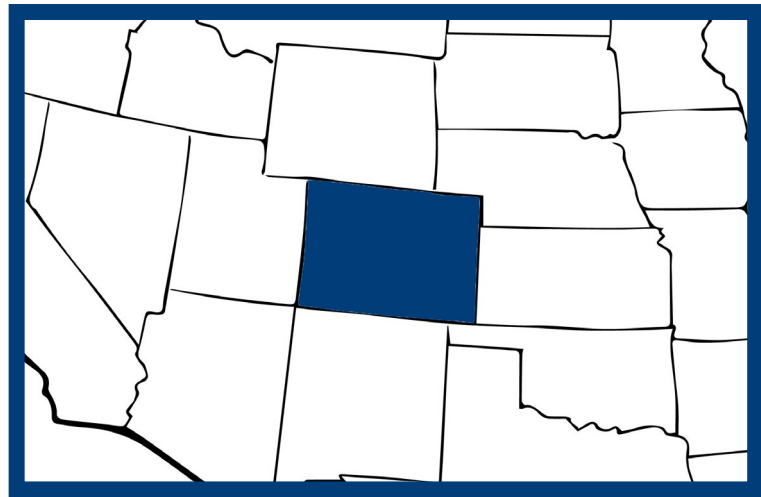
Colorado's newly revised Oil and Gas Conservation Act uniquely requires the Colorado Oil and Gas Conservation Commission to regulate oil and gas development to ensure that it not only prevents waste and protects correlative rights, but also that it protects the environment and wildlife. In addition, local governments are granted jurisdiction to regulate some aspects of oil and gas operations. Despite large CO₂ reserves and capacity for significant geologic and incremental storage, uncertainties regarding state and local regulation, CO₂ classification with the mineral estate, pore space ownership, eminent domain authority for CO₂ and oil pipelines, and ownership and liability for injected CO₂ will complicate storage projects and proposals.

Background:

Colorado includes federal, state, fee, and tribal land. Colorado includes two portions of tribal land that comprise a combined 882,838 acres in the southwestern corner of the state. Of the 66,485,760 acres of land in the state, 24,100,247 acres (36.2%) is federally owned. The vast majority of these federally owned lands lie to the west of the front range and are managed by the U.S. Forest Service or the National Park Service.

Colorado operates under a common law legal system. Colorado's district courts serve as the state's trial courts of general jurisdiction. The district court system in Colorado is composed of 22 judicial districts. District court decisions are appealed first to the Colorado Court of Appeals and then to the Colorado Supreme Court. Additionally, Colorado has water courts that possess exclusive jurisdiction over cases involving water matters. There are seven water court divisions, one for each major river basin in the state, and five additional judges that are devoted to water matters involving a designated groundwater basin. Appeals from a water judge's determination are filed directly with the Colorado Supreme Court. Colorado is one of only three states that has a separate water court system.

Numerous state and local governmental entities regulate CO₂-EOR in Colorado. These include the Colorado Oil and Gas Conservation Commission ("COGCC"); the Department of Public Health & Environment, through its Water Quality Control Division and its Air Pollution Control Division; county and local governments; and the Division of Parks and Wildlife.



CO₂-EOR in Colorado:

Presently, Colorado has only one CO₂-EOR operation, located in the Rangely Field on the state's western border in the Uinta Basin.¹ However, the state has a long history of supplying CO₂ to other states for use in EOR operations. Colorado, along with New Mexico and Arizona, developed natural CO₂ sources that were vital to the early use of CO₂-EOR in the Permian Basin of West Texas in the 1970s.² Colorado has large natural CO₂ reserves, largely located in the Paradox, Raton, and North Park basins. Production since the mid-1980s has equaled roughly 300 billion cubic feet ("Bcf") annually.³ 451,607,569 thousand cubic feet ("Mcf") of CO₂ was produced statewide in 2019 alone, with 420,033,283 Mcf of that coming from Montezuma county.⁴ Colorado also has numerous potential anthropogenic sources that may be candidates for capture of CO₂, though to date none of these have been developed. At the beginning of 2020, Occidental Petroleum announced its plans to partner with Total on a major carbon capture project targeting 725,000 metric tons ("MT") of carbon per year at the Holcim Portland cement plant in Fremont County, Colorado.⁵

¹ See CHEVRONTEXACO'S RANGELY OIL FIELD OPERATIONS (2005). <http://emfi.mines.edu/emfi2005/ChevronTexaco.pdf>.

² GLOBAL ENERGY INSTITUTE, CO₂ ENHANCED OIL RECOVERY, https://www.globalenergyinstitute.org/sites/default/files/020174_EI21_EnhancedOilRecovery_final.pdf (last visited May 31, 2020).

³ Genevieve B.C. Young et al., *CO₂ Sequestration Potential of Colorado*, COLO. GEOLOGICAL SURVEY RESOURCE SERIES 45, 1-13 – 16 (2007).

⁴ COLO. OIL & GAS CONSERVATION COMM'N, COGCC REPORTS PORTAL: 2019 MONTHLY CO₂ PRODUCED BY COUNTY, <https://cogcc.state.co.us/COGCCReports/production.aspx?id=MonthlyCO2ProdByCounty> (last visited June 2, 2020).

⁵ Jordan Blum, *Oxy, Total partner on carbon capture project in Colorado*, HOUS. CHRON. (Jan. 6, 2020), <https://www.houstonchronicle.com/business/energy/article/Oxy-Total-partner-on-carbon-capture-project-in-14952579.php#:~:text=The%20project%20would%20target%20capturing,or%20even%20in%20West%20Texas> (last visited June 2, 2020).

The Colorado Geological Survey estimates that Colorado has a CO₂ sequestration potential of over 720 billion tons, primarily in the Denver Basin, Canon City Embayment, and Piceance and Sand Wash basins. In 2004, Colorado had nine underground gas storage facilities, located primarily in the Denver and Piceance basins.⁶

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

Colorado courts use a “four corners” approach to discern the intent of the parties when interpreting a deed.⁷ They may also provisionally look at extrinsic evidence to determine whether a document is ambiguous.⁸

Colorado courts have held that the term “mineral” in a deed or conveyance may be ambiguous. As applied to surface minerals, Colorado courts have held that the term is inherently ambiguous.⁹ In contrast, substances with a “settled meaning” as part of the mineral estate, such as oil, gas, gold, silver, copper, and lead, are automatically included in a general grant or reservation of “minerals” unless there is language in the instrument indicating otherwise.¹⁰ If the term is ambiguous, the court will consider extrinsic evidence to determine the intent of the parties.¹¹

Colorado courts apply a two-factor test to determine whether or not an unnamed subject is classified as mineral in a general grant: first, whether a particular substance is “exceptional in use, in value, and in character, and does not mean ordinary soil” and, second, whether that substance is considered a mineral in “the vernacular or the mining world, the commercial world and landowners at the time of the grant, and whether the particular substance was so regarded as a mineral.”¹² For example, in *Farrel v. Sayre*, the Colorado Supreme Court applied this two-step analysis to determine that sand and gravel were not part of the reserved mineral estate under review.¹³ Colorado courts have not concluded that CO₂ has a settled meaning as part of the mineral estate, or

as particularly distinguished from “gas,” and therefore ownership must be determined by an analysis of extrinsic evidence to determine the intent of the parties.¹⁴

Ownership of a mineral estate is an interest in real property.¹⁵ The mineral estate itself may be severed into multiple estates. For example, oil and gas interests are, in and of themselves, interests in real property and may be conveyed separately from the rest of the mineral estate.¹⁶ Similarly, royalty interests in minerals are freely alienable and considered a real property interest.¹⁷ If confronted with multiple conflicting mineral estates, Colorado courts will analyze the various deeds to determine the intent of the parties.

Split Estates

A severed mineral estate retains the right to use the surface estate for the development of the mineral estate under the “rule of reasonable use.” This doctrine limits the mineral owner’s (or mineral lessee’s) use of the surface estate to what “is reasonable and necessary to the development of the mineral interest.”¹⁸ This rule does not create an ownership interest in the surface estate, “but merely a right of access.”¹⁹ While the mineral estate is the dominant tenement under the common law, the Colorado Supreme Court, sitting *en banc*, held in 1997 that the mineral and surface estates are “mutually dominant and mutually servient because each is burdened with the rights of the other.”²⁰

Oil and gas operators are statutorily required to accommodate the surface owner by “minimizing intrusion upon and damage to the surface of the land.”²¹ Although this requirement does not prohibit an operator from entering on the land for oil and gas operations,²² an operator is required to consult with the surface owner before commencing operations,²³ and may be required to select different locations for wells, roads, and other facilities, or use alternative operating methods to “prevent, reduce, or mitigate the impacts of the oil and gas operations on the surface”²⁴ The COGCC also imposes a public

¹⁴ See *Keith*, 140 P.3d at 46 (quoting a reservation that explicitly named carbon dioxide as a part of the mineral estate “[a]ll oil, gas, carbon dioxide, and any other minerals in, on, or under . . .”).

¹⁵ COLO. REV. STAT. ANN. § 10-11-123(1)(a) (West 2020); COLO. REV. STAT. § 24-65.5-102(5) (West 2020).

¹⁶ *OXY USA Inc. v. Mesa Cty. Bd. of Comm’rs*, 405 P.3d 1142, 1144 (Colo. 2017).

¹⁷ COLO. REV. STAT. ANN. § 38-30-107.5(1) (West 2020).

¹⁸ *Gerrity Oil & Gas Corp. v. Magness*, 946 P.2d 913, 926-27 (Colo. 1997), *as modified on denial of reh’g* (Oct. 20, 1997).

¹⁹ *Id.*

²⁰ *Id.*

²¹ COLO. REV. STAT. ANN. § 34-60-127(1)(a) (West 2020).

²² § 34-60-127(1)(c).

²³ 2 COLO. CODE REGS. § 404-1:306 (West 2020).

²⁴ § 34-60-127(1)(b).

⁶ Genevieve B.C. Young et al., *supra* note 3 at 1-13-16.

⁷ *Appling v. Fed. Land Bank of Wichita*, 816 P.2d 297, 299 (Colo. App. 1991).

⁸ *Lazy Dog Ranch v. Telluray Ranch Corp.*, 965 P.2d 1229, 1235 (Colo. 1998), *as modified on denial of reh’g* (Oct 19, 1998); *see also O’Brien v. Village Land Co.*, 794 P.2d 246, 249 (Colo. 1990).

⁹ *Keith v. Kinney*, 140 P.3d 141, 148 (Colo. App. 2005).

¹⁰ *Id.*, at 150; *McCormick v. Union Pacific Resources Co.*, 14 P.3d 346, 352 (Colo. 2000)

¹¹ *Farrell v. Sayre*, 260 P.2d 190, 192 (Colo. 1954); *McCormick*, 14 P.3d at 349, 51; *Keith*, 140 P.3d at 147.

¹² *McCormick*, 14 P.3d at 351, *citing Farrell*, 270 P.2d at 192.

¹³ *Farrell*, 270 P.3d at 192.

comment period of at least 20 days prior to approving operations.²⁵ If an operator fails to adequately minimize intrusion on the surface estate, the surface owner may bring a claim against the operator in district court and may seek compensatory damages.²⁶

Pore Space Ownership

Colorado has not settled ownership of pore space between owners of mineral and surface estates. In 2010, an interagency task force on carbon sequestration stated that carbon storage project managers would have to reach an agreement with the pore space owner prior to beginning injection, and indicated that, where the mineral estate had already been severed, it could be difficult to identify the pore space owner.²⁷ Unless parties can agree as to ownership of pore space, Colorado courts would undertake analysis of the specific deed to determine whether the initial grant or reservation was intended to convey or reserve the pore space. Were the pore space determined to be part of the surface estate, the severed mineral interest owner's right to reasonably use the surface to develop the mineral estate would likely extend to pore space for CO₂-EOR and disposal of produced water from the premises.

Water Rights

Water in Colorado, including tributary groundwater,²⁸ is subject to appropriation.²⁹ Priority of water rights between classes of users is established in the state Constitution. The Colorado Constitution provides that priority of appropriation applies between users within the same class, but "when insufficient water exists to satisfy all existing appropriations, domestic uses will have priority."³⁰ In similar deficiencies, agricultural purposes have preference over water for manufacturing purposes.³¹

Use and allocation of non-tributary groundwater is administered according to the Colorado Groundwater Management Act.³² This act authorizes the Colorado Ground Water Commission ("CGWC") to promote the beneficial use of "designated groundwaters" in reasonable amounts and to allow for the allocation of "nontributary

groundwater" in a way that contemplates beneficial use in amounts based upon conservation of the resource and protection of vested rights.³³ The CGWC evaluates applications from prospective users of designated groundwater to determine whether unappropriated waters exist in the designated source and whether the appropriation would unreasonably impair existing water rights or create unreasonable waste.³⁴ To construct a new well, or modify an existing well outside the boundaries of a designated groundwater basin, a prospective user must file a permit application with the state engineer.³⁵ All oil and gas wells constructed after August 1, 2010 are required to obtain a permit prior to producing tributary groundwater.³⁶ These permits are transferrable, subject to administrative filing requirements.³⁷ Non-tributary groundwater produced during oil and gas operations is subject to COGCC regulation if the produced water is disposed or re-injected for enhanced recovery projects.³⁸

³³ See COLO. REV. STAT. ANN. § 37-90-102 (West 2020); see also COLO. REV. STAT. ANN. § 37-90-103(6)(a) (defining "designated groundwater" as "groundwater which in its natural course would not be available to and required for the fulfillment of decreed surface rights, or groundwater in areas not adjacent to a continuously flowing natural stream wherein groundwater withdrawals have constituted the principal water usage for at least fifteen years preceding the date of the first hearing on the proposed designation of the basin, and which in both cases is within the geographic boundaries of a designated groundwater basin"); see also § 37-90-103(10.5) (defining "nontributary groundwater" as "groundwater located outside the boundaries of any designated groundwater basins in existence on January 1, 1985, the withdrawal of which will not, within one hundred years of continuous withdrawal, deplete the flow of a natural stream... at an annual rate greater than one-tenth of one percent if the annual rate of withdrawal").

³⁴ COLO. REV. STAT. ANN. § 37-90-107(4) (West 2020); see also COLO. REV. STAT. ANN. § 37-90-107(5) (providing factors for determining whether a proposed use will create unreasonable waste or unreasonably affect existing rights, including "the area and geologic conditions, the average annual yield and recharge rate of the appropriate water supply, the priority and quantity of existing claims of all persons to use the water, the proposed method of use, and all other matters appropriate to such questions.").

³⁵ COLO. REV. STAT. ANN. § 37-90-137(1) (West 2020).

³⁶ *Id.*

³⁷ See COLO. REV. STAT. ANN. § 37-90-143 (West 2020); see also COLO. DEP'T OF NAT. RES., DIV. OF WATER RES., GROUNDWATER, WELL PERMITTING – CHANGE IN OWNER NAME/ADDRESS, <http://water.state.co.us/groundwater/wellpermit/Pages/default.aspx> (last visited June 16, 2020) (stating that "any unexpired permit that is sold, or conveyed by other means, the new owner(s) of the well permit must file with the State Engineer an update of the new owner name and mailing address . . .").

³⁸ See Series E&P Waste Management, 2 CODE OF COLO. REGS. 404-1:901 to 1:911 (West 2020); Series Unit Operations, Enhanced Recovery Projects, and Storage of Liquid Hydrocarbons, 2 CODE OF COLO. REGS. 404-1:401 to 1:405 (West 2020).

²⁵ 2 COLO. CODE REGS. § 404-1:305-306 (West 2020).

²⁶ § 34-60-127(2).

²⁷ COLORADO CCS TASK FORCE, REPORT OF THE INTERAGENCY TASK FORCE ON CARBON CAPTURE AND STORAGE, 49 (Aug., 2010), <https://www.osti.gov/servlets/purl/985209> (last visited June 30, 2020).

²⁸ *Chatfield E. Well Co., Ltd. v. Chatfield E. Prop. Owners Ass'n*, 956 P.2d 1260 (Colo. 1998).

²⁹ COLO. CONST. art XVI, § 5.

³⁰ COLO. CONST. art XVI, § 6.

³¹ *Id.*

³² COLO. REV. STAT. ANN. § 37-90-101 (West 2020) (explaining that §§ 37-90-101 through 37-90-143 "shall be known and may be cited as the 'Colorado Groundwater Management Act'").

Water rights may be condemned by a municipality by filing a petition within a district court of competent jurisdiction.³⁹ The court will appoint three disinterested commissioners to determine the necessity of exercising eminent domain as proposed and to appraise and award damages that may be sustained by reason of the appropriation and condemnation.⁴⁰ A municipal condemnation will not be allowed for speculative needs more than fifteen years in the future or to condemn waters that have already been appropriated for a public use.⁴¹

Lithium Ownership and Extraction

Our research did not reveal any laws or regulations in Colorado with respect to lithium extraction. There are currently no mines in Colorado that produce lithium, although mines in Gunnison County were an important source of lithium during WWII.⁴² Lithium-bearing minerals have been documented in Fremont and Larimer counties. There is current lithium exploration in southwest Colorado, in conjunction with a lithium project in the Paradox Basin.⁴³

Classification of CO₂: Commodity and Pollutant

Colorado classifies CO₂ as both a commodity and a pollutant. For purposes of taxation, CO₂ is classified as a gas and is subject to a severance tax.⁴⁴ CO₂ is classified as a greenhouse gas and an air pollutant for purposes of the Colorado Department of Public Health & Environment's Air Quality Control Program.⁴⁵ Greenhouse gasses, including CO₂, from major stationary sources are regulated pursuant to Colorado's air quality program.⁴⁶

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The Colorado Oil and Gas Conservation Act ("OGCA") tasks the COGCC with regulating "the development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including

protection of the environment and wildlife resources,"⁴⁷ and which prevents waste and protects correlative rights.⁴⁸ Comprehensive revisions to Colorado's Oil and Gas Conservation Statute in 2019 created the most extensive mandate for protection of the environment and wildlife of any oil and gas commission in the country. Colorado uniquely defines waste as excluding the non-production of oil and gas where necessary to protect the environment.⁴⁹

The COGCC exercises broad authority over oil and gas development, including seismic operations, drilling, producing and plugging of oil and gas wells, well stimulation, and the spacing and number of wells (except with respect to mineral deposits located on tribal land).⁵⁰ This directive encompasses regulation of CO₂-EOR.⁵¹

Colorado's OGCA differs from other states in its extensive consultation requirements regarding sensitive drilling locations⁵² and its shared governance with local government agencies. Before applying for a COGCC permit, an operator must apply for permission from the local government with jurisdiction (defined as either a city or county where the operation is proposed to be sited),⁵³ or demonstrate that the local government does not regulate the siting of oil and gas operations.⁵⁴ Additionally, at least 30 days before drilling operations begin, the operator must provide written notice to the surface owner and the local government detailing the date of commencement and locations for wells, roads, and other production

"Colorado's OGCA differs from other states in its extensive consultation requirements regarding sensitive drilling locations and its shared governance with local government agencies."

³⁹ COLO. REV. STAT. ANN. § 38-6-202(1) (West 2020).

⁴⁰ *Id.*

⁴¹ § 38-6-202(2).

⁴² Stephen D. Schwochow & A.L. Hornbaker, *Geology and Resource Potential of Strategic Minerals in Colorado*, COLORADO GEOLOGICAL SURVEY, INFORMATION SERIES 17, 8 (1985).

⁴³ NEW TECH MINERALS CORP, PARADOX BASIN POTASH, <https://newtechminerals.ca/projects/paradpc-basin/> (last visited June 30, 2020).

⁴⁴ See COLO. REV. STAT. ANN. § 32-29-102(2.5) (West 2020) (defining "gas" as "natural gas, coalbed methane, and carbon dioxide"); see also COLO. REV. STAT. ANN. § 39-29-105 (West 2020) (subjecting carbon dioxide to severance taxes).

⁴⁵ 5 CODE OF COLO. REGS. § 1001-2:1.G (West 2020).

⁴⁶ 5 CODE OF COLO. REGS. § 1001-5:3A.I.B.44.d (West 2020)

⁴⁷ COLO. REV. STAT. ANN. § 34-60-102(1)(a)(I) (West 2020).

⁴⁸ § 34-60-102(1)(a)(II) to (IV).

⁴⁹ COLO. REV. STAT. ANN. § 34-60-103(13)(b) (West 2020).

⁵⁰ COLO. REV. STAT. ANN. § 34-60-103, 105, 106(2) (West 2020).

⁵¹ 2 COLO. CODE REGS. § 404-1:401 (West 2020).

⁵² 2 CODE OF COLO. REGS. § 404-1:306.c.(2).A (West 2020).

⁵³ COLO. REV. STAT. ANN. § 34-60-103(5.3) (West 2020).

⁵⁴ COLO. REV. STAT. ANN. § 34-60-106(1)(f) (West 2020).

facilities.⁵⁵ Operations located in a Sensitive Wildlife Habitat or Restricted Surface Occupancy Area are subject to 16 additional requirements designed to minimize ecological surface impacts.⁵⁶

The COGCC has authority to pool or unitize property interests for enhanced recovery purposes. The COGCC may modify the “rule of capture” through spacing or pooling orders.⁵⁷ In order to pool interests for a single drilling and spacing unit, at least 45% “of the mineral interests to be pooled” must consent.⁵⁸ Unitization for enhanced recovery projects in excess of a single drilling and spacing unit require COGCC approval and consent from at least 80% of both the working interest owners and the royalty interest owners.⁵⁹ Additional rules regarding unit operations and EOR applications can be found in Series 400 of the Rules and Regulations of the COGCC.⁶⁰

The COGCC is also charged with regulating underground natural gas storage.⁶¹ For purposes of the storage statutes, Colorado has defined “natural gas” as “gas which has been produced from the earth in its original state or such gas after the same has been processed or treated.”⁶² Underground reservoirs are “any subsurface sand, stratum, or formation suitable for the injection and storage of natural gas therein”⁶³ Natural gas public utilities have a right of property condemnation for such “natural gas” storage, but must apply to the COGCC before beginning storage operations.⁶⁴ Injectors maintain ownership of injected natural gas.⁶⁵

Although Colorado does not have any laws specifically addressing injection-induced seismicity, the COGCC reviews injection well applications for seismic potential. COGCC policy mandates that injectors keep both pressure and injection levels below maximum standards designated for each well.⁶⁶ Additionally, the

⁵⁵ COLO. REV. STAT. ANN. § 34-60-106(14) (West 2020).

⁵⁶ 2 CODE OF COLO. REGS. § 404-1:1202.a (West 2020) (stating the above proposition and explaining that “minimize adverse impacts shall mean wherever reasonably practicable, to (i) avoid adverse impacts from oil and gas operations of wildlife resources, (ii) minimize the extent and severity of those impacts that cannot be avoided, (iii) mitigate the effects of unavoidable remaining impacts, and (iv) take into consideration cost-effectiveness and technical feasibility with regard to actions taken and decisions made to minimize adverse impacts to wildlife resources, consistent with the other provisions of the Act”).

⁵⁷ *INB Land & Cattle, LLC v. Kerr-McGee Rocky Mountain Corp.*, 190 P.3d 806, 808 (Colo. App. 2008).

⁵⁸ COLO. REV. STAT. ANN. § 34-60-116(3) (West 2020).

⁵⁹ See COLO. REV. STAT. ANN. § 34-60-118(5) (West 2020).

⁶⁰ 2 CODE OF COLO. REGS. § 404-1:401 to 1:405.

⁶¹ COLO. REV. STAT. ANN. § 34-64-101 to 107 (West 2020).

⁶² COLO. REV. STAT. ANN. § 34-64-102(3) (West 2020).

⁶³ § 34-64-102(4).

⁶⁴ COLO. REV. STAT. ANN. § 34-64-104 to 106 (West 2020).

⁶⁵ COLO. REV. STAT. ANN. § 34-64-107 (West 2020).

⁶⁶ ENGINEERING UNIT, COLO. OIL & GAS CONSERVATION COMM’N, SEISMICITY REVIEW FOR CLASS II UNDERGROUND INJECTION CONTROL WELLS,

COGCC monitors basement rocks and sealing zones to reduce potential for induced seismicity.⁶⁷

Although there is no statutory priority between multiple mineral estates, counties are required to adopt mineral extraction plans for “effective multiple sequential use,”⁶⁸ and oil and gas operators are required to conduct operations in a manner that does not damage underlying coal estates⁶⁹ and avoids waste.⁷⁰ An operator must report any “workable” coal seam discovered while drilling.⁷¹ Any borehole drilled through a workable coal seam must be properly cased to prevent contamination of the coal seam by surface water, produced water, or oil and gas.⁷² Additionally, boreholes must be located certain defined distances from any coal mining facilities.⁷³

“Although there is no statutory priority between multiple mineral estates, counties are required to adopt mineral extraction plans for “effective multiple sequential use.”

Pipeline Regulation

The Colorado Public Utilities Commission (“CPUC”) enforces the federal Natural Gas Pipeline Safety Act⁷⁴ and regulates the safety of intrastate natural gas pipelines.⁷⁵ The COGCC regulates materials, design, installation, maintenance, repair, and inspection of pipelines, transfer lines, and gathering lines used in oil and gas production.⁷⁶ Interstate pipelines and all hazardous material pipelines in Colorado are subject to PHMSA rules, regulations, and enforcement.⁷⁷

1 (2011), https://cogcc.state.co.us/documents/about/TF_Summaries/GovTaskForceSummary_Sesimicity_Review_for_Class_II_Underground_Injection_Control_Wells.pdf.

⁶⁷ *Id.* at 2.

⁶⁸ COLO. REV. STAT. ANN. § 34-1-304 (West 2020).

⁶⁹ See *Oil Wells and Boreholes*, COLO. REV. STAT. ANN. § 34-61-101 to 108 (West 2020).

⁷⁰ COLO. REV. STAT. ANN. § 34-60-107 (West 2020).

⁷¹ COLO. REV. STAT. ANN. § 34-61-101 (West 2020).

⁷² COLO. REV. STAT. ANN. § 34-61-103 to 105 (West 2020).

⁷³ COLO. REV. STAT. ANN. § 34-61-102 (West 2020).

⁷⁴ COLO. REV. STAT. ANN. § 40-2-115 (West 2020).

⁷⁵ 4 COLO. CODE REGS. 723-4:4900 (West 2020).

⁷⁶ 2 COLO. CODE REGS. § 404-1:100 (West 2020); 2 COLO. CODE REGS. § 404-1:1102 (West 2020).

⁷⁷ Pipeline Safety Programs and Rulemaking Procedures, 49 C.F.R. 190.1-411; see also Rules Regarding Gas Utilities and Pipeline Op-

State Environmental Laws

The EPA manages the UIC program in Colorado except with respect to Class II wells. Colorado was granted primacy over Class II wells on April 2, 1984 and regulates them through the COGCC.⁷⁸ The COGCC maintains UIC standards according to EPA regulations.⁷⁹

Impacts on air quality from oil and gas operations, including injection operations, are regulated by the Colorado Department of Environmental Quality. Additionally, the Colorado Air Pollution Prevention and Control Act (“CAPPCA”) and regulations promulgated by the Air Quality Control Commission may apply to capture and injection facilities that constitute a new stationary source or new indirect air pollution source.⁸⁰

The discharge of pollutants into state waters is managed by the Colorado Water Quality Control Commission pursuant to The Colorado Water Quality Control Act.⁸¹ Colorado Water Quality Control Commission rules provide that “[n]o person shall discharge any pollutant into any state water from a point source without first having obtained a permit from the Division for such discharge.”⁸²

Industrial Siting Requirements

Our research revealed no statewide EOR-specific siting requirements. Local government regulations may apply to siting of CO₂-EOR facilities.⁸³

CPUC regulates natural gas pipeline siting in Colorado. Operators must file a map of the proposed location of the pipeline with the county clerk, and corporations formed “for the purpose of constructing a pipeline for the conveyance of gas, water, or oil” are required to include the proposed pipeline locations in their articles of incorporation.⁸⁴ CPUC reserves the right to question and change, upon proper notice and hearing, an operator’s planned pipeline locations.⁸⁵ Our research

erators4 CODE OF COLO. REGS. § 723-4:4000 to 4976 (West 2020).

⁷⁸ See Colorado Oil and Gas Conservation Commission; Underground Injection Control; Program Approval, 49 Fed. Reg. 13040 (approved April 2, 1984) (codified at 40 C.F.R. § 147.300).

⁷⁹ COLO. OIL & GAS CONSERVATION COMM’N, COGCC UNDERGROUND INJECTION CONTROL AND SEISMICITY IN COLORADO, DEP’T OF NAT. RES. (2011), <https://media.bizj.us/view/img/3037491/inducedseismicityreview.pdf>.

⁸⁰ See 5 CODE OF COLO. REGS. § 1002-61:61.3 (West 2020); see also COLO. REV. STAT. ANN. § 25-7-114.2 (West 2020).

⁸¹ COLO. REV. STAT. ANN. § 25-8-202 (West 2020) (creating the Colorado Water Quality Control commission); see also COLO. REV. STAT. ANN. § 25-8-101 (West 2020) (explaining that §§ 25-8-101 through 25-8-803 “shall be known and may be cited to as the ‘Colorado Water Quality Control Act’”).

⁸² 5 CODE OF COLO. REGS. § 1002-61:61.3 (West 2020).

⁸³ COLO. REV. STAT. ANN. § 29-20-104(1)(h)(II) (West 2020).

⁸⁴ COLO. REV. STAT. ANN. § 7-43-102 (West 2020).

⁸⁵ 4 COLO. CODE REGS. § 723-4:4954 (West 2020).

revealed no statutes or regulations relating directly to siting for CO₂ pipelines.

Local Regulation

Local regulation of oil and gas activities is a significant factor in the development of CO₂-EOR or storage projects in the state. Colorado’s constitution allows cities with a population over 2,000 to pass a charter allowing them to “supersede within the territorial limits and other jurisdiction of said city or town any law of the state in conflict therewith.”⁸⁶ However, this sweeping language does not give home rule cities plenary power within their jurisdiction. When analyzing city ordinances, Colorado courts will examine whether the issue is one of local, state, or mixed interest. If the matter is of local interest, the local ordinances supersede any state laws.

If the matter is of statewide interest, municipalities have no power to act, unless otherwise authorized by the Colorado Constitution or a state statute. Finally, if the issue is of mixed local/statewide interest, state law will preempt any conflicting local law.⁸⁷ Counties may also adopt a home rule charter, although home rule counties do not have the same power to supersede state laws that home rule cities do. Rather, home rule counties are limited to regulating areas that the state statutorily permits.⁸⁸

Colorado has statutorily limited state preemption of local regulations regarding land and surface use of oil and gas operations, including “impacts to public facilities and services” and “all other nuisance-type effects of oil and gas development[.]”⁸⁹ Local governments are permitted to impose “more protective or stricter” regulations than those issued by the COGCC or other state agencies.⁹⁰ It is unclear whether local governments may promulgate less restrictive regulations than the COGCC. The Colorado Land Use Enabling Act gives local governments, defined as “a county, home rule or statutory city, town, territorial charter city, or city and county,”⁹¹ the authority to regulate “the location and siting of oil and gas facilities and oil and gas locations”⁹² Complementary provisions of Colorado’s OGCA require any operator seeking a state permit to first seek siting approval from the local government.⁹³ It is difficult to predict how Colorado courts will shape the new regulative authority held by local governments, although case law predating passage

⁸⁶ COLO. CONST. art. XX, § 6.

⁸⁷ City of Commerce City v. State, 40 P.3d 1273, 1279 (Colo. 2002).

⁸⁸ COLO. CONST. art. XIV, § 16.

⁸⁹ COLO. REV. STAT. ANN. § 29-20-104 (West 2020); COLO. REV. STAT. ANN. § 34-60-131 (West 2020); see 2019 Colo. SB 181 (West).

⁹⁰ § 34-60-131.

⁹¹ COLO. REV. STAT. ANN. § 29-20-103(1.5) (West 2020).

⁹² § 29-20-104(1)(h)(II).

⁹³ COLO. REV. STAT. ANN. § 34-60-116(1)(b)(II) (West 2020).

of 19-181 indicates that a total ban on any drilling activities would likely be preempted. Cities and counties are currently undergoing rulemaking regarding oil and gas operations while the COGCC is navigating the new processes through separate rulemaking proceedings. Thus, accurate predictions regarding judicial treatment of the new oil and gas regulatory power granted to local governments are not feasible.

Tribal Lands

Two federally recognized tribes lie within the State of Colorado, both of which have independent reservations situated in the southwest corner of the state: the Ute Mountain Ute Tribe and the Southern Ute Indian Tribe.⁹⁴ These two reservations are comprised of a combined 882,838 acres.⁹⁵ The larger of the two reservations belongs to the Ute Mountain Ute Tribe, which encompasses 575,000 contiguous acres and extends into portions of New Mexico and Utah.⁹⁶ The Southern Ute Indian Tribe's reservation is a checkerboard reservation encapsulating 307,838 Tribally-owned acres.⁹⁷

Operations on tribal land may be subject to both tribal law and BIA administration. The EPA maintains primacy for the UIC program on all tribal lands in Colorado.⁹⁸ The Southern Ute Indian Tribe has an intergovernmental agreement with the state of Colorado to implement a reservation air quality program consistent with EPA requirements and the Clean Air Act.⁹⁹ The Reservation Air Code defines carbon dioxide as a greenhouse gas and grants the Southern Ute Indian Tribe/State of Colorado Environmental Commission (Environmental Commission) authority to promulgate rules and administer an air quality permitting program.¹⁰⁰ The Land Division of the Southern Ute Department of Energy is “responsible for processing all Tribal Trust related oil and gas leases, rights-of-way, surface leases and associated conveyances as well as processing applications for permission to drill new wells” only when the Tribe is the mineral owner.¹⁰¹

The Ute Mountain Ute Reservation requires that proposed pipelines receive authorization from both

⁹⁴ See COLORADO COMMISSION OF INDIAN AFFAIRS, TRIBES (2019), <https://www.colorado.gov/pacific/ccia/tribes>.

⁹⁵ See *id.*

⁹⁶ COLORADO COMM. OF INDIAN AFFAIRS, TRIBES: UTE MOUNTAIN UTE TRIBE (2019), <https://www.colorado.gov/pacific/ccia/ute-mountain-ute-tribe>.

⁹⁷ COLORADO COMM. OF INDIAN AFFAIRS, TRIBES: SOUTHERN UTE INDIAN TRIBE (2019), <https://www.colorado.gov/pacific/ccia/southern-ute-indian-tribe>.

⁹⁸ 40 C.F.R. 147.301 (2020).

⁹⁹ COLO. REV. STAT. ANN. § 24-62-101 (West 2020).

¹⁰⁰ *Id.*

¹⁰¹ S. UTE DEP'T OF ENERGY LAND DIV., <https://www.suitdoe.com/land-division/> (last visited June 21, 2020).

the BIA and the BLM for easements and rights-of-way.¹⁰² However, there are currently no CO₂ pipelines on the Ute Mountain Ute Reservation.¹⁰³ For the purpose of protecting the Tribe's water resources, an Army Corps of Engineers permit is also required.¹⁰⁴

Eminent Domain:

Authority for eminent domain in Colorado is derived from statutory¹⁰⁵ and constitutional provisions. The Constitution of the State of Colorado authorizes condemnation of private property for private use exclusively “for private ways of necessity, and... for reservoirs, drains, flumes or ditches on or across the lands of others, for agricultural, mining, milling, domestic or sanitary purposes.”¹⁰⁶ In *Akin v. Four Corners Encampment*, the Colorado Court of Appeals interpreted this language to be inapplicable in cases involving private takings by a pipeline company for “private ways of necessity.”¹⁰⁷ Instead, the court held that the public use and just compensation requirements of Art. 2, § 15 apply to condemnations for pipeline construction.¹⁰⁸

Colorado has statutorily vested common carrier pipeline companies with eminent domain authority.¹⁰⁹ Colo. Rev. Stat. § 38-4-102 provides common carriers with eminent domain authority “for the transmission of power, water, air, or gas for...public purpose.” In 2012, the Colorado Supreme Court held that eminent domain authority of pipeline companies was limited to “specific substances” by the statute and does not extend to petroleum pipelines.¹¹⁰ Our research did not reveal precedent interpreting whether CO₂ would qualify as “gas” for purposes of this eminent domain statute.

Before a common carrier pipeline company may exercise eminent domain authority, it must consider using existing utility rights-of-way, demonstrate to a court that the particular land sought lies within the most direct route practicable, and post a bond equal to double the amount which the court determines to be the estimated cost of reclamation of the land.¹¹¹

¹⁰² Personal communication with Scott Clow, Ute Mountain Ute Environmental Program (June 6, 2020).

¹⁰³ *Id.*

¹⁰⁴ *Id.*

¹⁰⁵ COLO. REV. STAT. ANN. §§ 38-1-101 to 38-7-107 (West 2020).

¹⁰⁶ COLO. CONST. art. II, § 14.

¹⁰⁷ *Akin v. Four Corners Encampment*, 179 P.3d 139, 144 (Colo. App. 2007), *cert. denied*, 2008 WL 555690 (Colo. 2008).

¹⁰⁸ See *Akin*, 179 P.3d at 145-146; see also COLO. CONST. art. II, § 15.

¹⁰⁹ See COLO. REV. STAT. ANN. § 38-5-105 (West 2020); See also COLO. REV. STAT. ANN. § 38-1-202(2)(b) (West 2020) (stating a “pipeline company” is one which is “authorized in article 5 of this title and sections 7-43-102, 34-48-105, 34-48-111, 38-1-101.5, 38-1-101.7, 38-2-101, 38-4-102, and 38-4-107, C.R.S.”);

¹¹⁰ *Larson v. Sinclair Transportation Co.*, 284 P.3d 42, 45 (Colo. 2012), *rehearing denied* (2012).

¹¹¹ COLO. REV. STAT. ANN. § 38-1-101.5(1) (West 2020). There are

Geologic CO₂ Storage Regulation and Incremental Storage:

Our research revealed no statutes in Colorado specifically relating to geologic or incremental storage. The COGCC directive covers only incidental CO₂ storage for EOR purposes.¹¹² While the Colorado legislature has considered long-term carbon sequestration legislation, it has not enacted any laws. Similarly, Colorado has neither legislatively nor judicially determined whether an action for trespass lies in subsurface migration or escape of CO₂. If the matter arises, we speculate that a Colorado court would likely impose liability for injected CO₂ on the injector based on an analog to either its statutes for oil and gas operations or natural gas storage. Following either avenue will find that the injector retains ownership of and liability for injected CO₂.



“While the Colorado legislature has considered long-term carbon sequestration legislation, it has not enacted any laws. ”

additional requirements for release of a surface damage bond if the land is used for productive agricultural purposes or lies adjacent to or in proximity to federal land of comparable use. *See*, COLO. REV. STAT. ANN. § 38-1-101.5(1)(b) (West 2020).

¹¹² 2 COLO. CODE REGS § 404-1:401 (West 2020).

ILLINOIS

Executive Summary

Illinois has one of the most extensive statutory frameworks for CO₂ transport, utilization, and storage in the eastern United States. Two large CO₂ sequestration projects have been developed in Illinois. The first, the Illinois Industrial Carbon Capture and Storage Project, has captured CO₂ from an ethanol production facility, and has injected over 1MT into the Mount Simon formation at Decatur, Illinois. The second, the FutureGen project, was intended to demonstrate capture and sequestration from a coal-fired generation station. Although the FutureGen project was abandoned in 2015, its development likely encouraged the state legislature to address regulatory issues associated with geologic carbon storage. For instance, Illinois law specifically defines and regulates CO₂ pipelines. However, neither courts nor the legislature have addressed ownership or unitization of pore space rights, though proposed legislation directly addresses this issue. Municipalities in Illinois have considerable power in the permitting and regulation of industrial and subsurface activities. In Illinois, it appears that state regulations do not preempt local and municipal government regulation.

Background:

Of Illinois' 35,579,500 acres, 430,880 acres (1.21%) is owned by the federal government, while the state government owns 405,900 acres (1.19%) of the state. There are no tribal lands in Illinois.

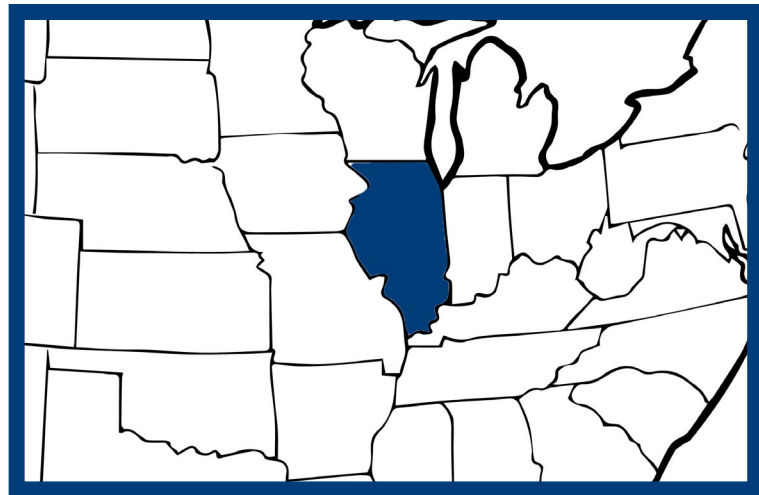
Illinois' court system consists of three levels: circuit, appellate, and supreme. Illinois has 24 circuits, each with their respective circuit court. Circuit courts hold original (trial) jurisdiction over most cases. The appellate court consists of five geographic districts and hears appeals from circuit courts within the district and the Illinois Workers' Compensation Council. Finally, the Illinois Supreme Court hears appeals from the appellate courts.

CO₂-EOR in Illinois:

Illinois has a long history of oil production, with production peaking in the 1940s, and is currently the 16th highest producing state, although at a relatively low rate. Natural gas production is also relatively low, ranked 25th in the country.¹ Illinois has a history of enhanced recovery, including waterflooding and CO₂-EOR,² and

¹ Profile Overview, U.S. ENERGY INFORMATION, Illinois, <https://www.eia.gov/state/?sid=IL>.

² ADVANCED RESOURCES INTERNATIONAL, BASIN ORIENTED STRATEGIES FOR CO₂ ENHANCED OIL RECOVERY: ILLINOIS & MICHIGAN BASINS (Feb. 2006).



has an abundance of relatively low-cost CO₂, including from biogenic sources, and large fields suitable for CO₂-EOR.

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Ownership

In Illinois, courts construe a contract as a whole, scrutinizing the language used to determine the intention of the parties, and then construct the contract to enforce that intention.³ Oil and gas leases are subject to the same rules of interpretation as any other contract.⁴

An express reservation of oil and gas in a grant or deed to a third person may create a separate estate in the oil and gas beneath the surface.⁵ Unlike a mineral deed, an oil and gas lease does not create a separate taxable estate,⁶ but an oil and gas lease that grants the right to explore and take oil is considered a “freehold estate” in land in Illinois.⁷ The lessee’s obligation to drill and operate wells⁸ with “reasonable diligence” is implied in an oil and gas

³ See generally *Leavers v. Cleary*, 75 Ill. 349, 353 (1874).

⁴ See generally *O'Donnell v. Snowden & McSweeney Co.*, 149 N.E. 253, 255, 318 Ill. 374 (1925) (citing *Hammett Oil Co. v. Gypsy Oil Co.*, 95 Okl. 235 (1921)).

⁵ *Urdike v. Smith*, 39 N.E.2d 325, 328, 378 Ill. 600 (1942).

⁶ *Pickens v. Adams*, 131 N.E.2d 38, 43, 7 Ill. 2d 283 (1955) (citing *People ex rel. Hargrave v. Phillips*, 67 N.E.2d 281, 394 Ill. 119 (1946)).

⁷ See generally *Triger v. Carter Oil Co.*, 23 N.E.2d 55, 372 Ill. 182 (1939); *Carter Oil Co. v. Liggett*, 21 N.E.2d 569, 371 Ill. 482 (1939); *Greer v. Carter Oil Co.*, 25 N.E.2d 805, 373 Ill. 168 (1940) (a “freehold estate” is any estate of inheritance or for life in either a corporeal item of inheritance, like land or a building, or incorporeal item of inheritance, like rent or rights-of-way, existing in or arising from real property of free tenure).

⁸ *Simpson v. Adkins*, 53 N.E.2d 979, 984, 386 Ill. 64 (1944).

lease, so long as the enterprise is profitable,⁹ especially when the lessor has a royalty interest.¹⁰ However, the lease will not be forfeited if the product being drilled for cannot be marketed.¹¹

Illinois regards mineral ownership as “the ownership of land, for all intents and purposes,” once properly severed from the surface.¹² Accordingly, “mines are land, and subject to the same laws of possession and conveyance.”¹³ A mining lease only provides the lessee with the right to find and reduce minerals to possession.¹⁴ The lessor retains title so long as the minerals remain in the land, with the lessee paying the reserved royalty or rent on only the minerals he finds and possesses.¹⁵

Illinois adheres to the ownership theory.¹⁶ Before being separated from the land, oil is a “mineral” that belongs to the owner of the land.¹⁷ Coal, limestone, and other minerals similarly in place are “land” and are attributed with the characteristics of land ownership.¹⁸ Unlike Pennsylvania, Illinois generally includes petroleum in a grant of minerals.¹⁹ Illinois courts recognize the necessity of different rules for liquid and gaseous minerals versus those applied to solid minerals due to the difference in how they act.²⁰ Accordingly, oil and gas in place are

⁹ Elliott v. Pure Oil Co., 139 N.E.2d 295, 299, 10 Ill. 2d 146 (1956).

¹⁰ Baker v. Collins, 194 N.E.2d 353, 355, 29 Ill. 2d 410 (1963) (citing Elliott, 139 N.E.2d 295).

¹¹ Poe v. Ulrey, 84 N.E. 46, 50, 233 Ill. 56 (1908).

¹² See generally Caldwell v. Fulton, 31 Pa. 475 (1858); Caldwell v. Copeland, 37 Pa. 427 (1860); Scranton v. Phillips, 94 Pa. 15 (1880); Sanderson v. City of Scranton, 105 Pa. 469 (1888); Railroad Co. v. Sanderson, 109 Pa. 583 (1885).

¹³ See generally Caldwell, 31 Pa. 475 (1858) (a “mine” is the excavation of earth to obtain minerals and to take out some useful product, and a “mining right” the right to excavate).

¹⁴ Cent. Pipe Line Co. v. Hutson, 82 N.E.2d 624, 625, 401 Ill. 447 (1948) (citing Updike v. Smith, 39 N.E.2d 325, 378 Ill. 600, (1942); Triger v. Carter Oil Co., 23 N.E.2d 55, 372 Ill. 182 (1939)).

¹⁵ People ex rel. Hargrave v. Phillips, 67 N.E.2d 281, 283, 394 Ill. 119 (1946). See also People ex rel. Carrell v. Bell, 86 N.E. 593, 237 Ill. 332 (1908); Poe v. Ulrey, 84 N.E. 46, 233 Ill. 56 (1908); Triger v. Carter Oil Co., 23 N.E.2d 55, 372 Ill. 182 (1939); Updike v. Smith, 39 N.E.2d 325, (Ill. 1942).

¹⁶ Updike, 39 N.E.2d at 327-28.

¹⁷ See generally Ohio Oil Co. v. Daughetee, 88 N.E. 818, 240 Ill. 361 (1909); People ex rel. Carrell v. Bell, 86 N.E. 593, 237 Ill. 332 (1908); Poe v. Ulrey, 84 N.E. 46, 233 Ill. 56 (1908); Triger v. Carter Oil Co., 23 N.E.2d 55, 372 Ill. 182 (1939); Ohio Oil Co. v. State, 177 U.S. 190 (1900); Burke v. Southern Pacific R. Co., 234 U.S. 669 (1914).

¹⁸ See Kinder v. La Salle Cty. Carbon Coal Co., 133 N.E. 772, 773, 301 Ill. 362 (1921).

¹⁹ See generally Appeal of Stoughton, 88 Pa. 198 (1878); Murray v. Allred, 100 Tenn. 100, 43 S.W. 355 (1897); Gill v. Weston, 110 Pa. 312 (1885); Williamson v. Jones, 39 W. Va. 231, 19 S.E. 436 (1894); Wilson v. Youst, 43 W. Va. 826, 28 S.E. 781 (1897); Kelly v. Ohio Coal Co., 57 Ohio. St. 317, 49 N.E. 399 (1897); Blakely v. Marshall, 174 Pa. 425 (1896).

²⁰ See generally People ex rel. Carrell v. Bell, 86 N.E. 593, 594, 237

“minerals,” but “cannot be subject of ownership distinct from soil” due to their fugacious nature, and belong to the landowner only so long as they remain in place under the land.²¹ Illinois follows the non-ownership theory of oil and gas resources.²²

Illinois courts consider not only the soil and the minerals beneath real estate,²³ but also the incorporeal rights attached to or growing out of the soil,²⁴ such as rights-of-way and easements.²⁵ A “mineral deed” conveys real estate, whether it actually severs mineral rights from those of the surface or if it conveys the right to search and possess only a portion of the underlying mineral.²⁶ In addition to title to solid minerals, a mineral deed grants the right to enter, explore, and reduce to possession the fluid minerals of oil and gas²⁷ since title to oil and gas does not vest until found and reduced to possession²⁸

An oil and gas lease of indefinite duration does not operate as a severance of oil and gas rights from those of the surface.²⁹ Rather, the freehold estate created by such a lease exists only insofar as the prospecting for oil and gas granted in the lease is concerned.³⁰ No title is conveyed until the oil and gas are found and reduced to possession.³¹ The interest is extinguished when the purpose is accomplished and the work abandoned,³² which Illinois defines as the “cessation of operations for an unreasonable length of time.”³³

Ill. 332 (1908) (citing Watford Oil & Gas Co. v. Shipman, 84 N.E. 53, 233 Ill. 9 (1908)).

²¹ See Updike v. Smith, 39 N.E.2d 325, 327 (Ill. 1942).

²² See generally Bruner v. Hicks, 230 Ill. 536, 542 (1907) (“It may be conceded that title to the oil and gas in said lands did not vest . . . until the oil and gas were discovered and appropriated . . .”).

²³ See Manning v. Frazier, 96 Ill. 279, 285 (1880).

²⁴ See generally Texas Co. v. O’Meara, 377 Ill. 144, 149, 36 N.E.2d 256 (1941); Tallman v. Eastern Illinois & Peoria Railroad Co., 379

Ill. 441, 41 N.E.2d 537 (1942); Oswald v. Wolf, 126 Ill. 542, 19 N.E. 28 (1888).

²⁵ See Texas Co., 36 N.E.2d at 258.

²⁶ See Jilek v. Chicago, Wilmington & Franklin Coal Co., 47 N.E.2d 96, 99, 382 Ill. 241 (1943) (quoting Updike, 39 N.E.2d 325).

²⁷ Pickens v. Adams, 131 N.E.2d 38, 43, 7 Ill. 2d 283 (1955) (citing Triger v. Carter Oil Co., 23 N.E.2d 55, 372 Ill. 182 (1939); Poe v. Ulrey, 84 N.E. 46, 233 Ill. 56 (1908)).

²⁸ See Updike, 39 N.E.2d 325, 327 (Ill. 1942) (citing Watford Oil & Gas Co. v. Shipman, 84 N.E. 53, 233 Ill. 9 (1908) (“reduced to possession” refers to the mineral being used or marketed).

²⁹ Updike, 39 N.E.2d at 327-28. See also Fowler v. Marion & Pittsburg Coal Co., 146 N.E. 318, 319, 315 Ill. 312 (1924).

³⁰ See Deverick v. Bline, 89 N.E.2d 43, 45, 404 Ill. 302 (1949) (citing Watford Oil & Gas Co. v. Shipman, 233 Ill. 9, 84 N.E. 53 (1908)).

³¹ *Id.*

³² *Id.*

³³ See Spies v. De Mayo, 72 N.E.2d 316, 325 396 Ill. 255 (1947) (an “unreasonable length of time” is determined on a case-by-case basis).

Split Estates

There is no complete severance of oil and gas rights from the surface if the same owner possesses title to both surface and any part of the underlying oil and gas.³⁴ Severance is achieved whether a fractional, undivided interest in the minerals has been conveyed or reserved.³⁵ Reservation of the surface rights in a conveyance of the mineral rights creates two separate estates: surface and mineral.³⁶ Each estate is then considered “real estate”³⁷ and is thus alienable and subject to taxation.³⁸ As real estate, once the rights to a mineral have been conveyed, the rights may pass by inheritance or by deed of conveyance.³⁹

The owner of a mineral estate possesses a freehold estate in real estate separate from that of the surface estate.⁴⁰ When a fractional, undivided interest in minerals is either conveyed or reserved, the grantor and grantee become tenants in common of the mineral estate, even though one may own the surface estate.⁴¹ Where two or more people share ownership rights in the mineral estate, they become tenants in common who are entitled to a partition.⁴² Similarly, as freehold estates, mining claims⁴³ and mineral rights in land⁴⁴ are also subject to partition.

The means of enjoying the mineral estate pass without an express agreement when the mineral estate is severed from the surface.⁴⁵ The mineral estate essentially carries with it “the right to use so much of the surface of the land as may be necessary to enforce and enjoy the estate reserved.”⁴⁶ As a matter of law, the surface owner is entitled to subjacent (underlying) support, and this right of support is absolute and unconditional.⁴⁷ If removal of the mineral deprives the surface owner of subjacent

support and liability has not been expressly waived, the mineral estate owner is liable for any subsidence of the surface resulting from mineral removal.⁴⁸ Even if the most approved form of mining is employed in the removal of the mineral, the surface owner is still due support⁴⁹

“If removal of the mineral deprives the surface owner of subjacent support and liability has not been expressly waived, the mineral estate owner is liable for any subsidence of the surface resulting from mineral removal.”

sufficient to maintain the surface in its natural state.⁵⁰

Illinois enacted the Drilling Operations Act⁵¹ to provide surface owners with reasonable compensation after cessation of production.⁵² This act is only applicable when the surface owner has *not* consented in writing to the drilling operations and there has either been: a complete severance of the oil/gas/coalbed methane from the surface, or where the owner has an interest in the oil/gas/coalbed methane, which is the subject of either an integration proceeding or a proceeding brought pursuant to “an Act in relation to oil and gas interest in land.”⁵³ The statute entitles the surface owner to reasonable compensation based on subsequent damages to growing crops, trees, shrubs, fences, roads, structures, improvements, personal property, and livestock caused by drilling operations,⁵⁴ as well as the loss of value of a commercial crop⁵⁵ and all negligent acts that cause measurable damage to the productive capacity of the soil.⁵⁶ Compensation may be paid in any matter mutually agreed upon by the operator and surface owner.⁵⁷ The failure to agree or make the compensation required does *not* prevent the operator from drilling operations, provided that the compensation is

⁴⁸ *Jilek v. Chicago, Wilmington & Franklin Coal Co.*, 47 N.E.2d 96, 101, 382 Ill. 241 (1943) (citing *Wilms v. Jess*, 94 Ill. 464 (1880)); *Lloyd*, 71 N.E. 335, 210 Ill. 460 (1904)).

⁴⁹ *Lloyd*, 71 N.E. at 339, .

⁵⁰ *Shell Oil Co. v. Moore*, 48 N.E.2d 400, 403, 382 Ill. 556 (1943) (quoting *Wilms v. Jess*, 94 Ill. 464 (1880)).

⁵¹ 765 ILL. COMP. STAT. ANN. 530/1 et seq (West 2020).

⁵² 765 ILL. COMP. STAT. ANN. 530/6 (West 2020).

⁵³ See 765 ILL. COMP. STAT. ANN. 530/3 (West 2020).

⁵⁴ 765 ILL. COMP. STAT. ANN. 530/6(A)(1) (West 2020).

⁵⁵ 765 ILL. COMP. STAT. ANN. 530/6(A)(3) (West 2020).

⁵⁶ 765 ILL. COMP. STAT. ANN. 530/6(A)(4) (West 2020).

⁵⁷ 765 ILL. COMP. STAT. ANN. 530/6(B) (West 2020).

³⁴ See *Updike v. Smith*, 39 N.E.2d 325, 328 (Ill. 1942).

³⁵ See *Uphoff v. Trustees of Tufts Coll.*, 184 N.E. 213, 216, 351 Ill. 146 (1932) (citing *Gill v. Fletcher*, 74 Ohio. St. 295, 78 N.E. 433 (1906); *Preston v. White*, 57 W. Va. 278, 50 S.E. 236 (1905); *South Penn Oil Co. v. Haught*, 71 W. Va. 720, 78 S.E. 759 (1913)).

³⁶ *Catlin Coal Co. v. Lloyd*, 52 N.E. 144, 146, 176 Ill. 275 (1898) (citing *Major v. Pavey*, 24 N. E. 973, 134 Ill. 19 (1890)).

³⁷ See *Catlin Coal Co.*, 52 N.E. 144, 176 Ill. 275 (1898); *Renfro v. Hanon*, 130 N.E. 740, 297 Ill. 353 (1921); *Transcontinental Oil Co. v. Emmerson*, 131 N.E. 645, 298 Ill. 394 (1921)).

³⁸ See *Catlin Coal Co.*, 52 N.E. at 146 (citing *Major v. Pavey*, 24 N.E. 973, 134 Ill. 19 (1890)).

³⁹ *Manning v. Frazier*, 96 Ill. 279, 285 (1880).

⁴⁰ See *Pickens v. Adams*, 131 N.E.2d 38, 43, 7 Ill. 2d 283 (1955) (citing *McConnell v. Pierce*, 210 Ill. 627, 71 N.E. 622 (1904)).

⁴¹ *Uphoff v. Trustees of Tufts Coll.*, 351 Ill. 146, 154, 184 N.E. 213, 216 (1932).

⁴² *Brand v. Consol. Coal Co.*, 76 N.E. 849, 850, 219 Ill. 543 (1906) (citing *McConnell v. Pierce*, 71 N.E. 622, 210 Ill. 627 (1904)).

⁴³ *McConnell*, 71 N.E. at 625.

⁴⁴ *Id.*

⁴⁵ See *Threlkeld v. Inglett*, 124 N.E. 368, 289 Ill. 90 (1919); *Chicago, Rock Island & Pacific Railway Co. v. Smith*, 111 Ill. 363 (1884).

⁴⁶ See *Miller v. Ridgley*, 117 N.E.2d 759, 763, 2 Ill. 2d 223 (1954).

⁴⁷ See *Lloyd v. Catlin Coal Co.*, 71 N.E. 335, 338, 210 Ill. 460 (1904).

paid no later than 90 days after completion of the well.⁵⁸ If the operator fails to pay within the 90-day period, or if the amount is not reasonable, the surface owner may file a claim for compensation in the circuit court where the lands are located, or where drilling operations were conducted, with compensation and attorney's fees owed to the surface owner.⁵⁹ However, if the operator relies on a third-party appraisal or fair market value, the amount is deemed to be reasonable and no award of attorney's fees will be granted.⁶⁰ The operator must also restore the surface to a condition *as near as practicable* to the condition of the surface prior to the commencement of drilling operations, provided the surface owner did not waive this requirement in writing.⁶¹

Pore Space Ownership

The Illinois regulatory framework is unresolved with regards to pore space ownership. However, in 2010 the legislature established a Carbon Capture and Sequestration Legislation Commission to present a report on pore space ownership.⁶² In March of 2020, the legislature contemplated a bill that, in the context of carbon sequestration, vests pore space ownership in the surface owner. This bill also prohibits the severance of the pore space estate and instead sanctions the leasing of the estate.⁶³ This bill has not yet advanced beyond the House's Energy & Environment Committee.⁶⁴

Water Rights

Riparian rights govern surface water in Illinois.⁶⁵ Illinois courts distinguish between use for "natural wants" and "artificial wants."⁶⁶ Natural wants are "absolutely necessary" to one's existence, and include such uses as drinking, bathing, cooking, and the like.⁶⁷ Artificial wants are nonessential and include such uses as irrigation and manufacturing.⁶⁸ During periods of deficiency, natural users prevail over artificial users.⁶⁹ However, each user is entitled to a reasonable proportion of the water in cases involving competing artificial users.⁷⁰

⁵⁸ *Id.* (emphasis added).

⁵⁹ *Id.*

⁶⁰ *Id.*

⁶¹ 765 ILL. COMP. STAT. ANN. 530/6(C) (West 2020) (emphasis added).

⁶² Stefanie L. Burt, *Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions*, 4 JOULE: DUQ. ENERGY & ENVTL. L.J. 1 (2016).

⁶³ See H.B. 4370, 101st Gen. Assemb. 2d Reg. Sess. (Ill. 2020).

⁶⁴ Bill Status of HB4370, 101st Gen. Assemb. 2d Reg. Sess. (Ill. 2020), <https://www.ilga.gov/legislation/billstatus.asp?DocNum=4370&GAID=15&GA=101&DocTypeID=HB&LegID=123677&SessionID=108>.

⁶⁵ *Evans v. Merriweather*, 4 Ill. 492 (1842).

⁶⁶ *Id.* at 495.

⁶⁷ *Id.* at 495-96.

⁶⁸ *Id.*

⁶⁹ *Id.* at 496.

⁷⁰ *Id.*

With respect to groundwater rights, Illinois courts applied the absolute dominion rule as recently as 1981.⁷¹ However, the Water Use Act of 1983 adopted the reasonable use rule for groundwater, superseding the previous common law regime.⁷² No permits are required for withdrawals, but local soil and water conservation districts may recommend restrictions on withdrawals to the Illinois Department of Agriculture in order to preserve an adequate water supply during water emergencies.⁷³

"Produced water" is water that is produced in conjunction with oil or natural gas production or storage operations.⁷⁴ Surface discharge of produced water onto the ground, into any surface water, or water drainage way, is prohibited.⁷⁵ Produced water may only be disposed of by injection into a Class II well that is below interface between fresh water and naturally occurring Class IV groundwater⁷⁶ or by injection in a permitted enhanced oil recovery operation.⁷⁷ Permittees must submit an annual produced water report to the Illinois Department of Natural Resources, detailing the management of any produced water that is associated with any permitted well.⁷⁸ The Illinois Hydraulic Fracturing Regulatory Act provides for additional disposal requirements for hydraulic fracturing flowback.⁷⁹

Lithium Ownership and Extraction

Our research did not reveal any statutes or cases specifically contemplating lithium extraction. The most relevant reference to lithium in the Illinois regulatory scheme is that lithium is exempted as a regulated metal powder used during the metal forming process.⁸⁰

Classification of CO₂: Commodity and Pollutant

Illinois is significant because it has active statutes regulating CO₂ in the context of enhanced oil recovery, saturation, and pipelines.⁸¹ These statutes regulate the production and transportation of CO₂ as a commodity. Additionally, some CO₂ may be taxable as a commodity. Gas produced in wells involving high-volume horizontal hydraulic fracturing and "taken from below the surface of the earth," including CO₂, is subject to taxation as a

⁷¹ See generally *Edwards v. Haeger*, 54 N.E. 176, 176, 180 Ill. 99 (1899); *Lee v. City of Pontiac*, 426 N.E.2d 300, 302, 99 Ill. App.3d 982 (1981).

⁷² 525 ILL. COMP. STAT. ANN. 45/3(c) (West 2020). See also *Bridgeman v. Sanitary Dist.*, 517 N.E.2d 309, 164 Ill. App.3d 287 (1987).

⁷³ 525 ILL. COMP. STAT. ANN. 45/5.1 (West 2020).

⁷⁴ See generally 225 ILL. COMP. STAT. ANN. § 732/1-5 (West 2020).

⁷⁵ See ILL. ADMIN. CODE tit. 62, § 245.940(a) (2020).

⁷⁶ ILL. ADMIN. CODE tit. 62, § 245.940(b) (2020).

⁷⁷ 225 ILL. COMP. STAT. ANN. 732/1-75(c)(8) (West 2020).

⁷⁸ See ILL. ADMIN. CODE tit. 62, § 245.940(f)(1)-(2) (2020).

⁷⁹ 225 ILL. COMP. STAT. ANN. 732/1-75(c)(8) (West 2020).

⁸⁰ ILL. ADMIN. CODE tit. 35, § 307.8100 (West 2020).

⁸¹ See generally 220 ILL. COMP. STAT. ANN. 75/5 et seq. (West 2020).

commodity pursuant to the Illinois Hydraulic Fracturing Tax Act.⁸² However, the act specifically excludes “gas injected into the earth for the purpose of lifting oil, recycling, or repressuring.”⁸³

Although CO₂ is recognized as a commodity, most statutes regulate CO₂ as a pollutant or safety concern. For example, statutory authority allows “clean coal SNG brownfield” facilities to recover costs of operating CO₂ sequestration sites, and includes references to CO₂ as a pollutant, with discussions of CO₂ emission credits.⁸⁴ Illinois has a carbon sequestration siting program that requires permits before the operation of a CO₂ sequestration system, and the profits from permit applications are deposited to the Environmental Protection Permit and Inspection Fund.⁸⁵ This statute is located under Title III of the Environmental Protection Act of Illinois.⁸⁶ Illinois also has a statute demanding proper construction, maintenance, and operation of pipelines transporting carbon dioxide, naming safety considerations as the purpose of the statute.⁸⁷

A permittee seeking approval from the Illinois Environmental Protection Agency for an underground injection carbon sequestration site is liable to the agency for all “reasonable and documented costs incurred by the Agency” during the application process and all reasonable and documented costs associated with inspection and oversight of carbon sequestration site.⁸⁸ Regulation that applies only to the FutureGen project in the Mount Simon Formation prescribes the operator with all right, title, interest, and any liability associated with the sequestered CO₂ during the operations of the project, plus an additional 10-year period.⁸⁹ Additionally, the operator shall transfer and convey and the State of Illinois shall accept and receive, with not payment due from the State of Illinois, all rights, title, and interest, including any future environmental benefits or credits, in and to and any liability associated with sequestered CO₂.⁹⁰

In additional regulations applying only to the FutureGen project, the state commits to indemnify the operator of a carbon sequestration site against any public liability so long as the operator’s actions do not constitute “intentional or willful misconduct,” a failure to “materially comply with any applicable law, rule, regulation or other requirement,” an operator’s “pre-

injection activities.”⁹¹ A “qualified loss to the extent that it is equal to or less than \$100,000,000 or is covered by the combination of funds in an insurance policy under subsection (a) of Section 25 of this act, funds in the CO₂ Storage Fund under subsection (b) of Section 25 of this Act, project assets, and cash or cash equivalents.”⁹² Illinois enacted the Clean Coal FutureGen for Illinois Act of 2011 (Act) to support the FutureGen Project.⁹³ While the FutureGen project was abandoned, these rules provide good examples for implementable rules and indicates the viability of legislative approaches to regulation of CO₂ utilization and storage.

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

Chapter 225, Section 725 of the Illinois Compiled Statutes contains conservation laws for oil and gas resources.⁹⁴ The Illinois Hydraulic Fracturing Regulatory Act, Chapter 225, Section 732, provides additional authority to regulate wells where high-volume, horizontal hydraulic fracturing is planned or has occurred.⁹⁵ These laws are enforced by the Illinois Department of Natural Resources (“ILDNR”) and its Director. The Director appoints members to a seven-member Oil and Gas Board (“Board”) which must consist of six members representing the various interests in the oil and gas industry and one member representing the state’s agricultural industry.⁹⁶ The Board may make recommendations to the ILDNR on many oil and gas matters in Illinois, but the Board is strictly advisory, so none of the recommendations are binding.⁹⁷ The ILDNR must present any new rule or changes to existing rules to the Board, and if the Board unanimously opposes the proposed rule, the ILDNR must publish the Board’s objection in detail in the notice of proposed rulemaking.⁹⁸

The ILDNR has the authority to conduct hearings and make rules regarding the regulations of well spacing, the establishment of drilling units, and the issuing of permits.⁹⁹ The provisions of this Illinois Oil and Gas Act are retroactive, and all unpermitted wells prior to the act and its amendments must be permitted.¹⁰⁰ The ILDNR has the authority to issue subpoenas for records and the

⁸² 35 ILL. COMP. STAT. ANN. 450/2-5 (West 2020).

⁸³ 35 ILL. COMP. STAT. ANN. 450/2-15(d) (West 2020).

⁸⁴ 220 ILL. COMP. STAT. ANN. 5/9-220 (West 2020).

⁸⁵ 415 ILL. COMP. STAT. ANN. 5/13.7 (West 2020).

⁸⁶ 415 ILL. COMP. STAT. ANN. 5/13.7 (West 2020).

⁸⁷ 220 ILL. COMP. STAT. ANN. 75/30 (West 2020).

⁸⁸ 415 ILL. COMP. STAT. ANN. 5/13.7(d) (West 2020).

⁸⁹ 20 ILL. COMP. STAT. ANN. 1108/20 (West 2020).

⁹⁰ *Id.*

⁹¹ 20 ILL. COMP. STAT. ANN. 1108/30(a)(1)-(4) (West 2020).

⁹² 20 ILL. COMP. STAT. ANN. 1108/30(a)(1)-(4) (West 2020).

⁹³ *See* 20 ILL. COMP. STAT. ANN. 1108/1 et seq. (West 2020).

⁹⁴ 225 ILL. COMP. STAT. ANN. 725/1- 725/28.1 (West 2020).

⁹⁵ 225 ILL. COMP. STAT. ANN. 732/1- 732/140 (West 2020).

⁹⁶ 225 ILL. COMP. STAT. ANN. 725/1.2 (West 2020).

⁹⁷ *Id.*

⁹⁸ *Id.*

⁹⁹ 225 ILL. COMP. STAT. ANN. 725/6 (10) (West 2020).

¹⁰⁰ 225 ILL. COMP. STAT. ANN. 725/12 (West 2020).

attendance of witnesses at any proceeding conducted by the ILDNR.¹⁰¹ The ILDNR also adopts rules of procedure for hearings pursuant to the Illinois Administrative Procedure Act.¹⁰²

Any “interested person” can apply for a drilling unit.¹⁰³ Spacing in a unit is determined by the ILDNR, and a drilling unit must not “be smaller than the maximum area that can be efficiently and economically drained by one well” and each drilling unit order “shall cover all lands determined or believed to be underlaid by such pool.”¹⁰⁴ The ILDNR may modify any order after it has been issued to change the size or permit additional wells.¹⁰⁵

Owners of oil and gas interests may voluntarily agree to integrate their interests and to develop their lands as a drilling unit.¹⁰⁶ Where no voluntary agreement exists, and where at least one owner proposes to drill a well on an established unit, the ILDNR shall order the integration of interests and may prescribe the terms and conditions upon royalty interests, upon application from an owner.¹⁰⁷ In the context of integrating interests in a pool suitable to enhanced recovery methods, two or more owners of separate tracts can validly agree to integrate their interests and develop their land as a unit, and production from any tract in an established unit “shall be regarded as production from all presently owned tracts or interests within such units.”¹⁰⁸ Upon a petition of an interested party, and after the ILDNR holds a required public hearing to consider the need for pooling to protect correlative rights and prevent waste, the ILDNR may order the forcible unitizing of a pool.¹⁰⁹ The petition for unitization must be signed by persons owning at least 51% of the working interest underlying the surface.¹¹⁰

Similarly, an order of the ILDNR for unitizing a pool must be approved in writing by “those persons who, under the order, will be required to pay at least 51% of the unit expense, and also by the person owning at least 51% of the unit production or proceeds thereof that will be credited to interests which are free of unit expense.”¹¹¹ However, if only one person is required to pay at least 51% but less than 100% of unit production expenses, the order must be approved “by one other such person.”¹¹²

¹⁰¹ 225 ILL. COMP. STAT. ANN. 725/4 (West 2020).

¹⁰² 225 ILL. COMP. STAT. ANN. 725/9 (West 2020).

¹⁰³ 225 ILL. COMP. STAT. ANN. 725/21.1(a) (West 2020).

¹⁰⁴ 225 ILL. COMP. STAT. ANN. 725/21.1(b) (West 2020).

¹⁰⁵ *Id.*

¹⁰⁶ See 225 ILL. COMP. STAT. ANN. 725/22.2(b) (West 2020).

¹⁰⁷ *Id.*

¹⁰⁸ 225 ILL. COMP. STAT. ANN. 725/23.2(a) (West 2020).

¹⁰⁹ 225 ILL. COMP. STAT. ANN. 725/23.3 (West 2020).

¹¹⁰ 225 ILL. COMP. STAT. ANN. 725/23.3(d) (West 2020).

¹¹¹ 225 ILL. COMP. STAT. ANN. 725/23.8 (West 2020).

¹¹² *Id.*

The same additional approval “by one other such person” is needed if only one person owns at least 51% but less than 100% of the unit production or proceeds.¹¹³

In Illinois, a subsurface trespass exists if the trespasser never obtains the right to enter below the surface of a property for any reason.¹¹⁴ In the context of oil and gas, if a well drilled at an angle reaches underneath and produces oil or gas from underneath the surface of another tract, a trespass occurs.¹¹⁵ The Illinois Appellate Court ruled that a court may order a directional subsurface survey to determine where the well bottoms, and whether the well constitutes a subsurface trespass.¹¹⁶

When the severance of minerals by trespass is negligent, the trespasser cannot subtract the cost of severing coal from damages award.¹¹⁷ However, costs can be subtracted in the case of an innocent trespass.¹¹⁸ In instances of a willful mining trespass, the trespasser will also be liable for punitive damages of up to \$500.¹¹⁹ A trespass claim under Illinois law requires showing that the conduct is either negligent or intentional *and* that conduct has resulted in an intrusion on the exclusive possession of the land.¹²⁰ Illinois federal courts require this to show more than a mere allegation of subsurface substance migration.¹²¹ Illinois follows the “rule of capture” regarding oil leases, which means that “gas that migrates from one property to another is subject to recovery and possession by the holder of the gas estate on the property to which the gas migrates.”¹²² Although this principle has been applied to oil and gas,¹²³ Illinois courts have yet to address whether the incidental trespass caused by hydraulic fracturing fluid crossing estate lines constitutes an actionable trespass.

¹¹³ *Id.*

¹¹⁴ See generally *City of Chicago v. Troy Laundry Machinery Co.*, 162 F. 678, 679 (7th Cir. 1908).

¹¹⁵ See generally *Texas Co. v. Hollingsworth*, 304 Ill. App. 607, 621 (Ill. App. 1940).

¹¹⁶ *Id.*

¹¹⁷ *Donovan v. Consolidated Coal Co. of St. Louis*, 58 N.E. 290, 291, 187 Ill. 28 (1900).

¹¹⁸ *Id.*

¹¹⁹ 765 ILL. COMP. STAT. ANN. 505/5 (West 2020).

¹²⁰ *Porter v. Urbana-Champaign Sanitary Dist.*, 604 N.E.2d 393, 397 (Ill. App. 1992) (emphasis added).

¹²¹ *Vill. of Depue, Ill. v. Viacom Int’l, Inc.*, No. 08-CV-1272, 2009 WL 1841582, at *9 (C.D. Ill. June 25, 2009).

¹²² *Cont’l Res. of Illinois, Inc. v. Illinois Methane, LLC*, 847 N.E.2d 897 (Ill. App. Ct. 2006).

¹²³ *Id.* See also *Pawnee Oil & Gas, Inc. v. Cty. of Wayne*, 751 N.E.2d 1268, 1269 (Ill. App. 2001).

Pipeline Regulation

The OPS inspects and enforces the pipeline safety regulations for interstate gas pipeline operators in Illinois.¹²⁴ OPS also inspects and enforces the pipeline safety regulations for intrastate and interstate hazardous liquid pipeline operators in the state.¹²⁵ Through certification by OPS, Illinois inspects and enforces the pipeline safety regulations for intrastate gas pipeline operators in the state.¹²⁶ The Pipeline Safety Division of the Illinois Commerce Commission performs this work.¹²⁷ The Illinois Gas Pipeline Safety Act governs pipeline safety in the state.¹²⁸ By letter dated December 10, 2019, OPS notified the state that its enforcement of Illinois' excavation damage prevention law was "adequate."¹²⁹

Illinois' Carbon Dioxide Transportation and Sequestration Act imposes additional requirements on the construction, operation, and siting of CO₂ pipelines.¹³⁰ It defines "carbon dioxide pipeline" as the in-state portion of a pipeline which is used solely for the purpose of transporting carbon dioxide "to a point of sale, storage, enhanced oil recovery, or other carbon management application."¹³¹ Under this Act, "transportation" refers to the physical movement of carbon dioxide by pipeline conduct for a person's personal use or account or for

another person's use or account.¹³² The Act establishes an application process for the issuance of a certificate of authority by an individual constructing or operating a pipeline to transport and sequester carbon dioxide "produced by a clean coal facility, by a synthetic natural gas facility, or by any other source that will result in the reduction of carbon dioxide emissions from that source."¹³³ Among the requirements, an applicant must be willing and able to comply with all applicable acts and regulations, and coordinate with the PHMSA, the U.S. Army Corps of Engineers, and the Illinois Department of Agriculture.¹³⁴ The application must propose a specific route for the pipeline or a project route width that identifies the areas in which the pipeline would be located,¹³⁵ and the route must be approved by the Illinois Commerce Commission.¹³⁶ Once approved and issued, the certificate grants authority to construct and operate a carbon dioxide pipeline as requested in the application and a limited grant of authority to take and acquire an easement in any property or interest in property for the "construction, maintenance, or operation of a carbon dioxide pipeline in the manner provided for the exercise of the power of eminent domain under the Eminent Domain Act."¹³⁷

Under Illinois' Public Utilities Act, a "common carrier by pipeline" refers to persons and corporations that own, operate, and manage, either directly or indirectly, equipment, facilities, or other property that is (1) to be used in connection with the conveyance of gas or liquids other than water for the general public in common carriage pipeline or (2) to be used in connection with the conveyance of water drawn from Lake Michigan for the general public in common carriage by pipeline.¹³⁸ However, gas public utilities and water public utilities that provide local distribution services are not common carriers by pipeline under the statute.¹³⁹ Common carriers by pipeline which are "owned and operated by any political subdivision, public institution of higher education or municipal corporation of this State, or common carriers by pipeline that are owned by such political subdivision, public institution of higher education, or municipal corporation and operated by any of its lessees or operating agents," is not a common carrier by pipeline under the statute.¹⁴⁰

Under the Act, all common carriers by pipeline must keep written accounts and records of all "revenues,

¹³² *Id.*

¹³³ 220 ILL. COMP. STAT. ANN. 75/15 (West 2020).

¹³⁴ *Id.*

¹³⁵ 220 ILL. COMP. STAT. ANN. 75/20(d) (West 2020).

¹³⁶ *Id.*

¹³⁷ 220 ILL. COMP. STAT. ANN. 75/20(h)(i) (West 2020).

¹³⁸ 220 ILL. COMP. STAT. ANN. 5/15-201 (West 2020).

¹³⁹ *Id.*

¹⁴⁰ *Id.*

"Illinois' Carbon Dioxide Transportation and Sequestration Act imposes additional requirements on the construction, operation, and siting of CO₂ pipelines."

¹²⁴ U.S. DEP'T OF TRANSP., PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., Regulatory Fact Sheet: Illinois (Jan. 9, 2017), https://primis.phmsa.dot.gov/comm/FactSheets/States/IL_State_PL_Safety_Regulatory_Fact_Sheet.htm.

¹²⁵ *Id.*

¹²⁶ *Id.*

¹²⁷ *Id.*

¹²⁸ 220 ILL. COMP. STAT. ANN. 20/1 (West 2020).

¹²⁹ See Letter from Alan K. Mayberry, Associate Administrator for Pipeline Safety, to Carrie Zalewski, Illinois Commerce Commission (Dec. 10, 2019), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-05/Signed-IL-Notice-of-Adequacy-Letter-for-2019-PHP-20-0075.pdf>.

¹³⁰ 220 ILL. COMP. STAT. ANN. 75/10 (West 2020).

¹³¹ *Id.*

expenses, contracts, and other activities” subject to regulations prescribed by the Commission, for three years.¹⁴¹ Additionally, such accounts and records must be available for inspection if requested by an authorized employee of the Commission.¹⁴² To operate as a common carrier by pipeline, the prospective individual must possess a certificate in good standing authorizing the pipeline to operate.¹⁴³ An application for such a certificate will be granted if the application was filed properly, there is a public need for the service, the applicant is willing and able to comply with all applicable acts and regulations, and public convenience and necessity requires the issuance.¹⁴⁴ Accordingly, all common carriers by pipeline must provide “adequate service to the public at reasonable rates and without discrimination.”¹⁴⁵

Additionally, the Act also provides the Commission with authority to regulate other aspects of CO₂ pipelines. Every common carrier by pipeline has an obligation to construct, maintain, and operate safety devices or structures, to revise practices affecting safety, and any other acts which may be necessary to ensure the safety of employees, customers, and the public.¹⁴⁶ Through reference to federal safety regulations, the Commission may also adopt reasonable regulations regarding the “construction, maintenance, and operations of pipelines, related facilities, and equipment to ensure the safety of pipeline employees, customers, and the public.”¹⁴⁷

Industrial Siting Requirements

Illinois is a member of the Mid-America Port Commission Agreement with both Missouri and Iowa.¹⁴⁸ Under the Agreement, there is a nine-member port commission that has the power to acquire and develop industrial sites that are necessary for the convenient use in the aid of commerce.¹⁴⁹ Additionally, the Jackson-Union Counties Regional Port District Act provides that the District shall have the power to “acquire and accept, by purchase, lease, gift, grant, or otherwise, any property and rights useful for its purpose, and to provide for the development, ownership, and construction of industrial sites, plants, and facilities, including, but not limited to, plants and facilities for ethanol and its by-products.”¹⁵⁰

¹⁴¹ See 220 ILL. COMP. STAT. ANN. 5/15-301 (West 2020).

¹⁴² *Id.*

¹⁴³ 220 ILL. COMP. STAT. ANN. 5/15-401(a) (West 2020).

¹⁴⁴ 220 ILL. COMP. STAT. ANN. 5/15-401(b) (West 2020).

¹⁴⁵ See 220 ILL. COMP. STAT. ANN. 5/15-401(h) (West 2020).

¹⁴⁶ 220 ILL. COMP. STAT. ANN. 5/15-601 (West 2020).

¹⁴⁷ *Id.*

¹⁴⁸ 45 ILL. COMP. STAT. ANN. 165/5 (West 2020).

¹⁴⁹ *Id.*

¹⁵⁰ See 70 ILL. COMP. STAT. ANN. 1820/5 (West 2020).

The District, through its Board, may also lease any of its real property, rights-of-way or privileges, or any interest therein, for industrial purposes.¹⁵¹

Storage facilities also require certain siting requirements. Under the Illinois Underground Natural Gas Storage Safety Act, an “underground natural gas storage facility” refers to a facility such as a depleted hydrocarbon reservoir, an aquifer reservoir, or a solution-mined salt cavern reservoir.¹⁵² Subject to 49 U.S.C. Section 60118(d), when a person operating an underground natural gas storage facility applies for a waiver, the ILDNR may waive in whole or in part compliance with the standards established under the Act, but only if it is determined that the waiver is consistent with the safety requirements of the facilities.¹⁵³

Any person who plans to operate an underground natural gas storage facility is required to file a plan for the inspection and maintenance of the downhole portion of the facility with the ILDNR, which ultimately has to approve the plan.¹⁵⁴ When determining the adequacy of a plan, the ILDNR shall consider: “(i) relevant available underground natural gas storage facility safety data; (ii) whether the plan is appropriate for the particular type of facility; (iii) the reasonableness of the plan; and (iv) the extent to which the plan will contribute to public safety.”¹⁵⁵ An operator must also keep records, make reports, provide information, and permit inspection of its facilities as the ILDNR requires, and shall file with the ILDNR reports of all accidents relating to the downhole portion of an underground natural gas storage facility.¹⁵⁶

Under the Act, a “violation” refers to a failure to adhere to any provision within the Act or any ILDNR order or rule that is issued under the Act.¹⁵⁷ After investigating and determining that there is a probable violation, the underground natural gas storage safety manager may then issue a notice of probable violation.¹⁵⁸ A final resolution of the probable violation is constituted by payment in full of each of the recommended penalties and full completion of each of the proposed corrective actions within thirty days of issuing the notice.¹⁵⁹

The ILDNR has jurisdiction over the downhole portion of underground natural gas storage facilities subject to this Act and the Illinois Commerce Commission retains jurisdiction over all other portions of the

¹⁵¹ *Id.*

¹⁵² See 415 ILL. COMP. STAT. ANN. 160/5 (West 2020).

¹⁵³ 415 ILL. COMP. STAT. ANN. 160/15 (West 2020).

¹⁵⁴ 415 ILL. COMP. STAT. ANN. 160/20 (West 2020).

¹⁵⁵ *Id.*

¹⁵⁶ 415 ILL. COMP. STAT. ANN. 160/25 (West 2020).

¹⁵⁷ 415 ILL. COMP. STAT. ANN. 160/35 (West 2020).

¹⁵⁸ *Id.*

¹⁵⁹ *Id.*

underground natural gas storage facilities.¹⁶⁰ However, no part of this Act is intended to limit or diminish the authority of the ILDNR under the Illinois Oil and Gas Act or the Commission under the Public Utilities Act.¹⁶¹

State Environmental Laws

Illinois has primacy for Class I-V programs, which are regulated by the Illinois Environmental Protection Agency.¹⁶² Class VI programs are regulated by the U.S. EPA and as such, interested operations must seek permission from and follow the rules of the federal government rather than the state.¹⁶³

The Illinois Administrative Code defines “Class II injection wells” as any well that injects fluids brought to the surface when using conventional methods of extracting oil and gas, is in connection with natural gas storage operations, injects fluids for enhanced oil recovery of oil or natural gas, or fluids injected for storage of hydrocarbons that are “liquid at standard temperature and pressure.”¹⁶⁴ The criteria and standards adopted by Illinois for Class II injection wells are in accordance with Section 1425 of the United States Safe Water Drinking Act.¹⁶⁵

Class II programs are administered by the Illinois Department of Natural Resources, Office of Mines and Minerals.¹⁶⁶ Currently, there are four Class I wells, zero Class III wells, and over 6,000 Class V wells operating in Illinois.¹⁶⁷ However, there are no Class IV wells in the state because they are banned by regulation.¹⁶⁸ For Class V wells within the state, an owner is not required to obtain a permit prior to beginning injection.¹⁶⁹ Rather, Class V wells are authorized by rule and must submit an Inventory Information, which identifies the type of Class V well and the nature of the injection activity, prior to beginning injection.¹⁷⁰

¹⁶⁰ 415 ILL. COMP. STAT. ANN. 160/55 (West 2020).

¹⁶¹ *Id.*

¹⁶² U.S. ENVTL PROT. AGENCY, Underground Injection Control in EPA Region 5 (IL, IN, MI, MN, OH, and WI), <https://www.epa.gov/uic/underground-injection-control-epa-region-5-il-mi-mn-oh-and-wi> (last visited Sept. 14, 2020).

¹⁶³ *Id.*

¹⁶⁴ See ILL. ADMIN. CODE tit. 35, § 704.106(b) (West 2020).

¹⁶⁵ See ILL. ADMIN. CODE tit. 35, § 730.121 (West 2020).

¹⁶⁶ ILLINOIS ENVTL PROT. AGENCY, Underground Injection Control, <https://www2.illinois.gov/epa/topics/waste-management/Pages/underground-injection-control.aspx> (last visited Sept. 14, 2020).

¹⁶⁷ *Id.*

¹⁶⁸ ILL. ADMIN. CODE tit. 35, § 704.124 (2018).

¹⁶⁹ *Id.*

¹⁷⁰ *Id.*

Local Regulation

In Illinois, state regulations do not appear to preempt local and municipal government regulation. Per the Illinois Municipal Code, the corporate authorities of each municipality have the power to grant permits to mine oil or gas with regulations that will protect both public and private property and ensure proper remuneration for any grants.¹⁷¹ Under the Oil and Gas Act, a permit will not be issued for drilling or deepening an oil or gas well within the limits of any cities, villages, or incorporated towns unless the applicant first obtains “the official consent of the municipal authorities for said well to be drilled.”¹⁷²

The Illinois Constitution, adopted in 1970, provides home rule units have the power to enact regulations for the protection of the public health, safety, morals, and welfare.¹⁷³ Municipalities, defined as cities, villages, and incorporated towns, which have populations over 25,000 are automatically home rule units.¹⁷⁴ Home rule units thus have the power to regulate activities within their area, so long as such regulations do not conflict with the Illinois Constitution or the General Assembly.¹⁷⁵

Non-home rule units only possess powers conveyed by the constitution or by statute, unless expressly authorized.¹⁷⁶ In 2012, the Appellate Court of

“The Illinois Constitution, adopted in 1970, provides home rule units have the power to enact regulations for the protection of the public health, safety, morals, and welfare.”

¹⁷¹ 65 ILL. COMP. STAT. ANN. 5/11-56-1 (West 2020).

¹⁷² 225 ILL. COMP. STAT. ANN. 725/13 (West 2020).

¹⁷³ John Abendroth, *Fracking in Illinois: Implementation of the Hydraulic Fracturing Regulatory Act and Local Government Regulatory Authority*, 35 N. ILL. U. L. REV. 575, 588 (2015).

¹⁷⁴ *Id.* at 589.

¹⁷⁵ *Id.*

¹⁷⁶ *Id.*

Illinois held that a non-home-rule city has the authority to prohibit drilling or operation of oil or gas wells within municipal limits under the Oil and Gas Act.¹⁷⁷ The court noted that while the zoning ordinances did not explicitly prohibit such activities, they were not specifically listed as “special” or “permitted uses,” and thus fell under “unlisted use” to be “deemed prohibited.”¹⁷⁸

Tribal Lands

There are no state or federally recognized tribes in Illinois.

Eminent Domain:

Chapter 735, Act 30 of the Illinois Statutes and Court rules defines the Eminent Domain Act and its powers and procedures.¹⁷⁹ In addition to other limitations and requirements, a condemning authority may not take or damage property by the power of eminent domain unless it is for a public use.¹⁸⁰ A “condemning authority” means the State, any unit of local government, school district, or other entity authorized to exercise the power of eminent domain.¹⁸¹

The state may delegate the power of eminent domain to certain entities, such as railroad or pipeline companies, as long as the public is the intended primary beneficiary.¹⁸² Property may be acquired for both private and public use, so long as it satisfies the standard of proof for “public purpose” by a preponderance of the evidence.¹⁸³

When the Illinois Commerce Commission grants a certificate of convenience or otherwise makes a finding of public convenience and necessity for an acquisition of property for private ownership for utility purposes, there exists a rebuttable presumption that such acquisition of the property is either: (i) primarily for the benefit, use, or enjoyment of the public and (ii) is necessary for a public

purpose.¹⁸⁴ In the case of acquisition of private property where no certificate of finding of public convenience and necessity is required, evidence that acquisition by eminent domain is authorized under the Public Utilities Act or Electric Supplier Act creates a rebuttable presumption that the property is either: (i) primarily for the benefit, use, or enjoyment of the public and (ii) is necessary for a public purpose.¹⁸⁵ Section 15-401 of the Public Utilities Act prescribes licensing requirements for eminent domain proceedings.¹⁸⁶ Section 13.5 of the Electrical Supplier Act prescribes the power of eminent domain proceedings.¹⁸⁷ Both are in accordance with the Eminent Domain Act.

A company may also apply to the Commission for authorization of eminent domain under Section 8-509 of the Public Utilities Act and conduct a court proceeding to acquire the lands necessary for the project.¹⁸⁸ A pipeline or common carrier company may elect to seek the Court’s assistance in the eminent domain proceeding, or do it separately and deal solely with the Commission.¹⁸⁹ If the Commission authorizes the use of eminent domain under Section 8-509 and the company is unable to reach an agreement with the landowners to acquire the property, the company can file a condemnation lawsuit in the Circuit Court where the property is located.¹⁹⁰ The Courts, not the Commission, will make the final decision as to whether the company can acquire the lands and the compensation owed under this process.¹⁹¹

Under both the Water Authorities Act¹⁹² and the Public Water District Act,¹⁹³ any power granted to acquire property by condemnation or eminent domain must be exercised in accordance with the Eminent Domain Act.¹⁹⁴ Whenever a public utility, subject to the Public Utilities Act, utilizes public property for the installation or maintenance of all or part of its water distribution system, the municipality has the right to exercise eminent domain to acquire all or part of the water system.¹⁹⁵

¹⁷⁷ See *Tri-Power Res., Inc. v. City of Carlyle*, 967 N.E.2d 811, 812 (App. Ct. 5th Dist. 2012).

¹⁷⁸ *Id.* at 815.

¹⁷⁹ See 735 ILL. COMP. STAT. ANN. 30/1-1-1 *et seq.* (West 2020).

¹⁸⁰ 735 ILL. COMP. STAT. ANN. 30/5-5-5 (West 2020).

¹⁸¹ 735 ILL. COMP. STAT. ANN. 30/1-1-5 (West 2020).

¹⁸² See *Enbridge Energy, L.L.C. v. Keurth*, 2018 IL App (4th) 150519-B, ¶ 56, 99 N.E.3d 210, 220 (In this case... the trial court was not required to examine who would be using the pipeline, the extent of any particular company’s use of the pipeline, whether those companies were part of the public or who would financially benefit from the proposed pipeline. This is because the legislature has determined that pipelines are in the public interest and that it is efficient for private companies, rather than the government, to construct and maintain these pipelines.) See also 735 ILL. COMP. STAT. ANN. 30/5-5-5(c) (citation omitted).

¹⁸³ See *Enbridge Energy, L.L.C. v. Keurth*, 2018 Ill. App (4th) 150519-B, ¶ 56, 99 N.E.3d 210, 220.

¹⁸⁴ 735 ILL. COMP. STAT. ANN. 30/5-5-5(c) (West 2020).

¹⁸⁵ *Id.*

¹⁸⁶ 735 ILL. COMP. STAT. ANN. 5/15-401 (West 2020).

¹⁸⁷ 220 ILL. COMP. STAT. ANN. 30/13.5 (West 2020).

¹⁸⁸ See 220 ILL. COMP. STAT. ANN. 5/9-509 (West 2020).

¹⁸⁹ *Id.*

¹⁹⁰ *Id.*

¹⁹¹ *Id.* See also ILL. ADMIN. CODE tit. 83, § 300 App. A (2020).

¹⁹² See 70 ILL. COMP. STAT. ANN. 3715 *et seq.* (West 2020).

¹⁹³ See 70 ILL. COMP. STAT. ANN. 3705 *et seq.* (West 2020).

¹⁹⁴ See 70 ILL. COMP. STAT. ANN. 3715/6.5 (West 2020); See 70 ILL. COMP. STAT. ANN. 3705/12.5 (West 2020); See also 735 ILL. COMP. STAT. ANN. 30 (West 2020) for the Eminent Domain Act.

¹⁹⁵ 65 ILL. COMP. STAT. ANN. 5/11-124-5 (West 2020).

Under the Gas Storage Act (“GSA”),¹⁹⁶ any corporation engaged in, or planning to engage in, the distribution, transportation, or storage of natural or manufactured gas intended for distribution in Illinois has the right to enter upon, take, or damage private property or any interest under the power of eminent domain.¹⁹⁷ This power is only for land that is necessary or convenient for the corporation’s operations, including the storage of gas, all of which operations are recognized and declared to be affecting the public interest and devoted to public use.¹⁹⁸ Before the right of condemnation may be exercised for the acquisition of property or property interest for the underground storage of gas, the corporation must apply to the Illinois Commerce Commission for an order and must receive an order approving the proposed storage project.¹⁹⁹ The condemnation power provided by the GSA must be exercised in accordance with the Eminent Domain Act.²⁰⁰

Geologic CO₂ Storage Regulation and Incremental Storage:

Illinois adopted the Carbon Dioxide Transportation and Sequestration Act (“Act”) in 2011.²⁰¹ This Act declares both carbon dioxide sequestration via pipeline transportation and enhanced oil recovery public uses and services.²⁰² The Act defines a “carbon dioxide pipeline” as the in-state portion of a pipeline, including appurtenant facilities, property rights, and easements that are used exclusively for the purpose of transporting carbon dioxide to a point of sale, storage, enhanced oil recovery, or other carbon management application.²⁰³ Any power granted pursuant to this act must be exercised in accordance with Illinois’ Eminent Domain Act.²⁰⁴

The application process is defined in Act 75, Section 20 of the Illinois Compiled Statutes.²⁰⁵ To construct, operate, or repair a CO₂ pipeline, a person or corporation must possess a certificate of authority granted by the Illinois Commerce Commission.²⁰⁶ A certificate of authority to construct and operate a CO₂ pipeline must

include the grant of authority requested and a *limited* grant of authority to acquire an easement or interest in property for the construction, maintenance, or operation of a CO₂ pipeline under the power of the Eminent Domain Act.²⁰⁷ The limited grant of authority is restricted to only the property necessary for the purpose of siting, rights-of-way, easement appurtenant, and construction and maintenance.²⁰⁸ Each CO₂ pipeline owner must construct, maintain, and operate all pipelines, facilities, and equipment in a manner that fully complies with the PHMSA, as well as any other applicable federal law, to prevent undue risk to the employees or the public.²⁰⁹

Further, Illinois enacted the Clean Coal FutureGen for Illinois Act of 2011 (“FutureGen Act”).²¹⁰ The FutureGen Act represents a first-of-a-kind research project to permanently sequester underground captured CO₂ emissions from either a coal-fueled power plant or any other approved any permitted captured CO₂ source in the State, such that the approved source would have economic benefits to the State.²¹¹ Under the FutureGen Act, “carbon capture and storage” refers to the process of collecting captured CO₂ from coal combustion by-products to inject and store the captured CO₂ for permanent storage.²¹²

Our research did not find information regarding quantification of incidentally stored carbon dioxide.

¹⁹⁶ See 220 ILL. COMP. STAT. ANN. 15 *et seq.* (West 2020).

¹⁹⁷ See 220 ILL. COMP. STAT. ANN. 15/1 (West 2020).

¹⁹⁸ *Id.*

¹⁹⁹ 220 ILL. COMP. STAT. ANN. 15/2 (West 2020).

²⁰⁰ 220 ILL. COMP. STAT. ANN. 15.5 (West 2020). See also 735 ILL. COMP. STAT. ANN. 30 (West 2020) for the Eminent Domain Act.

²⁰¹ See 220 ILL. COMP. STAT. ANN. 75/5 *et seq.* (West 2020).

²⁰² 220 ILL. COMP. STAT. ANN. 75/5 (West 2020). See 735 ILL. COMP. STAT. ANN. 30 for the Eminent Domain Act.

²⁰³ 220 ILL. COMP. STAT. ANN. 75/10 (West 2020).

²⁰⁴ 220 ILL. COMP. STAT. ANN. 75/25 (West 2020).

²⁰⁵ See 220 ILL. COMP. STAT. ANN. 75/20 (West 2020).

²⁰⁶ 220 ILL. COMP. STAT. ANN. 75/20(a)-(b) (West 2020).

²⁰⁷ 220 ILL. COMP. STAT. ANN. 75/20(i)(1)-(2) (West 2020) (emphasis added).

²⁰⁸ 220 ILL. COMP. STAT. ANN. 75/20(i)(2) (West 2020).

²⁰⁹ 220 ILL. COMP. STAT. ANN. 75/30 (West 2020).

²¹⁰ See 20 ILL. COMP. STAT. ANN. 1108/1 *et seq.* (West 2020).

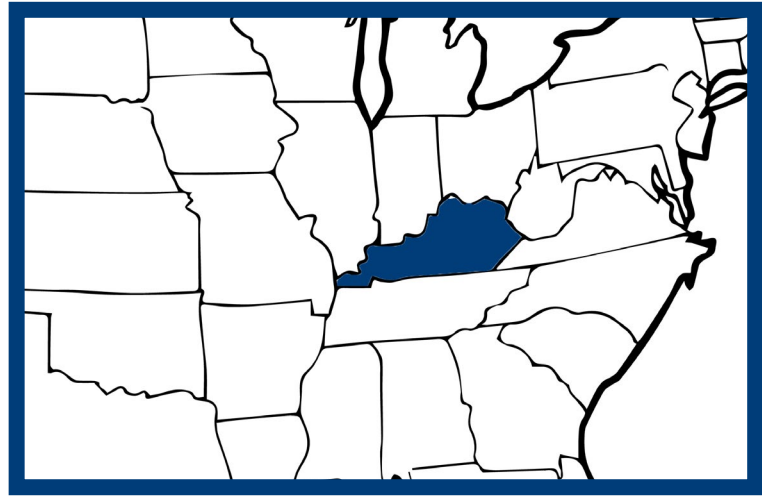
²¹¹ See 20 ILL. COMP. STAT. ANN. 1108/5 (West 2020). For the legislative findings, see 20 ILL. COMP. STAT. ANN. 1108/11 (West 2020).

²¹² 20 ILL. COMP. STAT. ANN. 1108/15 (West 2020).

KENTUCKY

Executive Summary

Kentucky has proactively enacted a statutory regime for carbon dioxide transport, utilization, and storage. Kentucky has relatively clear language for eminent domain regarding CO₂ pipelines and acquisition of pore space rights, as well as language that recognizes the potential for economic activity in the utilization or storage of CO₂. Kentucky appears to recognize three estates, the surface, mineral, and pore space, separately, with pore space natively residing with the surface estate. CO₂-EOR has been performed on a limited scale in Kentucky.



Background:

Kentucky consists of 25,428,500 acres, of which 789,300 acres (approximately 3.1%) is owned by the Federal Government. There are no tribal lands in Kentucky.

The Kentucky court system consists of district courts, circuit courts, the Kentucky Court of Appeals, and the Kentucky Supreme Court. The district courts hear matters involving violations of city and county ordinances, probate, and small claims and civil cases involving \$4,000 or less. Circuit courts hold jurisdiction over land disputes, contested probates of will, and general civil litigation in cases involving more than \$4,000, and appeals from district courts.

The Kentucky Court of Appeals is the intermediate appellate court in the state. Prior to the creation of the Kentucky Supreme Court in 1975, the Court of Appeals was the highest court. The Kentucky Supreme Court is now the court of last resort in the state and hears appeals on a discretionary basis from the Kentucky Court of Appeals, as well as mandatory reviews of death sentences, imprisonment of twenty or more years, and life imprisonment.

CO₂-EOR in Kentucky:

Efforts to enhance oil production in Kentucky date to the early 1900s and historically involved repressurization and water flood techniques. In the 1980s and 1990s, CO₂ “huff-and-puff” injection projects were deployed with notable success. In 2009, immiscible CO₂-EOR demonstration projects were initiated in western Kentucky in the Sugar Creek and Euterpe Fields. The Sugar Creek project was generally successful and injected a total of 7,230 tons of CO₂ over the course of approximately one year.¹ The Euterpe project had multiple technical

¹ FRAILEY, S., PARRIS, T., DAMICO, J., OKWEN, R., & MCKASKLE, R., CO₂ STORAGE AND ENHANCED OIL RECOVERY: SUGAR CREEK OIL FIELD TEST SITE, HOPKINS COUNTY, KENTUCKY (Univ. of Illinois, 2013).

problems and did not inject any CO₂ in the performance of that project.² A separate demonstration in Eastern Kentucky (Johnson County) was performed in 2012. This project injected CO₂, but experienced limited success due to problems with the donated well and CO₂ mobility through overlying fractures in the target formation.³ No history exists of enhanced coal bed methane (“ECBM”) in Kentucky, as there is little coal bed methane in the state.

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Ownership

In Kentucky, the expressed intention of parties to an instrument controls judicial construction.⁴ Absent specified duties and obligations, the law implies an agreement to reasonably perform what the parties could have justifiably intended in order to carry out the purpose for which the instrument was created.⁵ A court reviews an instrument concerning mineral rights in its entirety to determine whether it is a lease or a deed, but an instrument that severs estate and confers title to a certain part of the estate in another is a deed “no matter how designated.”⁶ In a deed conveying a title to property in fee simple that excepts mineral rights, Kentucky courts only consider the instrument at hand and the excepting language without reference to any prior conveyance.⁷

² UNIVERSITY OF KENTUCKY, KENTUCKY GEOLOGICAL SURVEY, *CO₂ Enhanced Oil Recovery Pilot Projects*, (2014), available at: https://www.uky.edu/KGS/education/factsheet/Factsheet_EOR2014.pdf

³ NUTTALL, B. C., *CO₂-ENHANCED GAS RECOVERY IN SHALE: LESSONS LEARNED IN THE DEVONIAN OHIO SHALE OF EASTERN KENTUCKY* at 36 (2019).

⁴ See *Gibson v. Sellars*, 252 S.W.2d 911, 913 (Ky. 1952).

⁵ See *Warfield Natural Gas Co. v. Allen*, 248 Ky. 646, 59 S.W.2d 534, 536 (1933) (citing *Humphreys v. Central Kentucky Natural Gas Company*, 190 Ky. 733, 229 S.W. 117, 119 (1920)).

⁶ See *Kentucky Nat. Gas Corp. v. Carter*, 303 Ky. 559, 561, 198 S.W.2d 311 (1946) (citing *Duncan v. Mason*, 239 Ky. 570, 39 S.W.2d 1006 (1931)).

⁷ *Gibson v. Sellars*, 252 S.W.2d 911, 913 (Ky. 1952).

Consistent with the intent of the parties, instruments conveying mineral rights imply covenants including that the lessee will develop the property in good faith and with reasonable and prudent diligence to obtain production.⁸ Absent an express timeline, an instrument granting mining rights in land is interpreted as calling for development to begin within a reasonable period.⁹ Such reasonableness is measured by what a normally prudent and diligent operator would do under the same or similar circumstances, operating in regard for the mutual benefit of both parties.¹⁰

The term “minerals” in Kentucky includes oil and gas; a conveyance of all minerals carries with it oil and gas.¹¹ Unlike some other states,¹² Kentucky adheres to the rule of capture, or the incorporeal rule of ownership, instead of the ownership theory.¹³ Once converted to personal property via extraction, natural gas remains personal property despite later storage in “underground reservoirs with confinement integrity.”¹⁴ When used in connection with minerals in place and words of inheritance, Kentucky courts read the words “grant,” “bargain,” and “sell” to vest ownership of the minerals in the grantee, absent

any contrary intent.¹⁵ When a percentage of the profits earned from the mineral rights is used as consideration, a grantor is entitled to forfeiture for nonuse or misuse of the rights.¹⁶ While abandonment of mineral rights is generally a question of fact, mineral rights are deemed abandoned as a matter of law in Kentucky when the grantee has completely failed to develop the land for thirty years.¹⁷

Court interpretations of mineral leases vary in Kentucky. Oil and gas leases are considered real estate¹⁸ whereas coal mining leases, barring any terms that require an alternate construction, are regarded as conveyances of interest in real property.¹⁹ Provided the mineral rights have not been reserved, each owner of one or more tracts covered by an oil and gas lease is entitled to the oil and gas produced on their respective tract(s) as well as royalties and rentals.²⁰ A “royalty” under an oil and gas lease is compensation for privilege or rights created by the lease and is considered “rent.”²¹ Any provision in an oil and gas lease granting a right-of-way for any purpose must be construed in connection with the lease in which the provision appears.²²

Split Estates

In Kentucky, severance of the mineral and surface estates is accomplished through either a lease of mineral rights, a deed creating a title to minerals in fee simple, or the sale of the surface with a reservation of the minerals (or vice versa).²³ An owner in fee may reserve all or only a particular class of minerals.²⁴ Once severed, each estate may be conveyed by deed, will, or as any other real property interest.²⁵ Unless the metals and minerals are excepted in the conveyance or were previously severed in ownership, an estate in fee carries with it all minerals thereunder.²⁶

⁸ Warfield Nat. Gas Co., 59 S.W.2d at 536 (citing Willis’ Thornton on Oil and Gas, § 503, 40 C. J. 1064; Flanigan v. Stern, 204 Ky. 814, 265 S.W. 324). See also Union Gas & Oil Co. v. Diles, 200 Ky. 188, 254 S.W. 205; Bay St. Petroleum Co. v. Penn Lubricating Co., 121 Ky. 637, 87 S.W. 1102; Dinsmoor v. Combs, 177 Ky. 740, 198 S.W. 58, 59.

⁹ See Eastern Kentucky Mineral & Timber Co. v. Swann-Day Lumber Co., 148 Ky. 82, 146 S.W. 438, 443 (1912) (what constitutes a “reasonable period” is largely considered a question of fact and determined on a case-by-case basis). See generally Locke v. Palmore, 308 Ky. 637, 215 S.W.2d 544 (1948); Maverick Oil & Gas Co. v. Howell, 193 Ky. 433, 237 S.W. 40 (1922); Mid-South Oil Co. v. Jaynes, 208 Ky. 483, 271 S.W. 553 (1925); Nally v. Edwards, 279 S.W.2d 251 (Ky. 1955); Swiss Oil Corp. v. Howell, 199 Ky. 763, 251 S.W. 1007 (1923); United Fuel Gas Co. v. Adams, 198 Ky. 283, 248 S.W. 841 (1923).

¹⁰ Warfield Nat. Gas Co., 59 S.W.2d at 536 (citing Willis’ Thornton on Oil & Gas, § 167).

¹¹ See Gibson v. Sellars, 252 S.W.2d 911, 913 (Ky. 1952). See generally Scott v. Laws, 185 Ky. 440, 215 S.W. 81, 13 A.L.R. 369; Ky. W. Va. Gas Co. v. Preece, 260 Ky. 601, 86 S.W.2d 163; Hurley v. West Kentucky Coal Co., 294 Ky. 96, 171 S.W.2d 15; Franklin Fluorspar Co. v. Hosick, 239 Ky. 454, 39 S.W.2d 665; Berry v. Hiawatha Oil & Gas Co., 303 Ky. 629, 198 S.W.2d 497.

¹² See generally Preston v. White, 50 S.E. 236 (W.Va. 1905); Hamilton v. Foster, 272 Pa. 95, 102 (1922); Chesapeake Exploration, L.L.C. v. Buell, 144 Ohio. St. 3d 490, 45 N.E.3d 185, 189 (2015); Murray v. Allard, 100 Tenn. 100, 43 S.W. 355, 359-60 (1897); Updike v. Smith, 378 Ill. 600, 39 N. E. 2d 325, 327 (1942).

¹³ Hammonds v. Central Kentucky Nat. Gas Co., 255 Ky. 685, 75 S.W.2d 204, 205 (1934) (under the rule of capture, oil and gas are not deemed to be owned in place like solid minerals).

¹⁴ Texas Am. Energy Corp. v. Citizens Fid. Bank & Tr. Co., 736 S.W.2d 25, 28 (Ky. 1987) (holding that the subject gas had total integrity and could neither escape nor be extracted by anyone but the plaintiff, meaning the plaintiff had “captured the wild fox, hence reducing it to personal property.”).

¹⁵ See Kentucky Nat. Gas Corp., 303 Ky. At 561 (citing Duncan v. Mason, 239 Ky. 570, 39 S.W.2d 1006 (1931)).

¹⁶ E. Kentucky Mineral & Timber Co., 146 S.W. at 443.

¹⁷ *Id.*

¹⁸ McIntire’s Adm’r v. Bond, 227 Ky. 607, 13 S.W.2d 772, 773 (1929) (citing Union Gas & Oil Co. v. Wiedeman Oil Co., 211 Ky. 361, 277 S.W. 323, 332 (1924)). See also Beckett-Iseman Oil Co. v. Backer, 165 Ky. 818, 178 S.W. 1084 (1924).

¹⁹ Johnson v. Coleman, 288 S.W.2d 348, 349 (Ky. 1956).

²⁰ Hammond v. Hammond, 292 Ky. 659, 167 S.W.2d 865, 865 (1943).

²¹ See McIntire’s Adm’r v. Bond, 13 S.W.2d at 773 (stating, “The royalty is compensation for the privilege or rights created by the lease, and, since such privileges or rights are by settled law in this state an interest in real estate, then the royalty, being a payment for such interest in real estate, is an incorporeal hereditament issuing out of the land and hence rent.”).

²² Wiser Oil Co. v. Conley, 346 S.W.2d 718, 722 (Ky. 1960).

²³ Akers v. Baldwin, 736 S.W.2d 294, 297 (Ky. 1987).

²⁴ Kincaid v. McGowan, 88 Ky. 91, 4 S.W. 802, 804 (1887).

²⁵ *Id.*

²⁶ *Id.*

Until the Kentucky Supreme Court’s decision in *Akers v. Baldwin*, broad form deeds limited mineral owners’ right to use the surface to acquire minerals only if the use was “oppressive, arbitrary, malicious, or wanton, or unless restrictions appear in deed.”²⁷ As a result of *Akers*, mineral owners must now pay damages to surface owners for any injury to the surface that occurs as the result of mineral removal unless there is an express waiver in the conveyance to the contrary.²⁸ Application of the Court’s decision in *Akers* is limited to conveyances made after the decision in 1987. The Court’s 1956 decision in *Buchanan v. Watson* controls any conveyance made prior to *Akers* as well as any future conveyance, lease, or mining efforts regarding property conveyed prior to *Akers*.²⁹ Mineral owners who made conveyances prior to *Akers* were not required to pay damages to the surface owner for injury to the surface resulting from mineral removal.³⁰

Similar to other states,³¹ the mineral estate is considered the dominant estate in Kentucky.³² When a landowner conveys all of the mineral rights with the right to search for all undiscovered minerals, the conveyance is construed as a conveyance of *all* the minerals in the land, including oil and gas.³³ While use of the surface as reasonably necessary to acquire minerals is inherent in a deed or lease of minerals,³⁴ the sole exception to a mineral owner paying damages for injury to the surface estate would be where the conveyance expressly sets out the methods of mining that may be employed and a waiver of damages for the use of such methods.³⁵ Where use of a new method of mineral acquisition, which parties at the time of conveyance did not contemplate, destroys

or substantially damages the surface owner’s remaining estates, reasonable compensation must be paid for the damage in the absence of a waiver.³⁶ A 1990 statute modified Kentucky’s common law rules for mineral use of split estates.³⁷ When the surface owner has not provided written consent to drilling operations, the statute requires the operator to provide notice to the surface owner accompanied with, *inter alia*, an offer to discuss various surface-disturbing activities.³⁸ The operator is required to reasonably compensate the surface owner “for damages to growing crops, tress, shrubs, fences, roads, structures, improvements, and livestock thereon caused by the drilling of a new well.”³⁹ Unless waived in writing, the statute requires an operator to restore the surface “to a condition as near as practicable to their condition prior to commencement of the work.”⁴⁰ The statute specifies that acceptance of statutory compensation bars a common law claim to damages.⁴¹

“A 1990 statute modified Kentucky’s common law rules for mineral use of split estates where the surface owner has no interest in the minerals by requiring notice prior to drilling, reasonable compensation for damages, and restoration of the surface at the conclusion of operations”

Pore Space Ownership

In the context of carbon sequestration, Kentucky statutorily prescribes that surface owners own the pore space “unless the pore space has been severed from the surface estate, in which case the pore space owner shall include all persons reasonably known to own an interest in the pore space.”⁴² This provision proves integral to the statutory scheme surrounding carbon storage because any person that wishes to store carbon underground must secure agreement or written consent with 51% of the surface owners before proceeding.⁴³

³⁶ *Wiser Oil Co.*, 346 S.W.2d at 721.

³⁷ KY. REV. STAT. ANN. §353.595 (West 2020).

³⁸ KY. REV. STAT. ANN. § 353.595(3)(c) (West 2020); *see also* §353.595(4) (providing a list of surface disturbing activities to be discussed).

³⁹ KY. REV. STAT. ANN. §§ 353.595(5)-(6) (West 2020).

⁴⁰ KY. REV. STAT. ANN. § 353.595(7) (West 2020).

⁴¹ KY. REV. STAT. ANN. § 353.595(8) (WEST 2020).

⁴² *See* KY. REV. STAT. ANN. § 353.800(8) (West 2020) (“Pore space” specifically refers to the voids in subsurface reservoir strata suitable to contain stored carbon dioxide.).

⁴³ KY. REV. STAT. ANN. § 353.806 (West 2020).

²⁷ *Id.* (citing *Buchanan v. Watson*, 290 S.W.2d 40 (Ky. 1956)).

²⁸ *Id.* at 306 (holding the measurement of damages to the surface estates under a broad form deed as the difference in market value of the surface estate, including all improvements, immediately before and after use of the surface by the mineral owner).

²⁹ *Id.* at 307. *See Buchanan v. Watson*, 290 S.W.2d 40 (Ky. 1956) (holding a grantee could destroy the surface through strip mining and not be held liable for damages to surface owner for destruction of such surface rights, in absence of arbitrary, wanton, or malicious destruction).

³⁰ *See Akers v. Baldwin*, 736 S.W.2d 294, 298 (Ky. 1987) (A “broad form deed” severs the mineral estate from the surface estate, and typically conveys to the grantee all minerals beneath the surface as well as the right to “full and free exercise and enjoyment of the minerals” as the grantee deems necessary.).

³¹ *See generally* Squires v. Lafferty, 95 W. Va. 307, 212 S.E. 90 (1924); *Belden & Blake Corp. v. DCNR*, 600 Pa. 559, 969 A.2d 528, 532 (2009); Ronald W. Polston, *Surface Rights of Mineral Owners—What Happens When Judges Make Law and Nobody Listens?*, 63 N.D. L. REV. 41, 42-43 (1987); *Pearne v. Coal Creek Min. & Mfg. Co.*, 90 Tenn. 619, 18 S.W. 402, 404 (1891).

³² *Akers*, 736 S.W.2d at 297.

³³ *Scott v. Laws*, 185 Ky. 440, 215 S.W. 81, 82 (1919) (emphasis added).

³⁴ *Wiser Oil Co. v. Conley*, 346 S.W.2d 718, 721 (Kent. App. 1960).

³⁵ *Akers*, 736 S.W.2d at 305-06.

Regarding gas storage, Kentucky courts historically held that gas re-injected into storage wells was subject to the rule of capture and was essentially a “wild” resource.⁴⁴ Kentucky also affirmatively recognizes “that because the mineral owner possessed rights to stored minerals (as injected gas was subject to the rule of capture), the mineral owner was entitled to lease gas storage rights.”⁴⁵ The Supreme Court of Kentucky has since seemingly relaxed the rule of capture, as evidenced by holding that “previously extracted oil and gas subsequently stored in underground reservoirs . . . do[es] not become subject to the rights of owners of surface above the storage fields.”⁴⁶ This holding fails to directly contemplate “pore space” but implies a shift in the foundation of the Court’s previous holdings. Neither the courts nor the legislature address pore space in the context of produced water or chemical well injection.

Water Rights

Riparian rights govern the use of surface water in Kentucky.⁴⁷ A downstream owner is entitled to the natural flow of the water, except as diminished by the reasonable use of upstream owners.⁴⁸ Kentucky uses the reasonable use rule, or “American Rule,” for percolating groundwater.⁴⁹ A landowner may use groundwater “for all purposes properly connected with the use, enjoyment, and development of the land itself.”⁵⁰ Liability attaches where the use of the water is negligent.⁵¹ The loss of a water well due to blasting was actionable without a showing of negligence.⁵² Relating to oil and gas, where a spring was severely damaged during the laying of a pipeline, the diminution in the market value of the spring was the correct measure of damages.⁵³

⁴⁴ See generally *Hammonds v. Cent. Ky. Nat. Gas Co.*, 75 S.W.2d 204, 205-06 (Ky. 1934), *overruled by* *Texas Am. Energy Corp. v. Citizens Fid. Bank & Tr. Co.*, 736 S.W.2d 25 (Ky. 1987) (The “rule of capture” refers to the general rule that the first person to “capture” a natural resource, such as oil and gas, owns that resource.)

⁴⁵ See Stefanie L. Burt, *Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions*, 4 *Joule: DUQ. ENERGY & ENVTL. L.J.* 1 (2016) (citing *Cent. Ky. Nat. Gas Co. v. Smallwood*, 252 S.W.2d 866, 869 (Ky. Ct. App. 1952)).

⁴⁶ See *Tex. Am. Energy Corp. v. Citizens Fidelity Bank & Tr.*, 736 S.W.2d at 28.

⁴⁷ *Kraver v. Smith*, 164 Ky. 674, 683-84 (1915) (A “riparian owner” is one owning land which is bounded by a natural water course or through which a stream flows.).

⁴⁸ *Id.*

⁴⁹ See *United Fuel Gas Co. v. Sawyers*, 259 S.W.2d 466, 468 (Ky. 1953).

⁵⁰ *Id.* at 467-68. See also *Associated Contractors Stone Co. v. Pewee Val. Sanitarium & Hosp.*, 376 S.W.2d 316 (Ky. 1963).

⁵¹ See *Associated Contractors Stone Co. v. Pewee Valley Sanitarium and Hosp.*, 376 S.W.2d 316, 318 (1963), reh’g denied (1964).

⁵² *Wolf Creek Collieries Co. v. Davis*, 441 S.W.2d 401, 403 (Ky. 1969), reh’g denied (1969).

⁵³ *Texas Gas Transmission Corp. v. Kinslow*, 461 S.W.2d 69, 72 (Ky. 1970).

Kentucky is a “regulated riparian” state, having passed statutory provisions that supplement the common law of water rights in 1966. Anyone wishing to “withdraw, divert, or transfer” “public water” must apply for a permit.⁵⁴ “Public water” includes virtually all water in the state, including surface water and groundwater.⁵⁵ However, where withdrawals are made at a relatively constant rate and the average withdrawal rate is 10,000 gallons per day or less, no permit is required.⁵⁶ In addition, the statute exempts water for domestic and agricultural purposes from the permitting scheme.⁵⁷ No permit is required for water used in the production of steam generating plants for certain companies and, notably, water injected underground in conjunction with operations for the production of oil or gas.⁵⁸

Lithium Ownership and Extraction

Kentucky’s legal and regulatory framework does not specifically contemplate lithium extraction or mining.

Classification of CO₂: Commodity and Pollutant

Kentucky’s current legal view of CO₂ is multifaceted. On one hand, Kentucky statutorily recognizes the need to reduce CO₂ emissions,⁵⁹ which would indicate it is classified as a pollutant.

On the other hand, Kentucky’s legislature indicates that CO₂ may be an element of economic activity. For example, Kentucky enabled permitted companies to condemn the necessary property for the construction of a “carbon dioxide transmission pipeline.”⁶⁰ Another statute lays out specific regulations for CO₂ storage, and the law states it was passed for both “environmental” and “economic” reasons.⁶¹ Although we did not find any indications of natural CO₂ production in Kentucky, CO₂ “contained in or on the soils” may fall within the definition of “natural resource” for purposes of Kentucky’s Natural Resources Severance and Processing Taxes.⁶² This definition would exclude anthropogenically captured CO₂. Kentucky also provides a number of tax incentives related to carbon capture, including a severance tax credit.⁶³

⁵⁴ See KY. REV. STAT. ANN. § 151.150(1) (West 2020).

⁵⁵ KY. REV. STAT. ANN. § 151.120 (West 2020).

⁵⁶ 410 KY. ADMIN. REGS. 4:010.1(2).

⁵⁷ KY. REV. STAT. ANN. § 151.140 (West 2020).

⁵⁸ *Id.*

⁵⁹ KY. REV. STAT. ANN. § 224.20-100 (West 2020).

⁶⁰ KY. REV. STAT. ANN. § 154.27-100 (West 2020).

⁶¹ KY. REV. STAT. ANN. § 353.802 (West 2020); KY. REV. STAT. ANN. § 353.800 (West 2020).

⁶² KY. REV. STAT. ANN. § 143A.010(2) (West 2020).

⁶³ UNITED STATES ENERGY ASSOCIATION, Peter Connors, et. al., *Review of Federal State, and Regional Tax Strategies and Opportunities for CO₂-EOR-Storage and the CCUS Value Chain* (September 21, 2020).

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

Chapter 353, Sections 500 to 720 of the Kentucky Revised Statutes contain Kentucky's oil and gas conservation laws.⁶⁴ The responsibility to administer these laws belongs to the Director of the Division of Oil and Gas.⁶⁵ The Kentucky Oil and Gas Conservation Commission ("KOGCC") evaluates and issues orders on all applications in the state for the establishment of drilling units and pooling.⁶⁶ The KOGCC administers regulations and issues orders⁶⁷ pursuant to the procedures of Chapter 13 of the Kentucky Revised Statutes.⁶⁸ The operator of a unitized tract must have the consent of at least 51% of the interest in the proposed unitized tract before approval of a forced pooling application.⁶⁹

Similar forced pooling laws exist for carbon dioxide storage wells.⁷⁰ After good faith negotiations between storage operators and owners of pore space fail to reach a voluntary pooling agreement, the storage operator can apply to the Division of Oil and Gas for a forced pooling order, provided the storage operator has the consent of at least 51% of the owners of the pore space.⁷¹

Kentucky adheres to a non-ownership theory of oil and gas in their natural state, as well as to the rule of capture, with the Kentucky Court of Appeals stating "oil and gas are not the property of anyone until reduced to actual possession."⁷² The oil or gas only becomes exclusive property when it is drawn out of the ground by the owner.⁷³ Fractures in the subsurface caused by hydraulic fracturing operations are not considered a physical trespass, but rather are viewed by courts as natural in relation to the rule of capture.⁷⁴ Spacing laws

⁶⁴ See KY. REV. STAT. ANN. §§ 353.500 – 353.720 (West 2020).

⁶⁵ KY. REV. STAT. ANN. § 353.530(2) (West 2020).

⁶⁶ KY. REV. STAT. ANN. § 353.565 (5) (West 2020).

⁶⁷ KY. REV. STAT. ANN. §§ 353.561(1)(a) & 353.652(1) (West 2020).

⁶⁸ KY. REV. STAT. ANN. §§ 13B.005 – 13B.150 (West 2020).

⁶⁹ KY. REV. STAT. ANN. § 353.630 (West 2020).

⁷⁰ KY. REV. STAT. ANN. §§ 353.806 – 353.808 (West 2020).

⁷¹ KY. REV. STAT. ANN. § 353.806(1)-(2) (West 2020).

⁷² See *Hammonds v. Central Ky. Nat. Gas Co.*, 255 Ky. 685 (Ky. Ct. App. 1934) (as quoted in Bryan R. Reynolds, *Kentucky Oil and Gas Conservation Laws: Keeping Pace with Technological Advances in the Oil and Gas Industry*, 9 KY. J. EQUINE, AGRIC. & NAT. RES. L. REV. 387, 389 (2017)).

⁷³ *Hail v. Reed*, 54 Ky. 479, 491 (Ky. Ct. App. 1854).

⁷⁴ *Coastal Oil & Gas v. Garza Energy Tr.*, 268 S.W. 1, 7 (Tex. 2008) ("Clues about the direction in which fractures are likely to run horizontally from that well may be derived from seismic and other data, but virtually nothing can be done to control that direction; the

perhaps provide a basis for a trespass action when oil drains to a well that is too close to another well or property boundary,⁷⁵ but the KOGCC can modify spacing orders by reducing the distance between wells or between a well and property boundaries.⁷⁶ Unless "clearly unreasonable or unjust," a court will likely uphold the order.⁷⁷

The majority of Kentucky case law focuses on the question of damages to be afforded for a trespass. An innocent trespasser will only be required to pay damages equal to the "value of the minerals after extraction, less the mining operation expenses that were reasonably calculated to be beneficial and productive in producing the minerals."⁷⁸ A willful trespasser must pay "the fair market value of the minerals without any allowance for expenses."⁷⁹ This applies to all mineral extraction, including natural gas.⁸⁰

Induced seismicity is not found anywhere in the Kentucky statutes or regulations regarding injection wells or oil and gas wells in general. Licensing requirements⁸¹ and requirements for seismic data record keeping⁸² reside within Title 805, Chapter 4 of the Kentucky Administrative Regulations. Quantification of incidental storage seemingly appears nowhere in the oil and gas statutes and regulations in Kentucky.

State Environmental Laws

The Kentucky Department of Natural Resources ("KYDNR") administers the state's UIC program,⁸³ and regulations for Kentucky's UIC program are found in Title

fractures will follow Mother Nature's fault line in the formation. The vertical dimension of the fracturing pattern is confined by barriers—in this case, shale—or other lithological changes above and below the reservoir") (as quoted in Bryan R. Reynolds, *Kentucky Oil and Gas Conservation Laws: Keeping Pace with Technological Advances in the Oil and Gas Industry*, 9 KY. J. EQUINE, AGRIC. & NAT. RES. L. REV. 387, 424 (2017)).

⁷⁵ *R.R. Comm'n of Texas v. Bass*, 10 S.W. 2d 586 (Tex. App. 1928)

(as quoted in Bryan R. Reynolds, *Kentucky Oil and Gas Conservation Laws: Keeping Pace with Technological Advances in the Oil and Gas Industry*, 9 KY. J. EQUINE, AGRIC. & NAT. RES. L. REV. 387, 413 (2017)).

⁷⁶ KY. REV. STAT. ANN. § 353.620(2) (West 2020) (as quoted in Bryan R. Reynolds, *Kentucky Oil and Gas Conservation Laws: Keeping Pace with Technological Advances in the Oil and Gas Industry*, 9 KY. J. EQUINE, AGRIC. & NAT. RES. L. REV. 387, 411 (2017)).

⁷⁷ *R.R. Comm'n*, 10 S.W.2d at 588 ("The commission is an administrative body, and its orders and rulings must be upheld unless they are clearly shown to be unreasonable or unjust").

⁷⁸ See *Harrod Concrete & Stone Co. v. Crutcher*, 458 S.W.3d 290, 299-300 (Ky. 2015).

⁷⁹ *Id.* at 300.

⁸⁰ *Id.* at 295.

⁸¹ 805 KY. ADMIN. REGS. 4:010 (2020).

⁸² 805 KY. ADMIN. REGS. 4:030 & 4:050 (2020).

⁸³ KY. REV. STAT. ANN. § 353.590 (2)(b) (West 2020).

805, Chapter 1, Section 110 of the Kentucky administrative regulations.⁸⁴ Kentucky obtained primacy for the Class II UIC program under Section 1425 of the SDWA on March 21, 2017. Statutory authority for the Division of Oil and Gas to administer the UIC Class II program is provided in Chapter 353 of the Kentucky Revised Statute.⁸⁵ However, the Commonwealth's authority does not include the regulation of injection well Classes I, III, IV, V, and VI and all wells on Indian lands. An approved Class II well is conditioned upon compliance with state UIC regulations regarding inspection, monitoring, and verification.⁸⁶

The KYDNR administers the state's UIC program to comply with the "regulations promulgated by the Environmental Protection Agency pursuant to the Underground Injection Control Program of the Safe Drinking Water Act, U.S.C. § 300(f) et seq."⁸⁷ The criteria for an aquifer exemption resides in Section 805 of Kentucky Administrative Regulations.⁸⁸ An aquifer may not be exempted if it currently serves or may serve in the future as a source of drinking water.⁸⁹

Pipeline Regulation

In Kentucky, the state inspects and enforces the pipeline safety regulations for intrastate gas pipeline operators, through certification by OPS. This work is performed by the Kentucky Public Service Commission.⁹⁰ By letter dated December 31, 2019, OPS notified the state that its enforcement of Kentucky's excavation damage prevention law was "adequate."⁹¹

In Kentucky, the transportation and delivery of natural gas into, through, and from a pipeline operated by any company transporting or delivering natural gas for public consumption, making it a common carrier, is declared to be a public use.⁹² Under Kentucky law, a "carbon dioxide transmission pipeline" refers to the in-

⁸⁴ 805 KY. ADMIN. REGS. 1:110 (2020).

⁸⁵ KY. REV. STAT. ANN. §§ 353.590(2) & 353.591-353.592 (West 2011). See also, Underground Injection Control Wells, KY. ENERGY AND ENVT. CABINET, <https://eec.ky.gov/Natural-Resources/Oil-and-Gas/Programs/Pages/underground-injection-control-wells.aspx> (last visited Sept. 14, 2020).

⁸⁶ *Id.* at § 4 (1)-(5). See also KY. REV. STAT. ANN. § 353.592 (West 2020).

⁸⁷ *Id.*

⁸⁸ 805 KY. ADMIN. REGS. 1:110 §3(2) (2020).

⁸⁹ *Id.*

⁹⁰ U.S. DEP'T OF TRANSP., PIPELINE & HAZARDOUS MATERIALS SAFETY ADMIN., REGULATORY FACT SHEET: KY., https://primis.phmsa.dot.gov/comm/FactSheets/States/KY_State_PL_Safety_Regulatory_Fact_Sheet.htm.

⁹¹ Letter from Massoud Tahamtani, Deputy Associate Director, Policy and Programs, Office of Pipeline Safety, to Michael J. Schmitt, Chairman, Ky. Pub. Serv. Comm'n (Dec. 31, 2019), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-05/Signed-KY-Notice-of-Adequacy-Letter-for-2019-PHP-20-0090.pdf>.

⁹² KY. REV. STAT. ANN. § 278.470 (West).

state portion of a pipeline that is used exclusively for the purpose of transporting carbon dioxide to a point of sale, storage, or other carbon management applications.⁹³

Industrial Siting Requirements

Under the Local Industrial Development Authority Act, the acquisition of any property with the purpose of developing industrial sites is a public and governmental function, exercised for a public purpose, and a matter of public necessity.⁹⁴ When developing industrial sites, the legislative body of any government unit may make an annual appropriation, on its credit, from its general fund, to provide money for the purchase of property.⁹⁵ The authority may defray the costs of acquiring the property through the issuance of revenue bonds.⁹⁶ Alternatively, the authority may also acquire and develop land for industrial use and issue revenue bonds.⁹⁷ If the authority determines that the bonds already authorized will be insufficient, additional bonds may similarly be issued. However, a city may not issue additional revenue bonds with the purpose of purchasing a tract of land to be used as an industrial site unless the city constructs a factory building that will produce sufficient rental to pay the interest and principal on the bonds.⁹⁸ Any property that is acquired by the authority for the development of industrial sites is exempt from taxation, similar to other property which is used for public purposes.⁹⁹

Local Regulation

Under Section 353.500 of the Oil and Gas Conservation Act, the state government bears the responsibility for regulation of oil and gas exploration, production, development, gathering, and transmissions.¹⁰⁰ However, in *Blancett v. Montgomery*, the Court of Appeals of Kentucky held that Section 353.500 must be read "in conjunction with and subordinate to the basic powers possessed by municipalities."¹⁰¹ The Court reasoned that municipalities retain their police power right to regulate oil and gas activities, such as through zoning ordinances, within their city limits.¹⁰²

In 2017, the Kentucky Office of the Attorney General affirmed the holding and reasoning in *Blancett*.¹⁰³

⁹³ KY. REV. STAT. ANN. § 278.495 (West).

⁹⁴ KY. REV. STAT. ANN. § 154.50-346 (West 2020).

⁹⁵ KY. REV. STAT. ANN. § 154.50-340 (West 2020).

⁹⁶ *Id.*

⁹⁷ *Id.*

⁹⁸ See 1959 OAG 43,999; KY. REV. STAT. ANN. § 103.280 (West 2020).

⁹⁹ KY. REV. STAT. ANN. § 154.50-343 (West 2020).

¹⁰⁰ KY. REV. STAT. ANN. § 353.500(2) (West 2020).

¹⁰¹ See *Blancett v. Montgomery*, 398 S.W.2d 877, 881 (Ky. 1966) (emphasis added).

¹⁰² *Id.*

¹⁰³ Ky. Op. Att'y Gen. No. 17-003, 2017 WL 933435 (Mar. 3, 2017).

There, the Attorney General opined that the Letcher County Fiscal Court had the authority to impose a license tax on oil and gas companies within the county, dismissing the argument that section 353.500 would be violated.¹⁰⁴ While the courts of Kentucky are not bound by Attorney General Opinions, such opinions are considered highly persuasive and are given great weight.¹⁰⁵

Tribal Land

Our research did not reveal the presence of any tribal land in Kentucky.

Eminent Domain:

The Eminent Domain Act of Kentucky is prescribed under Sections 416.540 to 416.680 of the Revised Code.¹⁰⁶ The right of eminent domain means the right of the Commonwealth to take for public use and includes the right of private persons, corporations, or business entities to do so under the authority of law.¹⁰⁷ Public use includes the use of property for the creation or operation of public utilities or common carriers.¹⁰⁸

Any corporation engaged in, or planning to engage in, constructing, maintaining, or operating oil or gas wells or pipelines for transporting or delivering oil or gas may condemn property necessary for those purposes.¹⁰⁹ The purposes include constructing, maintaining, drilling, utilizing, and operating pipelines, underground oil, or gas storage fields.¹¹⁰ In addition, the condemnation authority extends to the necessary rights of ingress and egress to construct, examine, alter, repair, maintain, operate, or remove such pipelines or underground gas storage fields.¹¹¹ So long as the easement provides reasonable access to the pipeline, ingress and egress is limited to the easement itself.¹¹² The limitation of ingress and egress for a pipeline is defined under Kentucky Revised Code Section 416.330.

A corporation, partnership, or individual seeking to condemn lands under the provisions of Section 278.502 may file a verified petition with the Circuit Court clerk of the county in which all, or the greater portion of the land, is located.¹¹³ Condemnation proceedings are conducted in accordance with the Eminent Domain Act of Kentucky.

¹⁰⁴ *Id.*

¹⁰⁵ Bentley v. Commonwealth, 497 S.W.3d 253, 255 (Ky. Ct. App. 2016) (emphasis added).

¹⁰⁶ See KY. REV. STAT. ANN. § 416.540 et seq. (West 2020).

¹⁰⁷ KY. REV. STAT. ANN. § 416.540(5) (West 2020).

¹⁰⁸ KY. REV. STAT. ANN. § 416.675(2)(d) (West 2020).

¹⁰⁹ See generally KY. REV. STAT. ANN. § 278.502 (West 2020).

¹¹⁰ *Id.*

¹¹¹ *Id.*

¹¹² KY. REV. STAT. ANN. § 416.330 (West 2020).

¹¹³ KY. REV. STAT. ANN. § 416.230 (West 2020).

Any water district or municipality has the right to acquire all lands, easements, rights-of-way, either above or below ground, necessary or desirable in connection with the construction, operation, or maintenance of water plants or water distribution systems.¹¹⁴ Further, any water association supplying water to no less than 100 customers may exercise the power of eminent domain.¹¹⁵ Any person or company constructing, maintaining, or operating waterworks or pipelines for the supply of water to a municipality may condemn lands necessary to carry out those purposes.¹¹⁶

The Kentucky legislature seems to address subsurface rights only tangentially. Section 65.478 of the Revised Code, states that an easement cannot be transferred unless there is written consent of the owner of such subsurface rights (given the estates have been split).¹¹⁷

Kentucky Revised Statute Section 154.27-100 sets the standards for when a CO₂ pipeline company may use eminent domain.¹¹⁸ If a CO₂ transmission pipeline company has received a construction certificate from the Kentucky State Board on Electric Generation and Siting, and the company is unable to contract or agree with the owner after a good-faith effort to do so, the company may condemn the lands that are necessary for:

- (a) Constructing, maintaining, utilizing, operating, and gaining access to a carbon dioxide transmission pipeline and all necessary machinery, equipment, pumping stations, appliances, and fixtures for use in connection with a carbon dioxide transmission pipeline; and
- (b) Obtaining all necessary rights of ingress and egress to construct, examine, alter, repair, maintain, operate, or remove a carbon dioxide transmission pipeline and all of its component parts.¹¹⁹

The proceedings for condemnation are as provided in the Eminent Domain Act of Kentucky.¹²⁰ Carbon dioxide transmission pipelines and the routing, construction, maintenance, and operation of them are, as a matter of legislative determination, declared to be a public use essential to the fulfillment of the purposes of this chapter.¹²¹

¹¹⁴ KY. REV. STAT. ANN. § 106.220 (West 2020).

¹¹⁵ KY. REV. STAT. ANN. § 416.340 (West 2020).

¹¹⁶ KY. REV. STAT. ANN. § 96.080 (West 2020).

¹¹⁷ See KY. REV. STAT. ANN. § 65.478 (West 2020).

¹¹⁸ See KY. REV. STAT. ANN. § 154.27-100 (West 2020).

¹¹⁹ See KY. REV. STAT. ANN. § 154.27-100(2)(a)-(b) (West 2020).

¹²⁰ See KY. REV. STAT. ANN. § 416.540 et seq. (West 2020).

¹²¹ KY. REV. STAT. ANN. § 154.27-100(4) (West 2020).

CO₂ Storage Regulation for EOR and Incremental Storage:

Kentucky's regulations for geologic storage of CO₂ are prescribed under Sections 353.800-812 of the Revised Code. The Energy and Environment Cabinet (Cabinet) of Kentucky aims for one to five demonstration pilot-projects that incorporate carbon storage or projects that integrate carbon capture and storage.¹²² Further, Kentucky aims to initiate discussions and reciprocal agreements with surrounding states to develop a coordinated and unified approach to subsurface migration of stored CO₂.¹²³

An approved project injects CO₂ into pore space that contains no economically recoverable minerals at the time and must either: incorporate carbon storage or integrate carbon capture and storage technology or be a carbon capture and storage project that is associated with a project that has been otherwise qualified and been approved for incentives under the Incentives for Energy Independence Act.¹²⁴ An applicable section of the Incentives for Energy Independence Act includes Kentucky Revised Statute Section 154.27-100, discussed above.

An applicant must file the necessary application for a Class V well with Region 4, U.S. EPA.¹²⁵ The applicant must begin work on the project within 18 months of the date the Class V well permit is granted, but the applicant may request an extension of time if needed.¹²⁶ If the requirements of this subsection are not met, the approval may be revoked.¹²⁷

The storage operator must negotiate with the pore space owners and acquire the rights needed to access the pore space.¹²⁸ If, after good-faith negotiation, the storage operator cannot locate or cannot reach an agreement with all necessary pore space owners, but has secured written consent or agreement from the owners of at least 51% of the interest in the pore space for the storage facility, the division must order the pooling of all pore space included within the proposed facility if the requirements of this section and Section 353.808 of the Revised Code have

been met.¹²⁹ Unknown or non-locatable owners are deemed to have consented or agreed to the pooling, provided that the requirements of Section 353.808 are met.¹³⁰ A carbon injection well is exempt from the provisions of Sections 353.651-652 of the Revised Code, regardless of the depth of the well.¹³¹

The ownership and liability for a storage facility may be transferred to either a federal government, if a federal program exists, or the Finance and Administration Cabinet pursuant to subsections (4), (5), and (6) of this subsection if a federal program does not exist.¹³² Ownership of and liability for the stored carbon dioxide remains with the storage operator until the transfer is completed.¹³³

Chapter 353, Sections 800 to 812 of the Kentucky Revised Statutes Annotated address geological storage of CO₂.¹³⁴ The Division of Oil and Gas holds “primary jurisdiction and authority over matters relating to the geologic storage in the Commonwealth once these programs have been developed at the federal level.”¹³⁵ Ownership and liability remain with the storage operator after the operator has filled and plugged carbon injection well,¹³⁶ but the operator has the option to transfer ownership and liability to the federal government if such a program exists or if the operator meets certain statutory requirements, the Kentucky Finance and Administration Cabinet.¹³⁷

“Kentucky aims to initiate discussions and reciprocal agreements with surrounding states to develop a coordinated and unified approach to subsurface migration of stored CO₂.”

¹²² See KY. REV. STAT. ANN. § 353.802(5) (West 2020) & KY. REV. STAT. ANN. § 353.804(2) (West 2020).

¹²³ See KY. REV. STAT. ANN. § 353.812 (West 2020).

¹²⁴ See KY. REV. STAT. ANN. § 353.804(2) (West 2020).

¹²⁵ See KY. REV. STAT. ANN. § 353.804(3) (West 2020).

¹²⁶ *Id.*

¹²⁷ *Id.*

¹²⁸ See KY. REV. STAT. ANN. § 353.806(1) (West 2020).

¹²⁹ KY. REV. STAT. ANN. § 353.806(2) (West 2020).

¹³⁰ KY. REV. STAT. ANN. § 353.806(2) (West 2020).

¹³¹ KY. REV. STAT. ANN. § 353.806(3) (West 2020). See KY. REV. STAT. ANN. § 353.651 (Vertical and horizontal deep wells; establishment and regulation of drilling units; pooling of interests; exceptions); See KY. REV. STAT. ANN. § 353.652 (Unit operation of pool; procedure).

¹³² KY. REV. STAT. ANN. § 353.810(3) (West 2020).

¹³³ KY. REV. STAT. ANN. § 353.810(5) (West 2020).

¹³⁴ KY. REV. STAT. ANN. §§ 353.800- 353.812 (2020).

¹³⁵ KY. REV. STAT. ANN. § 353.804(1) (West 2020).

¹³⁶ KY. REV. STAT. ANN. § 353.810(2) (West 2020).

¹³⁷ *Id.* at (3)-(6) (West 2011).

MONTANA

Executive Summary

Montana laws address many aspects of CO₂-EOR while contingency provisions are in place to regulate CO₂ geologic storage if and when Montana is granted primacy over Class VI wells. While Montana law allows mineral operators to reasonably use pore space for activities related to oil and gas production, the legislature and courts have not precluded either statutory liability or liability for potential common law torts. Montana provides eminent domain authority for underground storage reservoirs, natural gas public utilities and common carrier pipelines, but it is unclear whether this power extends to permit condemnation of pore space for purposes of geologic CO₂ storage.

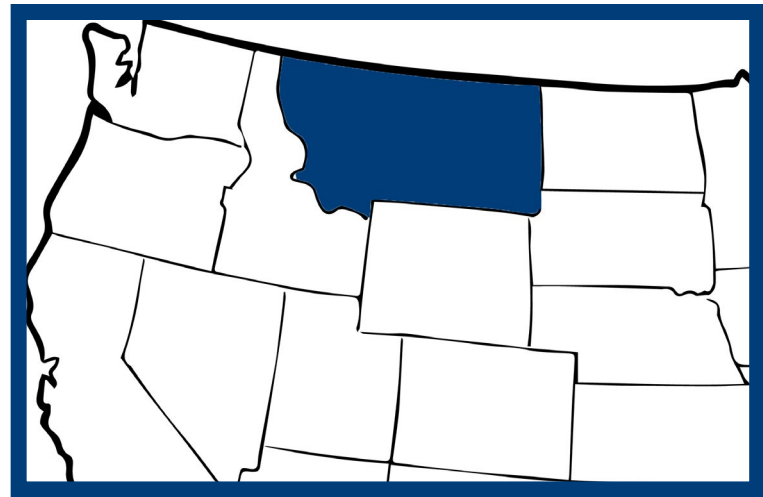
Background:

Montana includes federal, state, fee, and tribal land. Of its 94,109,440 acres of land, 27,378,247 acres (29%) is federally owned. Federal land ownership in Montana is dispersed across the state, but the western portion of the state has a larger concentration. There are an additional 11 million acres of federal split estate lands, with private surface ownership and federal mineral ownership.¹

Montana operates under a common law legal system. The state's 56 district courts, which are structured into 22 judicial districts, serve as courts of general jurisdiction and have limited appellate jurisdiction over cases from courts of limited jurisdiction in their district. Montana does not have a state appellate court. All appeals of district court decisions go directly to the Montana Supreme Court. Additionally, Montana is one of only a handful of states to have a separate water court system. Montana's water court system was created in 1979 and has exclusive jurisdiction over the adjudication of water rights claims.

State regulatory authority over oil and gas and pipeline operations are shared between the Montana Board of Oil and Gas Conservation and the Montana Department of Environmental Quality. Local governments have minimal regulatory authority over oil and gas operations, although property owners may use "planning and zoning districts" to exercise some regulatory authority.

¹ Joel Schumacher & Tim Fitzgerald, *Be A Savvy Landowner: Understanding Mineral Rights*, BIG SKY SMALL ACRE, FALL 12 (2015).



CO₂-EOR in Montana:

The Bell Creek Oil Field in the southeastern portion of the state is the most notable CO₂-EOR project in Montana. Denbury Onshore, L.L.C. plans to inject approximately one million tons of CO₂ per year into the Bell Creek Oil Field.² CO₂-EOR operations began in May 2013³ and are expected to produce an additional 40-50 million barrels of oil as well as the incidental storage of millions of tons of anthropogenic CO₂.⁴ CO₂ used in the Bell Creek Field is transported via the Greencore Pipeline from the Lost Cabin and Shute Creek gas plants in Wyoming.⁵ Denbury Resources Inc. also operates an extensive oil and gas project at Cedar Creek Anticline with significant CO₂-EOR potential.⁶ Current plans call for a 105-mile extension of the Greencore Pipeline during 2020 to enable future CO₂-EOR.⁷

² CO₂ Sequestration Projects, The Bell Creek Integrated EOR and CO₂ Storage Project, ENERGY & ENVTL RESEARCH CTR., <https://undeerc.org/pcor/co2sequestrationprojects/BellCreek.aspx> (last visited June 23, 2020)

³ NAT'L ENERGY TECH. LABORATORY, BELL CREEK FIELD PROJECT, <https://www.netl.doe.gov/sites/default/files/2018-11/Bell-Creek-Project.pdf> (last visited July 2, 2020).

⁴ *Id.*

⁵ Melanie D. Jensen et al., *Bell Creek Test Site – Transportation and Injection Operations Report*, PLAINS CO₂ REDUCTION PARTNERSHIP, ENERGY & ENVTL RESEARCH CTR. (2015), <https://undeerc.org/PCOR/technicalpublications/pdf/TR-2015-Bell-Creek-Test-Site-Transportation-and-Injection-Operations-Report.pdf>.

⁶ DENBURY, FUTURE TERTIARY OPERATIONS, <https://www.denbury.com/operations/rocky-mountain-region/tertiary-operations/default.aspx> (last visited July 2, 2020).

⁷ *Id.*

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

Montana courts interpret mineral deeds according to Montana’s statutory rules of contract interpretation.⁸ Courts must interpret contracts to give effect to the intent of the parties.⁹ Courts first look to the language of a contract to find evidence of intent.¹⁰ If the contract, or deed, is unclear, courts may reference extrinsic evidence, or the “circumstances under which [the contract] was made and the matter to which it relates,” in order to ascertain the parties’ intent.¹¹

When a deed conveys an interest in minerals, Montana courts have found that the term “mineral” does not always have a clear meaning.¹² Montana courts use “contextual clues” to interpret a mineral grant or reservation, with the “overarching goal of effectuating the parties’ intent.”¹³ To do so, Montana courts consider whether the substance is ordinarily included in the mineral estate, is a component or constituent of a granted substance, and whether the substance is “rare and exceptional in character.”¹⁴ For example, in *Murray v. BEJ Minerals*, the Montana Supreme Court looked to the language of the mineral reservation, the circumstances surrounding the transaction, and various definitions of “mineral” and “fossil” found in Montana statutes to conclude that the fossilized remains of two “dueling dinosaurs,” a Triceratops skull, and a Tyrannosaurus Rex, were not included in a mineral reservation.¹⁵ Despite the fact that the fossils had undergone a mineralization process, the court rejected a purely scientific interpretation and found that the parties would not have intended fossils to be included as minerals.¹⁶ In *Carbon County v. Union Reserve Coal Co.* the Montana Supreme Court determined that because CBM “is not a constituent part of the coal” it was not included in a grant of “coal and coal rights.”¹⁷ The court found that the grant of the coal estate conveyed

⁸ *Murray v. BEJ Minerals, LLC*, 2020 MT 131, ¶ 20; *see also* MONT. CODE ANN. § 28-3-101 *et. seq.* (West 2019).

⁹ MONT. CODE ANN. § 28-3-301 (West 202).

¹⁰ MONT. CODE ANN. § 28-3-303 (West 2020); MONT. CODE ANN. § 28-3-401 (West 2020).

¹¹ MONT. CODE ANN. § 28-3-402 (West 2020); *see also* *Murray*, 2020 MT at ¶ 22.

¹² *See* *Farley v. Booth Bros. Land & Livestock Co.*, 890 P.2d 377, 379 (Mont. 1995).

¹³ *Murray v. BEJ Minerals, LLC*, 2020 MT 131, ¶ 17.

¹⁴ *Hart v. Craig*, 216 P.3d 197, 198 (Mont. 2009).

¹⁵ *Murray*, 2020 MT at ¶ 24-30.

¹⁶ *Id.*

¹⁷ *Carbon City v. Union Reserve Coal Co.*, 898 P.2d 380, 688 (Mont. 1995).

no ownership interest in the CBM, but only a right to extract and store it for safety purposes incidental to coal mining.¹⁸ Montana courts have not ruled on whether CO₂ is conclusively considered part of the mineral estate. If confronted with a question regarding ownership of natural CO₂, Montana courts will examine the conveyance creating the mineral estate, as well as extrinsic evidence to determine whether the grant or reservation was intended to include CO₂.

Montana has statutorily declared that earlier-in-time mining claims on federal public lands for hard-rock minerals, such as gold and silver, take precedence over claims filed or amended later.¹⁹ However, Montana has not developed any further law concerning conflicts amongst mineral estates. In the absence of express contractual provisions, it is unclear whether courts would apply a first-in-time default rule or some other rule to development of conflicting mineral estates, such as oil and gas or coal.

Split Estates

A mineral estate in Montana enjoys an implied servitude to reasonable use of the surface. The implied easement has been modified by Montana’s split estate statute.²⁰ This statute imposes notice and compensation requirements on oil and gas operators.²¹ Before beginning surface disturbing activities, an operator must provide the surface owner with at least 20 days’ notice “to enable the surface owner to evaluate the effect of drilling operations on the surface owner’s use of the property.”²² The statute further entitles the surface owner to compensation for “loss of agricultural production and income, lost land value, and lost value of improvements” caused by the operator,²³ as well as any damage caused by a lack of ordinary care on the part of the operator.²⁴ In the event an agreement is not reached regarding damages, the surface owner may bring an action against the operator in the local district court.²⁵

Montana courts will likely find that CO₂ injectors may use pore space for storage incidental to development of the mineral estate.²⁶ However, use of pore space, as part of the surface estate, must be limited to that which is reasonably necessary to development of the mineral estate.²⁷

¹⁸ *Id.*

¹⁹ MONT. CODE ANN. § 82-2-110 (West 2019).

²⁰ *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 770 (Mont. 2011).

²¹ MONT. CODE ANN. § 82-10-501(2)(c) (West 2019).

²² MONT. CODE ANN. § 82-10-503(1) (West 2020).

²³ MONT. CODE ANN. § 82-10-504 (West 2020).

²⁴ MONT. CODE ANN. § 82-10-505 (West 2020).

²⁵ MONT. CODE ANN. § 82-10-508 (West 2020).

²⁶ *See, e.g.* *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766 (Mont. 2011).

²⁷ *Id.*

Pore Space Ownership

The Montana Supreme Court has held that pore space belongs to the surface estate, and that the reasonable use doctrine extends to use of the pore space.²⁸ In *Burlington Res. Oil & Gas Co., LP v. Lang & Sons, Inc.*, the Montana Supreme Court held that an oil and gas operator was entitled to dispose of wastewater produced in unit operations in the pore space belonging to one of the surface owners with an interest in the unit.²⁹ The surface owner sought to receive compensation for that use pursuant to the split estate statute, but the court found no evidence that use of the pore space caused a loss in agricultural production or income, or devaluation of the surface or any improvements.³⁰ Because the surface owner had failed to demonstrate the required damages, the court held that he could not recover under the split estate statute.³¹ The court went on to hold, however, that where the required damage is demonstrated, the split estate statute “could encompass damage sustained by a surface estate owner for the use of pore space.”³²

Water Rights

Montana adheres to the doctrine of prior appropriation for water administration.³³ The Montana Constitution declares that “[a]ll surface, underground, flood, and atmospheric waters within the boundaries of the state are property of the state . . . and are subject to appropriation for beneficial uses[.]”³⁴ A person must apply for and receive a permit from the Montana Department of Natural Resources and Conservation (“MDNRC”) prior to appropriation or construction of water “diversion, impoundment, withdrawal, or related distribution works.”³⁵ However, the production, use, and disposal of produced water from oil and gas operations is under the jurisdiction of the Montana Board of Oil and Gas Conservation.³⁶

Water appropriations, other than those for produced water, “pass with a conveyance of the land or transfer by operation of law[.]”³⁷ A “conveyance or reservation of a water right” separate from the land are

subject to the approval of the MDNRC.³⁸ This approval hinges, in part, on whether existing waters rights or other perfected or planned uses and developments for which a permit has been issued will be adversely affected by the transfer.³⁹

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.⁴⁰ Any condemnation of property in relation to this power must be conducted pursuant to Montana’s eminent domain statutes.⁴¹

Lithium Ownership and Extraction

Our research revealed no statutes or case law relating to lithium extraction in Montana. Montana has no history of lithium production and there are no known economically viable deposits of lithium in the state.⁴²

Classification of CO₂: Pollutant

For the purpose of oil and gas production taxes in Montana, “gas” is defined as “natural gas and other fluid hydrocarbons, other than oil, produced at the wellhead.” Unlike many other western states in this study, Montana’s revenue code does not provide for the taxation of CO₂ as a commodity. There are no CO₂ producing wells within the state at this time.⁴³

Montana regulates CO₂ as a pollutant. The Clean Air Act of Montana⁴⁴ defines “air pollutants” to mean one or more air contaminants, including those regulated by section 7412 and Subchapter V of the federal Clean Air Act, which includes CO₂.⁴⁵ In addition, “air contaminant” is defined to mean, *inter alia*, fumes, vapor, gas, or any combination thereof.⁴⁶

²⁸ *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 770 (Mont. 2011).

²⁹ *Id.*, at 770-71.

³⁰ *Id.*

³¹ *Id.*, at 771.

³² *Id.*

³³ See MONT. CODE ANN. § 85-2-401(1) (West 2019) (stating that for appropriations issued after 1973, “[a]s between appropriators, the first in time is the first in right”).

³⁴ MONT. CONST. art. IX, § 3; see also MONT. STAT. ANN. § 85-2-102(5) (West 2019) (defining “beneficial use”).

³⁵ MONT. CODE ANN. § 85-2-302(1) (West 2020).

³⁶ MONT. CODE ANN. § 85-2-510 (West 2020).

³⁷ MONT. CODE ANN. § 85-2-403(1) (West 2020).

³⁸ MONT. CODE ANN. § 85-2-403(2) (West 2020).

³⁹ MONT. CODE ANN. § 85-2-402(2) (West 2020).

⁴⁰ MONT. CODE ANN. § 7-13-4405 (West 2020); see also MONT. CODE ANN. § 7-13-4404 (West 2020).

⁴¹ MONT. CODE ANN. § 7-13-4404 (West 2020).

⁴² Personal communication with Stanley Korzeb, Economic Geologist & Research Professor, Montana Bureau of Mines and Geology (June 16, 2020).

⁴³ Personal communication with Ben Jones, Petroleum Engineer, Montana Board of Oil and Gas Conservation (July 6, 2020).

⁴⁴ MONT. CODE ANN. § 75-2-101 (West 2020) (providing that §§ 75-2-101 through 75-2-429 is “known and may be cited as the ‘Clean Air Act of Montana’”).

⁴⁵ MONT. CODE ANN. § 75-2-103(2) (West 2020).

⁴⁶ MONT. CODE ANN. § 75-2-103(1) (West 2020).

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The Montana Board of Oil and Gas Conservation (“MBOGC”) administers Montana’s oil and gas laws to prevent waste and regulate well drilling, production, plugging, chemical treatment, spacing, enhanced recovery operations, and geophysical seismic exploration.⁴⁷

All oil and gas operators are required to obtain a drilling permit before beginning operations. To prevent waste and protect correlative rights, the MBOGC is authorized to establish either temporary or permanent spacing units for discovered pools.⁴⁸ If a spacing unit encompasses multiple separately owned tracts, the separate owners may voluntarily pool their interests.⁴⁹ If the owners do not voluntarily pool their interests, on application of at least one interested party or person who has drilled or proposes to drill a well the MBOGC may order compulsory pooling of their interests.⁵⁰ The MBOGC may also order unitization of a pool for enhanced recovery operations which exceed the boundaries of a single spacing unit if the leasehold interest owner(s) of at least 60% of the surface area over the pool apply for a hearing on unitization.⁵¹ For unitization, the MBOGC is required to find, “based on evidence presented at the hearing,” that unitization is “reasonably necessary to increase . . . recovery of oil or gas,” that the additional recovery is greater than projected costs, and that the limits of the pool have been “reasonably defined.”⁵²

The MBOGC was granted primacy over Class II wells on November 19, 1996.⁵³ The MBOGC regulates Class II well operations to prevent subsurface escape of oil or gases into neighboring strata or geologic formations, as well as to ensure restoration of surface lands after drilling operations have ceased.⁵⁴ The MBOGC is authorized to charge annual fees of up to \$300 on all Class II injection

wells,⁵⁵ though the current annual fee is only \$200.⁵⁶ The MBOGC, under its statutorily granted rulemaking powers, has promulgated regulations requiring an MBOGC permit for new injection projects and prior to converting, constructing, or operating new Class II injection wells, “for the purpose of disposal, or as part of an enhanced recovery project, or for the storage of liquid hydrocarbons[.]”⁵⁷ Regulations require demonstration of mechanical integrity⁵⁸ and mitigation to prevent fluid migration⁵⁹ to protect underground sources of drinking water.⁶⁰

The MBOGC regulates underground storage of natural gas, other than that for use in interstate commerce, to promote conservation and the public interest.⁶¹ A natural gas public utility may exercise eminent domain to acquire an underground reservoir, defined as “any subsurface sand, stratum, or formation of the earth suitable for the injection and storage of natural gas”⁶² for the storage of natural gas.⁶³

“The MBOGC regulates Class II well operations to prevent subsurface escape of oil or gases into neighboring strata or geologic formations, as well as to ensure restoration of surface lands after drilling operations have ceased.”

⁴⁷ MONT. CODE ANN. § 82-11-124 (West 2020); MONT. CODE ANN. § 82-1-101 (West 2020); *see also* MONT. CODE ANN. § 82-11-121 (West 2020).

⁴⁸ MONT. CODE ANN. § 82-11-201 (West 2020).

⁴⁹ MONT. CODE ANN. § 82-11-202(1)(a) (West 2020).

⁵⁰ MONT. CODE ANN. § 82-11-202(1)(b) (West 2020).

⁵¹ MONT. CODE ANN. § 82-11-204(1) (West 2020).

⁵² MONT. CODE ANN. § 82-11-205 (West 2020).

⁵³ *See* Mont. Bd. of Oil and Gas Conservation; Underground Injection Control (UIC) Program; Primacy Program Approval, 61 Fed. Reg. 58932-01 (proposed Oct. 4, 1995) (codified at 40 C.F.R. § 147.1350); *see also* MONT. CODE ANN. § 82-11-111(5) (West 2020).

⁵⁴ MONT. CODE ANN. § 82-11-123 (West 2020).

⁵⁵ MONT. CODE ANN. § 82-11-137 (West 2020).

⁵⁶ MONT. ADMIN R. 36.22.1423(1) (2020).

⁵⁷ MONT. ADMIN R. 36.22.1402 (2020); *see also* MONT. ADMIN R. 36.22.1403 (providing contents and requirements of applications filed with the MBOGC).

⁵⁸ MONT. ADMIN R. 36.22.1406(1) (2020).

⁵⁹ *Id.*

⁶⁰ MONT. ADMIN R. 36.22.1406(2) (2020).

⁶¹ MONT. CODE ANN. § 82-10-302 (West 2020).

⁶² MONT. CODE ANN. § 82-10-301 (West 2020).

⁶³ MONT. CODE ANN. § 82-10-303 (West 2020).

Pipeline Regulation

The Montana Public Service Commission (“MPSC”) enforces federal pipeline safety regulations on all intrastate natural gas pipelines.⁶⁴ The PHMSA regulates the safety of interstate natural gas pipelines, as well as all crude oil or petroleum lines, whether interstate or intrastate.⁶⁵

The Montana Department of Environmental Quality (“MDEQ”) and Board of Environmental Review regulate the siting of all interstate and intrastate pipelines greater than 25 inches in diameter and 50 miles in length under the Montana Major Facility Siting Act.⁶⁶ As described in the Industrial Siting section below, all such pipelines must operate in compliance with MDEQ regulations.⁶⁷

State Environmental Laws

The EPA manages Montana’s UIC program, except with respect to Class II wells.⁶⁸ The Montana legislature has enacted contingency provisions relating to CO₂ geologic storage to become effective if and when Montana is granted primacy over Class VI wells,⁶⁹ although Montana has not yet applied for such primacy.⁷⁰

Industrial Siting Requirements

The Montana Department of Environmental Quality and Board of Environmental Review administer the Montana Major Facility Siting Act,⁷¹ which governs, among other things, siting of “each pipeline, whether partially or wholly within the state, greater than 25 inches in inside diameter and 50 miles in length, and associated facilities” with limited exceptions.⁷² Notably, where an operator negotiates voluntary agreements with over 75% of the owners of the property through which the pipeline will run, the operator does not need a siting permit from the Department of Environmental Quality.⁷³ Operators of all such pipelines must apply for and receive a certificate

and permits before installing a pipeline. The application must describe the need for the pipeline, the proposed location, and a summary of any preexisting studies on the impact of the pipeline, alternate locations, and the comparative benefits and detriments of each proposed location.⁷⁴ The MDEQ is required to monitor pipelines for continuing compliance with siting laws and regulations.⁷⁵

Local Regulation

Montana allows its counties or cities to execute self-government, or home rule, charters.⁷⁶ Montana statutes on land use, local planning, and county zoning prohibit local governments from enacting rules or ordinances that “prevent the complete use, development, or recovery of any mineral . . . resources by the [mineral owner]” other than for sand and gravel.⁷⁷ In *Missoula County v. America Asphalt*, the Montana Supreme Court held that these statutes require “a county [to] at least allow the activities necessary to develop the resource to a point at which it can be effectively utilized” noting a “reasonable construction of these broad statutes depends . . . on the circumstances in which they are applied.”⁷⁸

Other statutory provisions allow real property owners to band together to create “planning and zoning districts.”⁷⁹ Such districts are not bound by the statutes preventing counties from banning mineral estate development. Rather, they are only prevented from regulating “lands used for grazing, horticulture, agriculture, or the growing of timber.”⁸⁰ In 2005, landowners in Gallatin County took advantage of these provisions to prevent a proposed coal bed methane gas operation.⁸¹ A challenge to this use of the planning and zoning district statute was never successfully brought to trial, so its viability as a means of preventing mineral or oil and gas production has not been tested.

⁶⁴ MONT. CODE ANN. § 75-20-211(1)(a) (West 2019).

⁶⁵ MONT. CODE ANN. § 75-20-402 (West 2019).

⁶⁶ MONT. CONST. art. XI, §§ 4-6.

⁶⁷ MONT. CODE ANN. § 76-1-113 (West 2019); MONT. CODE ANN. § 76-2-209 (West 2019).

⁶⁸ *Missoula Cty. v. Am. Asphalt, Inc.*, 701 P.2d 990, 992 (Mont. 1985).

⁶⁹ MONT. CODE ANN. § 76-2-101 (West 2019).

⁷⁰ MONT. CODE ANN. § 76-2-109 (West 2019).

⁷¹ David J. Katz, *Citizen Initiated Zoning: A Way to Restore Fairness to Oil and Gas Drilling in Montana*, PRESERVE THE BEARTOOTH FRONT (Aug. 13, 2014), <https://preservethebeartoothfront.com/2014/08/13/citizen-initiated-zoning-a-way-to-restore-fairness-to-oil-and-gas-drilling-in-montana/>; *Company Relinquishes Four Drilling Leases Near Bozeman Pass*, BILLINGS GAZETTE (Jan. 31, 2006), https://billingsgazette.com/news/state-and-regional/montana/company-relinquishes-four-drilling-leases-near-bozeman-pass/article_0b10973d-2601-5791-b1c7-5382e385d543.html.

⁶⁴ MONT. CODE ANN. § 69-3-207 (West 2020); *see also* MONT. ADMIN. R. 38-5-2201 to 2209 (2020).

⁶⁵ *Id.*

⁶⁶ Montana Major Facility Siting Act, § 75-20-101 to 1205 (West 2020).

⁶⁷ *Id.*

⁶⁸ 40 C.F.R. § 147.1351 (2020).

⁶⁹ MONT. CODE ANN. § 82-11-111 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 14).

⁷⁰ Personal communication with Jim Halvorson, Administrator, Board of Oil & Gas Conservation, Billings Headquarters (June 23, 2020).

⁷¹ Montana Major Facility Siting Act, § 75-20-101 to 1205 (West 2019);

⁷² MONT. CODE ANN. § 75-20-104(9)(b) (emphasis added).

⁷³ *Id.*

Tribal Lands

Montana encompasses seven reservations belonging to federally recognized Indian tribes, and an additional federally recognized band of Chippewa Indians which is without a reservation.⁸² In 1951, Montana created the Office of Indian Affairs to serve as a liaison for communications between these tribes and the state.⁸³

The EPA manages the UIC program for all tribes in Montana, with the exception of Class II wells on the Fort Peck Tribes' reservation.⁸⁴ The Fort Peck Tribes were granted primacy over Class II injection wells within their territory on October 27, 2008.⁸⁵ The Fort Peck Tribes require that any Class II injection well operator apply for and receive a permit from the Fort Peck Tribes' Office of Environmental Protection before commencing any operations.⁸⁶ Operators must comply with all federal requirements when submitting an application, and are also required to post a "surety bond to demonstrate financial responsibility[.]"⁸⁷ Operators must work with a Liaison Officer appointed by the Tribal Employment Rights Office ("TERO") to communicate with "the Tribe's oil and gas committee, the Tribal Minerals Resources Department, the TERO, and the Bureau of Indian Affairs."⁸⁸ The Liaison Officer should keep oil and gas operations away from "tribal historical sites[.]"⁸⁹

The BIA is responsible for leasing, and the BLM has primary responsibility for oil and gas regulation on the remaining reservations.⁹⁰

Eminent Domain:

The Montana Constitution limits eminent domain authority to those that benefit designated "public uses"⁹¹ and requires payment of "just compensation" when such authority is exercised.⁹² Any estate in land, "up to and including a fee simple interest," may be taken for a public use.⁹³ Before exercising eminent domain the condemnor must demonstrate that the taking is in the public interest⁹⁴ and that the proposed use is situated to provide "the greatest public good and the least private injury[.]"⁹⁵

Common carrier pipelines have been designated as a public use with eminent domain powers, which must be exercised in accordance with Mont. Stat. Ann. Title 70, Chapter 30.⁹⁶ A condemnor may "enter upon and condemn the land, rights-of-way, easements, and property of any person or corporation necessary for the construction, maintenance, or authorization of the entity's common carrier pipeline."⁹⁷ Any person or entity that owns, operates, or manages a pipeline "for the public or for hire," and which is used in the transportation of "crude petroleum, coal, or the products of crude petroleum or coal or of carbon dioxide from a plant or facility that produces or captures carbon dioxide" is designated as a common carrier.⁹⁸ Montana defines a "plant or facility that produces or captures carbon dioxide" as "a facility that produces a flow of carbon dioxide that can be sequestered or used in a closed-loop enhanced oil recovery operation."⁹⁹ The statute excludes wells primarily producing carbon dioxide from this definition.

Natural gas public utilities¹⁰⁰ may exercise eminent domain power to take "any sand, stratum, or formation for use as an underground natural gas storage reservoir."¹⁰¹ Condemnation of natural gas storage rights does not "prejudice . . . the rights of the [owners] of the land or the oil, gas, or other mineral rights in the land to drill or bore through the [formation] . . . [to] explore for, produce, process, treat, processing, or market [the

⁸² MONTANA GOVERNOR'S OFFICE OF INDIAN AFFAIRS, TRIBAL NATIONS, <https://tribalnations.mt.gov/tribalnations> (last visited June 17, 2020).

⁸³ MONTANA GOVERNOR'S OFFICE OF INDIAN AFFAIRS, ABOUT US, <http://tribalnations.mt.gov/aboutus> (last visited June 17, 2020).

⁸⁴ 40 C.F.R. § 147.1350 (2020).

⁸⁵ See Fort Peck Assiniboine and Sioux Tribes in Montana; Underground Injection Control (UIC) Program; Primacy Approval and Minor Revisions, 73 Fed. Reg. 63639-02 (proposed Jan. 30, 2008) (codified at 40 C.F.R. § 147.3200).

⁸⁶ FORT PECK TRIBES' COMPREHENSIVE CODE OF JUSTICE § 22-220, <https://static1.squarespace.com/static/594c44e12cba5ec4cb294563/t/5b1854e103ce64e055c912d8/1528321250571/chapter2.pdf> (last visited July 2, 2020).

⁸⁷ *Id.*, at § 22-221.

⁸⁸ *Id.*, at § 13-701 to 704.

⁸⁹ *Id.*, at § 13-703.

⁹⁰ 25 U.S.C. 396a *et seq.* (2020); Development of Tribal Mineral Resources, 25 U.S.C. § 2101 to 08 (2020); 25 C.F.R. §§ 200-227.3 (2020).

⁹¹ MONT. CODE ANN. § 70-30-102 (West 2020).

⁹² MONT. CONST. art. II, § 29.

⁹³ MONT. CODE ANN. § 70-30-104 (West 2020).

⁹⁴ MONT. CODE ANN. § 70-30-111 (West 2020).

⁹⁵ MONT. CODE ANN. § 70-30-110 (West 2020).

⁹⁶ MONT. CODE ANN. § 70-30-102(20) (West 2020).

⁹⁷ *Id.*

⁹⁸ MONT. CODE ANN. § 69-13-101(1) (West 2020) (emphasis added).

⁹⁹ MONT. CODE ANN. § 15-6-158(2)(g) (West 2020); see also MONT. CODE ANN. § 69-13-101(2) (West 2020) (providing that "[f]or the purposes of this chapter, 'plant or facility that produces or captures carbon dioxide' has the meaning provide for in 15-6-58").

¹⁰⁰ MONT. CODE ANN. § 82-10-301(4) (West 2020).

¹⁰¹ MONT. CODE ANN. § 70-30-105 (West 2020); MONT. CODE ANN. § 70-30-104(a)(v) (West 2019); see also MONT. CODE ANN. § 82-10-303 (West 2020).

minerals].”¹⁰² Condemned interests for natural gas storage terminate upon “abandonment or ... cessation” of the use of the property for a period of one year.¹⁰³ Upon termination, ownership of the natural gas remaining in the reservoir vests with the surface owner.¹⁰⁴

Geologic CO₂ Storage Regulation and Incremental Storage:

The Montana legislature has enacted contingency provisions relating specifically to CO₂ geologic storage.¹⁰⁵ These provisions will become effective only upon Montana being granted primacy over the Class VI UIC program,¹⁰⁶ although Montana has not yet applied for such primacy.¹⁰⁷ Once effective, these provisions will give the MBOGC complete regulatory authority over CO₂ geologic storage.¹⁰⁸

The contingency statutes define a geologic storage reservoir as “a subsurface sedimentary stratum, formation, aquifer, cavity, or void, whether natural or artificially created, including vacant or filled reservoirs, saline formations, and coal seams suitable for or capable of being made suitable for injecting and storing carbon dioxide.”¹⁰⁹ CO₂-EOR wells may be converted into geologic storage reservoirs with the permission of the MBOGC.¹¹⁰

“The Montana legislature has enacted contingency provisions relating specifically to CO₂ geologic storage.”

The statutes authorize the MBOGC to charge an annual fee of \$5,000 for each geologic sequestration well,¹¹¹ and require that a geologic storage operator post bond to cover liability for injected CO₂.¹¹² The MBOGC is also required to monitor and regulate storage reservoirs for CO₂ escape and induced seismicity.¹¹³ Additionally, the statutes apply MBOGC rules and regulations on pooling and unitization to CO₂ storage reservoirs.¹¹⁴

Pursuant to these contingency provisions, the operator of a CO₂ injection operation will maintain ownership and liability for injected CO₂, including liability for escaped or migrating CO₂, unless and until ownership and liability is transferred to the state.¹¹⁵ Transfer of liability to the state is a two-step process. Twenty-five years after injection the operator may receive certification of project

¹⁰² See MONT. CODE ANN. § 70-30-105 (West 2020); see also MONT. CODE ANN. § 70-30-106 (West 2020).

¹⁰³ MONT. CODE ANN. § 70-30-104(a)(v) (West 2020).

¹⁰⁴ *Id.*

¹⁰⁵ MONT. CODE ANN. § 82-11-111 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 14).

¹⁰⁶ 2009 Mont. Laws ch. 474, § 31. Montana has not yet requested primacy over Class VI wells. Personal communication with Jim Halvorson, *supra* note 69.

¹⁰⁷ Personal communication with Jim Halvorson, *supra* note 69.

¹⁰⁸ MONT. CODE ANN. § 82-11-111 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 14).

¹⁰⁹ MONT. CODE ANN. § 82-11-101 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 12).

¹¹⁰ MONT. CODE ANN. § 82-11-184 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 5).

¹¹¹ MONT. CODE ANN. § 82-11-137 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 20).

¹¹² MONT. CODE ANN. § 82-11-123 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 3).

¹¹³ MONT. CODE ANN. § 82-11-123 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 17). see also 2009 Mont. Laws ch. 474, § 12; 2009 Mont. Laws ch. 474, § 25.

¹¹⁴ MONT. CODE ANN. § 82-11-201 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 23).

¹¹⁵ MONT. CODE ANN. § 82-11-182 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 3).

completion if the operator shows, among other things, that the “geologic storage reservoir will retain the carbon dioxide stored in it.” The operator must demonstrate that the stored CO₂ is stable, meaning that it is “stationary or chemically combined” and will not migrate into other geologic formations, and that operation wells and facilities have been properly plugged or removed unless needed in the “postclosure period.”¹¹⁶ For the subsequent 25 years, the storage operator must continue to provide a surety bond and “adequate monitoring” of the site.¹¹⁷ At the conclusion of this combined 50-year term, the operator may transfer title of the injected CO₂ to the state if the past 25 years of monitoring have demonstrated that the “reservoir will maintain its structural integrity” and the CO₂ will not migrate out of the injection formation.¹¹⁸ Once the transfer is complete, the State of Montana acquires all the rights, interests, and responsibilities of the stored CO₂ and the “geologic storage reservoir,” and the injection operator is released from “all regulatory requirements and liability.”¹¹⁹ Following transfer, the state will monitor and maintain the geologic storage reservoir until the responsibility is assumed by the federal government.¹²⁰



“For the subsequent 25 years, the storage operator must continue to provide a surety bond and “adequate monitoring” of the site. ”

¹¹⁶ MONT. CODE ANN. § 82-11-183 (West 2020) (effective on the date that the Board of Oil and Gas Conservation is granted primacy to administer activities at carbon dioxide sequestration wells by the United States Environmental Protection Agency as established in 2009 Mont. Laws ch. 474, § 4).

¹¹⁷ *Id.*

¹¹⁸ *Id.*

¹¹⁹ *Id.*

¹²⁰ *Id.*

NEW MEXICO

Executive Summary

New Mexico increasingly relies on CO₂-EOR for oil and gas production and has significant CO₂ sequestration potential. New Mexico has clear laws relating to eminent domain for pipelines, produced water disposal, natural gas storage, and growing regulation of induced seismicity. It does not yet specifically regulate CO₂ storage. Uncertainties regarding use of pore space and conflicts between competing mineral estates may complicate potential CO₂ storage proposals.

Background:

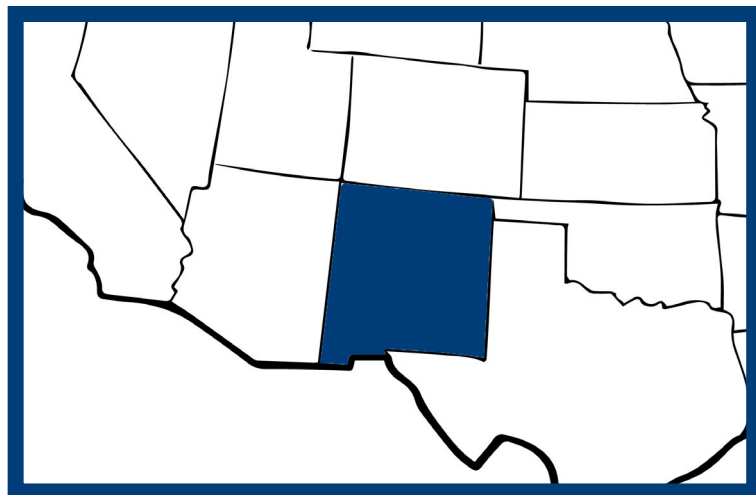
New Mexico includes federal, state, fee, and tribal land. Of the 77,886,080 acres of land within the state's borders, 27,001,583 acres (34.6%) is federally owned or managed. Federal land ownership in New Mexico is dispersed relatively evenly, save for the northeast portion of the state.

New Mexico operates under a common law legal system. The state's district courts serve as trial courts of general jurisdiction, and the district court system is composed of 13 judicial districts. The New Mexico Court of Appeals is the first avenue for an appeal from a district court's decision. The New Mexico Supreme Court is the court of last resort in the state.

CO₂-EOR in New Mexico is governed by a combination of state and local entities. While the New Mexico Oil Conservation Division ("NMOCD") bears primary regulatory responsibility, other interested agencies include the Water Quality Control Commission ("WQCC") and the New Mexico Environment Department ("NMED"). New Mexico counties and the Navajo Nation also have areas of regulatory control.

CO₂-EOR in New Mexico:

The Permian Basin in southeastern New Mexico is a prolific oil and gas basin and among the most developed CO₂-EOR recovery fields in the world.¹ It is responsible for approximately 30% of the total oil production in the U.S. In 2019 alone, 152,868,115 Mcf of CO₂ were injected into the Permian in Lea County for EOR.² The Permian



Basin contains a remaining 15.9 billion barrels of oil recoverable through EOR procedures.³ New Mexico's oil and gas fields are estimated to have a CO₂ storage capacity of six gigatons, while its saline aquifers are projected to have a storage capacity of roughly 12 gigatons.⁴ New Mexico produces a significant amount of natural CO₂ from the Bravo Dome, which covers approximately 800,000 acres in Union and Harding Counties.⁵ In 2019, Harding County produced 41,301,399 Mcf of natural CO₂ and Union County produced an additional 40,622,333 Mcf.⁶ Enchant Energy recently proposed a CO₂ capture project from the San Juan Generating Station near Farmington, New Mexico.⁷ Its business model relies, in part, on sales of CO₂ for tertiary recovery in the Permian basin.⁸

visited June 3, 2020)

³ NAT'L ENERGY TECH. LABORATORY, CARBON DIOXIDE ENHANCED OIL RECOVERY: UNTAPPED DOMESTIC ENERGY SUPPLY AND LONG TERM CARBON STORAGE SOLUTION, DEP'T OF ENERGY, 16, https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf (last visited July 21, 2020).

⁴ MARK E. FESMIRE ET AL., A BLUEPRINT FOR THE REGULATION OF GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE IN NEW MEXICO, NMEN-NRD OIL CONSERVATION DIV., 14 (2007).

⁵ U.S. DEP'T. OF ENERGY – OFFICE OF SCI. AND TECH. INFO., GEOLOGY OF BRAVO DOME CARBON DIOXIDE GAS FIELD, NEW MEXICO, <https://www.osti.gov/biblio/5786834> (last visited July 17, 2020).

⁶ NEW MEXICO OIL CONSERVATION DIV., CTY PRODUCTION AND INJECTION SUMMARY BY MONTH, <https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Reporting/Production/CountyProductionInjectionSummaryReport.aspx?Year=2019> (last visited June 3, 2020)

⁷ Farmington and Enchant Provide Response to IEEFA Analysis of San Juan Generating Station Carbon Capture Project, ENCHANT ENERGY CORP., <https://www.enchantenergy.com/farmington-and-enchant-provide-response-to-ieefa-analysis-of-san-juan-generating-station-carbon-capture-project/> (last visited July 18, 2020).

⁸ *Id.*

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

When interpreting mineral conveyances, New Mexico courts focus on identifying the intent of the parties.⁹ If the intent is not clear from the four corners of the document, courts engage in a fact-specific inquiry and may look to parol, or extrinsic, evidence to analyze the parties' intent.¹⁰

New Mexico courts have found that the term mineral, by itself, may be ambiguous, and that the "category of 'minerals' is a flexible one."¹¹ Accordingly, New Mexico courts look to the intent of the parties to determine the extent that general grants of minerals encompass a specific substance. In so doing, courts may "look to evidence outside the face of the contract" to determine the meaning intended for "mineral" in a general grant or reservation.¹² Certain substances, such as "rocks," are normally given their "common and ordinary meaning[.]"¹³ In *Bogle Farms Inc. v. Baca*, the court ultimately concluded that sand and gravel were not included in the general mineral reservation under analysis because the parties had not bargained to include it in the mineral estate, and therefore had not intended such.¹⁴ In 2011, in *Prather v. Lyons*, a New Mexico Appellate Court relied on the reasoning in *Bogle Farms* to hold that the court must determine the intent of the parties in order to analyze the meaning of the term "mineral" in a general mineral reservation.¹⁵ For instruments determined to be ambiguous, New Mexico courts will likely perform a fact-specific inquiry into extrinsic evidence to determine whether any given conveyance includes CO₂.

New Mexico Courts have not ruled on whether CO₂ is included in a general grant of minerals or a grant of "gas." New Mexico statutes define CO₂ as a natural gas for purposes of oil and gas leases on state trust land.¹⁶ Furthermore, New Mexico's pipeline laws include statutory definitions for "oil" and "gas,"¹⁷ which would likely include CO₂ as a "natural gas" or, potentially, as a "corrosive gas." However, statutory definitions may not be determinative as to intent between parties to a

conveyance. New Mexico courts have not determined whether CO₂ is included in a conveyance of "gas" in a private transfer of mineral interests.

New Mexico recognizes that a mineral interest is an interest in real property.¹⁸ In New Mexico, a mineral interest includes "the following incidents: the right to receive bonuses, delay rentals, and royalties . . . ; [and] the right to execute oil, gas, and mineral leases . . ." ¹⁹ A mineral interest may be created by language in a deed, and the deed may strip a mineral interest of "one or more of its normal incidents[.]" ²⁰ Thus, it is possible for multiple split mineral estates to exist. On state land, New Mexico statutes provide that where oil and gas leases conflict with leases for other minerals, the commissioner of public lands may extend or temporarily suspend oil or gas operations while production of the other minerals proceed in order to prevent waste of all substances.²¹ For instance, oil and gas operations are prohibited in any area with "commercial deposits of potash" if the operations will result in waste or loss of the potash.²² New Mexico has not, either legislatively or judicially, addressed conflicts between coal leases, oil and gas leases, and other mineral estates on private land. If confronted with the issue they may extend the accommodation doctrine formerly applied to surface estates to competing mineral estates.²³

Split Estates

New Mexico courts impose a common law implied servitude on the surface estate for reasonable development of a severed mineral estate.²⁴ New Mexico statutorily amended the scope of the common law easement through the Surface Owners Protection Act ("SOPA").²⁵ The SOPA requires oil and gas operators to provide surface owners with sufficient notice at least 30 days prior to beginning oil and gas operations so that the surface owner may "evaluate the effect of the operations on the property."²⁶ The notice must also propose a "surface use and compensation agreement" and an "offer of compensation for damages to the surface affected by oil and gas operations."²⁷ If no agreement is reached within 30 days of the notice, the operator may

¹⁸ *Hydro Res. Corp. v. Gray*, 17 P.3d 749, 759 (N.M. 2007).

¹⁹ *HNG Fossil Fuels Co. v. Roach*, 656 P.2d 879, 882 (N.M. 1982).

²⁰ *Id.*

²¹ N.M. STAT. ANN. § 19-10-8 (West 2020).

²² N.M. STAT. ANN. § 70-2-3(F) (West 2020).

²³ *See Amoco Production Co. v. Carter Farms Co.*, 703 P.2d 894 (N.M. 1985).

²⁴ *See, e.g., McNeill v. Burlington Res. Oil & Gas Co.*, 182 P.3d 121, 129 (N.M. 2008).

²⁵ N.M. STAT. ANN. § 70-12-1 et. seq. (West 2020).

²⁶ N.M. STAT. ANN. § 70-12-5 (West 2020).

²⁷ § 70-12-5(B).

⁹ *Atl. Ref. Co. v. Beach*, 436 P.2d 107, 110 (N.M. 1968); *citing*

Sharpe v. Smith, 360 P.2d 917, 918 (N.M. 1961).

¹⁰ *HNG Fossil Fuels Co. v. Roach*, 656 P.2d 879, 882 (N.M. 1982).

¹¹ *Prather v. Lyons*, 267 P.3d 78, 84 (N.M. 2011).

¹² *Bogle Farms, Inc. v. Baca*, 925 P.2d 1184, 1194 (N.M. 1996).

¹³ *Prather*, 267 P.3d at 89.

¹⁴ *Bogle Farms*, 925 P.2d at 1194.

¹⁵ *Prather*, 267 P.3d at 91-93.

¹⁶ N.M. STAT. ANN. § 19-10-2 (West 2020).

¹⁷ N.M. STAT. ANN. § 70-3-12 (West 2020).

enter onto the land to conduct oil and gas operations after depositing with a surety company a bond of \$10,000 per well.²⁸ Regardless of whether an agreement is reached, an operator is required to compensate the surface owner for agricultural loss or reduction in land or improvement value caused by oil and gas operations.²⁹ In 2015, the New Mexico Supreme Court found that SOPA imposes strict liability on oil and gas operators for surface damage.³⁰

Pore Space Ownership

There are no statutes or case law specifically pertaining to pore space ownership on split estates in New Mexico. However, early judicial decisions indicate that pore space may be considered part of the surface estate. In 1929, the New Mexico Supreme Court held that the holder of a mineral interest “is not the owner of the solids of the earth”³¹ Rather, the Court held that a mineral lease only “enable[d] the owner of the lease to use the soil in carrying out [extraction operations].”³² This conclusion is bolstered by *Snyder Ranches, Inc. v. Oil Conservation Comm’s of State of New Mexico*, which stated in dicta that a surface owner did have a right to sue a neighboring mineral interest holder for subsurface trespass.³³ Although New Mexico Courts interpret conveyances on an individual basis according to the intent of the parties, these cases indicate that in the absence of specific language to the contrary, New Mexico courts would likely find that the pore space is owned by the surface owner. In a split estate, the common law implied easement would entitle the mineral owner use of the pore space to the extent reasonably necessary for oil and gas extraction.

Water Rights

New Mexico applies the doctrine of prior appropriation to water administration. The Constitution of the State of New Mexico provides that “the unappropriated water of every natural stream, perennial or torrential, within the state of New Mexico, is hereby declared to belong to the public and to be subject to appropriation for beneficial use, in accordance with the laws of the state.”³⁴ Temporal priority is used to determine the superior right.³⁵ The state’s constitution also provides that “[b]eneficial use shall be the basis, the measure and the limit of the right to the use of water.”³⁶

²⁸ N.M. STAT. ANN. § 70-12-6 (West 2020).

²⁹ N.M. STAT. ANN. § 70-12-4 to 70-12-7 (West 2020).

³⁰ *Woody Inv., LLC v. Sovereign Eagle, LLC*, 362 P.3d 07, 110 (N.M. 2015).

³¹ *Jones-Noland Drilling Co. v. Bixby*, 282 P. 382, 383 (N.M. 1929).

³² *Id.*

³³ *Snyder Ranches, Inc. v. Oil Conservation Comm’n of State of N.M.*, 798 P.2d 587, 590 (N.M. 1990).

³⁴ N.M. CONST. art. 16, § 2.

³⁵ *Id.*

³⁶ N.M. CONST. art. 16, § 3.

Consistent with the constitution, New Mexico statutes set the procedure for water appropriation.³⁷ To acquire a right to appropriate water, an application must be made to the state engineer for a permit.³⁸ Unless appropriated for irrigation purposes, water rights are separate and distinct from the land,³⁹ and thus may be transferred and assigned apart from the land.⁴⁰ Following notice and a one-year opportunity to cure, water rights can be forfeited by nonuse.⁴¹

Groundwater is also subject to appropriation for beneficial use.⁴² Upon application and issuance of a permit, N.M. Stat. Ann. § 72-12-1.3, permits appropriation of groundwater for “drilling operations designed to discover or develop the natural mineral resources of the state.”⁴³ Each application for ground water appropriation is limited to no more than three acre-feet and a duration of no more than one year.⁴⁴ The state engineer will grant an application if, after an examination of the facts, it finds that the proposed use will not permanently impair any existing rights of other appropriators.⁴⁵

The ownership, regulation, and use of produced water is governed by the Produced Water Act.⁴⁶ This Act gives jurisdiction to the NMOCD to regulate produced water as provided in the Oil and Gas Act, and to the WQCC to regulate produced water under the Water Quality Act.⁴⁷ The working interest owners and operator of oil and gas wells have ownership of water produced from oil and gas wells and also the responsibility for disposal.⁴⁸ Ownership and responsibility for produced water is transferable. These rights include “the right to take possession of the produced water and to use, handle, dispose of, transfer, sell, convey, transport, recycle, reuse or treat the produced water and to obtain proceeds for any such uses.”⁴⁹ The operator is held to a reasonably prudent operator standard with respect to its use and disposition of produced water under the Act.⁵⁰

³⁷ N.M. STAT. ANN. § 72-1-1 (West 2020).

³⁸ N.M. STAT. ANN. § 72-1-2 (West 2020).

³⁹ *See Id.*; *See also Hydro Res. Corp. v. Gray*, 173 P.3d 749, 755 (N.M. 2007), *reh’g denied*.

⁴⁰ N.M. STAT. ANN. § 72-5-22 (West 2020).

⁴¹ N.M. STAT. ANN. § 72-5-28 (West 2020).

⁴² N.M. STAT. ANN. § 72-12-1 (West 2020).

⁴³ N.M. STAT. ANN. § 72-12-3 (West 2020); *see also* N.M. STAT. ANN. § 72-1-1.3 (West 2020) (stating that “only the application referred to in Section 72-12-3 NMSA 18978 shall be required”).

⁴⁴ N.M. STAT. ANN. § 72-12-1.3 (West 2020).

⁴⁵ *Id.*

⁴⁶ N.M. STAT. ANN. § 70-13-1 (West 2020) (providing that §§ 70-13-1 through -5 “may be cited as the ‘Produced Water Act’”).

⁴⁷ N.M. STAT. ANN. § 70-13-3 (West 2020).

⁴⁸ N.M. STAT. ANN. § 70-13-4 (West 2020).

⁴⁹ N.M. STAT. ANN. § 70-13-4(1).

⁵⁰ *Id.*

Municipalities have the authority to exercise eminent domain power to acquire water facilities, including wells, or water rights for the use and supply of water for sewage, private use, and public use.⁵¹ Municipalities must demonstrate that the water will be used for public health or safety purposes, or prove other necessity. Municipalities may only exercise eminent domain power in compliance with the Eminent Domain Code (discussed below).⁵² Municipalities may use this power to protect water facilities and water from pollution, and when this power is used for such a purpose, the jurisdiction of the municipality is extended.⁵³

New Mexico is unique in allowing all inhabitants the “right to construct, either private or common acequias, and to take water for said acequias from wherever they can.”⁵⁴ The state also provides acequias, or community ditches, with condemnation powers to condemn lands “where a new ditch for an acequia is to be made[,]” provided that just compensation has been appraised and paid.⁵⁵

Lithium Ownership and Extraction

Our search did not reveal any statutes, regulations, or case law in New Mexico with respect to extraction of lithium or classification of lithium with the mineral estate. Lithium-bearing minerals are present in various areas in New Mexico, although most known deposits are present in only uneconomic quantities. Lithium was produced during the early twentieth century in the Harding Mine,⁵⁶ the Pidlite Mine,⁵⁷ and the Petaca and Ojo Caliente mining districts,⁵⁸ although no lithium production has been recorded since 1950.⁵⁹ It is believed that there is current potential for economic production of lithium in the Lordsburg playa.⁶⁰

⁵¹ See N.M. STAT. ANN. § 3-27-1 (West 2020); see also N.M. STAT. ANN. § 3-27-2 (West 2020).

⁵² § 3-27-1(B).

⁵³ N.M. STAT. ANN. § 3-27-3(A) (West 2020) (explaining that the jurisdiction “extends within and without its boundary to: (1) all territory occupied by the water facilities; (2) all reservoirs, streams and other sources supplying the reservoirs and streams; and (3) five miles above the point from which the water is taken”).

⁵⁴ N.M. STAT. ANN. § 73-2-1 (West 2020).

⁵⁵ N.M. STAT. ANN. § 73-2-2 (West 2020).

⁵⁶ Personal communication with Virginia McLemore, Principal Senior Economic Geologist and Minerals Outreach Liaison, New Mexico Bureau of Geology and Mineral Resources, (June 10, 2020); Richard H Jahns & R.C. Ewing, *The Harding Mine, Taos County, New Mexico*, N.M. GEOL. SOC. (1976).

⁵⁷ *Id.*

⁵⁸ Virginia T. McLemore, *Rare Earth Elements (REE) In Proterozoic Peralkaline Igneous Rocks (Pajarito Mountain) and Pegmatites in New Mexico*, NM BUREAU OF GEOLOGY AND MINERAL RESOURCES, 6 (Prepublication Version 2020), <https://geoinfo.nmt.edu/staff/mclemore/documents/SME20McLemore.pdf>.

⁵⁹ Personal communication with Virginia McLemore, *supra* note 56.

⁶⁰ V.T. McLemore, *Critical Minerals in New Mexico*, NM BUREAU OF

“New Mexico is unique in allowing all inhabitants the “right to construct, either private or common acequias, and to take water for said acequias from wherever they can.”

Classification of CO₂: Commodity and Pollutant

New Mexico law classifies CO₂ as both a commodity and a pollutant. The Oil and Gas Severance Tax Act⁶¹ provides that CO₂ is a “product” that is subject to the imposition of a severance tax when it is severed and sold.⁶² Under this Act, a severance tax is levied on CO₂ at the rate of 3.75% of the taxable value determined pursuant to statute.⁶³ New Mexico also regulates CO₂ emissions from certain sources under the prevention of significant deterioration (“PSD”) permitting program.⁶⁴

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The New Mexico Oil and Gas Act (“NMOGA”) empowers the NMOCD with “jurisdiction and authority over all matters relating to the conservation of oil and gas . . .”⁶⁵ and is granted authority “to make and enforce rules, regulations and orders” to carry out those purposes.⁶⁶ The NMOCD regulates well plugging, spacing, and classification; the handling, treatment and disposal of produced water; and oil and gas operation accidents or incidents including escape of oil, gas or water into neighboring geological strata, fires, cave-ins,

GEOLOGY AND MINERAL RESOURCES, 4 (2018), https://geoinfo.nmt.edu/staff/mclemore/documents/19_132.pdf.

⁶¹ N.M. STAT. ANN. § 7-29-1 (West 2020) (providing that “Chapter 7, Article 29 NMSA 1978 may be cited as the ‘Oil and Gas Severance Tax Act’”).

⁶² N.M. STAT. ANN. § 7-29-2 (West 2020).

⁶³ N.M. STAT. ANN. § 7-29-4 (West 2020).

⁶⁴ See *infra* notes 102—109 and accompanying text.

⁶⁵ N.M. STAT. ANN. § 70-2-6 (West 2020).

⁶⁶ N.M. STAT. ANN. § 70-2-11 (West 2020).

and “blow-ups.”⁶⁷ It is also authorized to set production allowables within units and statewide.⁶⁸ It is specifically authorized to regulate injection and enhanced recovery operations.⁶⁹ The NMOCD is also directed to “adopt and administer rules on the conservation, the production and the prevention of waste of carbon dioxide . . . in the same manner as it regulates, conserves, and prevents waste of natural or hydrocarbon gas.”⁷⁰

The NMOCD administers the state’s Class II Injection well program. In addition to bonding and registration requirements,⁷¹ operators of Class II injection wells are subject to additional authorization⁷² and notice requirements.⁷³ Affected individuals are entitled to request a hearing before the NMOCD.⁷⁴ Authorization for Class II injection wells may be granted after a proper hearing.⁷⁵

The NMOGA authorizes compulsory pooling and unitization to allocate production and costs of unit operations and to combine multiple interests necessary for CO₂-EOR. When operations are conducted within a single spacing or proration unit (determined by the NMOCD),⁷⁶ the owners of the various separately owned interests may either voluntarily “unitize” their interests or be forced to unitize by an NMOCD order.⁷⁷ In the event that they cannot obtain voluntary unitization,⁷⁸ the Statutory Unitization Act authorizes any working interest owner (as opposed to a royalty interest owner) to apply to the NMOCD for an order for unit operation of a pool.⁷⁹ The NMOCD may order unitization if it finds, after proper notice and hearing, that unitization is necessary for EOR, that the operations described in the application will prevent waste, that additional recovery will exceed costs, that both working and royalty interest owners will be benefitted, and that recovered oil and/or gas will be allocated on a “fair, reasonable and equitable basis” among the interest owners.⁸⁰ The order allocates

the costs of unit operations among the various owners.⁸¹ The order becomes effective upon the written approval of any combination of interest owners who, by the order, will be required to pay 75% of the costs.⁸² In order to prevent a *de facto* veto power, at least two owners must join if either one *working* interest owner makes up that entire 75%, or if *any* interest owner will be required to pay more than 25%, but less than 50%.⁸³ If approval is not completed within six months, the NMOCD must revoke the order.⁸⁴ Unitization may expand the unit operator’s implied rights of surface to the unitized lands, but does not extend those rights to leased land outside of the production area.⁸⁵

The NMOCD also has regulatory authority over underground storage of natural gas for purposes of conservation, efficiency, and predictability in supply.⁸⁶ Natural gas may only be stored in strata or formations incapable of economic oil or gas production, that do not underly potash deposits, and that are otherwise “suitable,” and storage may not compromise the integrity of water resources.⁸⁷ Natural gas storage operators must apply to the NMOCD for storage approval and eminent domain authority,⁸⁸ and retain ownership of injected natural gas.⁸⁹ Natural Gas Storage facilities which serve interstate commerce are federally regulated by the FERC.

New Mexico law does not specifically address induced seismicity. However, NMOCD policy prohibits injection below certain geologic sequences and formations, and the NMOCD unofficially coordinates with the New Mexico Bureau of Geology and Mineral Resources to monitor seismic activity.⁹⁰ A recent peer review of the NMOCD states that, in light of the increased potential for induced seismicity in the Permian Basin due to higher EOR rates, the NMOCD should “evaluate” its own authority to regulate seismic-inducing activities and further develop its “monitoring and investigation capabilities.”⁹¹

⁶⁷ N.M. STAT. ANN. § 70-2-12 (West 2020).

⁶⁸ N.M. STAT. ANN. § 70-2-15 and 16 (West 2020).

⁶⁹ N.M. STAT. ANN. § 70-2-12(B)(14) (West 2020); *see also* New Mexico Oil Conservation Division Underground Injection Control Program Approval 47 Fed. Reg. 5412 (approved Feb. 5, 1982) (codified 40 C.F.R. § 147.1601).

⁷⁰ N.M. STAT. ANN. § 70-2-34(A) (West 2020).

⁷¹ N.M. STAT. ANN. § 70-2-14 (West 2020); N.M. CODE R.19.15.8.9(A) (West 2020).

⁷² N.M. CODE R. 19.15.26.8(A) and (B) (West 2020).

⁷³ *Id.*

⁷⁴ N.M. CODE R. 19.15.26.8 (West 2020).

⁷⁵ *Id.*

⁷⁶ N.M. STAT. ANN. § 70-2-12 (West 2020); *see also* Rutter & Wilbanks Corp. v. Oil Conservation Comm’n, 532 P.2d 582, 584 (N.M. 1975).

⁷⁷ N.M. STAT. ANN. § 70-2-17(C) (West 2020).

⁷⁸ N.M. STAT. ANN. § 70-7-6(a)(5) (West 2020).

⁷⁹ N.M. STAT. ANN. § 70-7-5 (West 2020).

⁸⁰ N.M. STAT. ANN. § 70-7-6 (West 2020).

⁸¹ N.M. STAT. ANN. § 70-7-7 (West 2020).

⁸² N.M. STAT. ANN. § 70-7-8 (West 2020).

⁸³ *Id.*

⁸⁴ *Id.*

⁸⁵ *Kysar v. Amoco Production Co.*, 135 N.M. 767 (N.M. 2004).

⁸⁶ N.M. STAT. ANN. § 70-6-1--8 (West 2020).

⁸⁷ N.M. STAT. ANN. § 70-6-5 (West 2020).

⁸⁸ *Id.*

⁸⁹ N.M. STAT. ANN. § 70-6-8 (West 2020).

⁹⁰ STATE OF NEW MEXICO CLASS II UIC PROGRAM PEER REVIEW, GROUND WATER PROTECTION COUNCIL, 12 (2020), <http://www.emnrd.state.nm.us/OCD/documents/NewMexicoPeerReviewFinalVersion1-8-2020.pdf>.

⁹¹ *Id.* at 5.

The State Land Office has concurrent jurisdiction with the NMOCD regarding the regulation of oil and gas leases of state land. In addition to NMOCD regulations, the State Land Office prescribes additional regulations and bonds to protect the state land.⁹²

Pipeline Regulation

The Pipeline Safety Bureau of the New Mexico Public Regulation Commission regulates and enforces the safety of oil and gas intrastate pipelines and facilities in New Mexico pursuant to both State and Federal pipeline safety regulations.⁹³ The Pipeline Safety Bureau also regulates CO₂ pipelines,⁹⁴ and CO₂ is likely included in the statutory definition of gas, as either a “natural gas” or “corrosive gas.”⁹⁵ The New Mexico Pipeline Safety Act requires each pipeline operator to file a yearly license, fee, and report containing the miles of both jurisdictional gathering and intrastate transmission in New Mexico.⁹⁶ The Pipeline Safety Bureau may inspect and investigate pipelines for safety compliance.⁹⁷

State Environmental Laws

The UIC program in New Mexico is administered by the New Mexico Water Quality Control Commission, the Environmental Improvement Division, and the NMOCD.⁹⁸ Class II wells are administered solely by the NMOCD.⁹⁹ Effective on March 7, 1982, the NMOCD was granted primacy over Class II wells in New Mexico.¹⁰⁰ Through Part 19 of its Code, the NMOCD ensures that EPA minimum standards for Class II wells are met.¹⁰¹

The New Mexico Environmental Improvement Act (NMEIA)¹⁰² created the New Mexico Environment Department (“NMED”), “to ensure an environment that confers the optimum health, safety, comfort and

economic and social well-being on its inhabitants.”¹⁰³ The NMED develops and enforces rules and regulations for water supply, liquid waste, and air quality management according to the Air Quality Control Act.¹⁰⁴ The NMEIA also established the Environmental Improvement Board¹⁰⁵ which created a PSD permitting program, which applies to any person “that emits or will emit regulated pollutants in an attainment or unclassified area.”¹⁰⁶ The PSD program defines CO₂ as one of the six gases that makes up the grouping of “greenhouse gas.”¹⁰⁷ The program provides that GHGs are not subject to regulation unless emissions exceed a certain threshold.¹⁰⁸ This threshold varies depending on whether the source is new or existing, or whether it is deemed a “major” source.¹⁰⁹ This PSD permitting program could apply to CO₂-EOR facilities, leading to increased costs for the operators.

Industrial Siting Requirements

New Mexico does not have a separate industrial siting board, agency, or commission. The NMOCD regulates siting of oil and gas operations,¹¹⁰ and specifically regulates the siting of oil and gas waste facilities to protect water sources.¹¹¹ The State Land Office also regulates siting on state public lands and has established procedures to protect the surface of the land.¹¹²

Local Regulation

Local governments, such as counties, may properly exercise some regulatory power over oil and gas operations within their jurisdictions. The New Mexico constitution grants municipalities home rule authority over all matters not “expressly denied by general law or charter.”¹¹³ The NMOGA does not expressly preempt local regulations. For example, in 2008, Santa Fe County enacted an ordinance that established a three-step process for seeking local approval for oil and gas operations, in addition to the NMOCD requirements.¹¹⁴ The ordinance reduced the number of wells allowed in the Galisteo Basin, located within Santa Fe County, to only 10% of

⁹² N.M. CODE R. 9-2-10 (West 2020).

⁹³ N.M. STAT. ANN. § 70-3-1 (West 2020); N.M. CODE R. 18.60.2.7(C) (West 2020).

⁹⁴ See PIPELINE SAFETY BUREAU, TRANSPORTATION – PIPELINE SAFETY, <http://www.nmprc.state.nm.us/transportation/pipeline-safety.html#gsc.tab=0> (last visited July 8, 2020).

⁹⁵ N.M. STAT. ANN. § 70-3-12 (West 2020).

⁹⁶ N.M. STAT. ANN. § 70-3-2 (West 2020); N.M. CODE R. 18.60.3.10 (West 2020).

⁹⁷ N.M. STAT. ANN. § 70-3-13 (West 2020)).

⁹⁸ See New Mexico Oil Conservation Division Underground Injection Control Program Approval 47 Fed. Reg. 5412 (approved Feb. 5, 1982) (codified 40 C.F.R. § 147.1601).

⁹⁹ 40 C.F.R. § 147.1600 (2020).

¹⁰⁰ *Id.*

¹⁰¹ See N.M. CODE R. 19-15-26-6 (West 2020); see also NEW MEXICO’S UNDERGROUND INJECTION CONTROL (UIC) PROGRAM: CLASS II WELL FACTS, OIL CONSERVATION DIVISION, <http://www.emnrd.state.nm.us/OCDDOCUMENTS/UICINJECTIONWELLBROCHURE.pdf> (last visited July 8, 2020).

¹⁰² N.M. STAT. ANN. § 74-1-1 (West 2020) (providing that “Chapter 74, Article 1 NMSA 1978 may be cited as the ‘Environmental Improvement Act’”).

¹⁰³ N.M. STAT. ANN. § 74-1-2 (West 2020).

¹⁰⁴ N.M. STAT. ANN. § 74-1-7 (West 2020); see also N.M. STAT. ANN. § 74-2-1 (West 2020) (providing that “Chapter 74, Article 2 NMSA 1978 may be cited as the ‘Air Quality Control Act’”).

¹⁰⁵ N.M. STAT. ANN. § 74-1-4 (West 2020).

¹⁰⁶ N.M. ADMIN CODE § 20.2.74 (West 2020).

¹⁰⁷ N.M. CODE R. § 20.2.74.7(Y) (West 2020).

¹⁰⁸ N.M. CODE R. § 20.2.74.7(AZ) (West 2020).

¹⁰⁹ *Id.*

¹¹⁰ N.M. STAT. ANN. § 70-2-12 (West 2020).

¹¹¹ N.M. CODE R. § 19-15-36 (West 2020).

¹¹² N.M. CODE R. § 9-2-100-66 (West 2020).

¹¹³ N.M. CONST., art. X § 6.

¹¹⁴ SANTA FE CTY., N.M., ORDINANCE 2008-19 (Dec. 9, 2008) § 8, https://www.santafecountynm.gov/userfiles/SFCOrdinance2008_19.pdf (last visited July 8, 2020).

those permitted by the NMOCD.¹¹⁵ Consistent with the concurrent jurisdiction allowed by the NMOGA, the ordinance states that it “is supplementary to, does not replace, enhances and is consistent with . . . federal and state statutes[.]”¹¹⁶ In response, the New Mexico Oil Conservation Commission, the NMOCD’s oversight board, enacted a special rule increasing NMOCD regulation in Santa Fe County and the Galisteo Basin, and clarifying that the special rule “does not relieve an operator of responsibility for complying with any other applicable federal, state or local statutes, rules or regulations or ordinances.”¹¹⁷ This rule allows Santa Fe County to continue to enforce its ordinance, without directly setting a precedent allowing other counties to follow suit.

Local regulation which conflicts with NMOCD regulation or entirely precludes development may be overturned. In 2007, Mora County enacted a zoning ordinance banning all oil and gas operations.¹¹⁸ This ordinance was overturned in the Federal District Court of New Mexico for unconstitutional overbreadth under the First Amendment to the U.S. Constitution,¹¹⁹ and for violation of the U.S. Constitution’s Supremacy Clause.¹²⁰ The Court also found that the ordinance violated state law by purporting to regulate activities on state owned land without statutory authority, and that the NMOGA impliedly preempted Mora County from “completely banning oil-and-gas production.”¹²¹ The Court also noted that “New Mexico state law does not impliedly preempt the entire oil-and-gas field” and that there is “room for concurrent regulation” by New Mexico counties.¹²² New Mexico counties may enact more and stricter regulations than those adopted by the NMOCD, but may not completely ban activities the state permits.

Tribal Lands

New Mexico has a substantial amount of tribal land within its borders, with 23 federally recognized tribes in the state.¹²³ Those 23 tribes are as follows: 19 Pueblo tribes, three Apache tribes, and a portion of the Navajo Nation.¹²⁴

The EPA retains primacy over UIC programs on tribal lands, except with respect to the Navajo Nation.¹²⁵ The Navajo Nation has primacy over Class II wells on its territory, and operators must comply with the Navajo Nation Statutes, Regulations and Resolution notebook dated October, 2008.¹²⁶ In addition, the Navajo Nation Clean Water Act imposes stricter water quality standards on sources that have “cultural value and use[.]”¹²⁷ Furthermore, the Navajo nation’s version of CERCLA explicitly includes petroleum within the definition of “hazardous substance,” while the federal version explicitly excludes it.¹²⁸ This causes any unauthorized spills or releases of petroleum on the Reservation to be subject to penalties and restrictions under the Navajo Nation version of CERCLA.¹²⁹ The Navajo Nation also has its own Air Quality Control Program, which entails a PSD permitting program similar to that of New Mexico and the Clean Air Act. Lastly, the Navajo Nation Oil and Gas Company (“NNOGC”) is responsible for the facilitation of oil and gas development on the Reservation and has a first right of refusal option on behalf of the Tribe for sunsetting leases on Tribal lands.¹³⁰

The BLM bears primary responsibility for permitting and inspection of oil and gas operations on tribal lands, as well as regulation enforcement.¹³¹ For leasing, however, the Navajo Nation Minerals and Land Departments are responsible for coordinating with the lessor to negotiate terms and conditions, as well as to draft the lease documents.¹³² Once a lease has been prepared, the Tribal Council and President are required to review and approve the lease, prior to the final review by the BIA.¹³³ CO₂-EOR and storage would therefore also be federally administered, except with respect to Class II wells located within the Navajo Nation. Our research did not reveal any tribal codes specifically relating to CO₂-EOR or geologic storage.

¹²⁵ 40 C.F.R. § 147.1603 (2020).

¹²⁶ See Navajo Nation; Underground Injection Control (UIC) Program Primacy Approval, 73 Fed. Reg. 65556 (approved Dec. 4, 2008) (codified at 40 C.F.R. § 147.1603).

¹²⁷ NAVAJO NATION CLEAN WATER ACT § 201.

¹²⁸ INTERMOUNTAIN OIL AND GAS BMP PROJECT, NAVAJO NATION LAWS, NAVAJO NATION COMPREHENSIVE ENVIRONMENTAL RESPONSE COMPENSATION AND LIABILITY ACT, <https://www.oilandgasbmps.org/laws/tribal/navajonation.php> (last visited July 23, 2020).

¹²⁹ *Id.*

¹³⁰ Navajo Nation Oil and Gas Company, Running Horse Pipeline, <https://www.nnogg.com/rhp/> (last visited July 23, 2020);

¹³¹ 12 U.S.C. 396a *et seq.* (2020); 25 U.S.C. Title 25, ch. 23, §§ 2101-08 (2020); 25 C.F.R. §§ 200-227.3 (2020).

¹³² Telephone interview with Steven L. Prince, Principal Petroleum Engineer, Navajo Nation Minerals Department – Oil & Gas (June 10, 2020).

¹³³ *Id.*

¹¹⁵ SANTA FE CTY., N.M., *supra* note 114, § 9.4.1.1.

¹¹⁶ SANTA FE CTY., N.M., *supra* note 114, § 4.

¹¹⁷ N.M. CODE R. § 19.15.39.9.(J)(9).

¹¹⁸ SWEPI, LP v. Mora Cty, 81 F.Supp 3d 1075, 1093, 94 (D.N.M. 2015).

¹¹⁹ *Id.* at 1187.

¹²⁰ *Id.* at 1173.

¹²¹ *Id.* at 1189-1203.

¹²² *Id.* at 1093, 96.

¹²³ NEW MEXICO INDIAN AFFAIRS DEPARTMENT, HISTORY, <https://www.iad.state.nm.us/about-us/history/> (last visited June 4, 2020).

¹²⁴ *Id.*

“The New Mexico Gathering Line Acquisition Act provides separate procedures and valuation requirements for the condemnation of gathering lines by mineral owners, operators, and lessees.”

Eminent Domain:

Eminent domain authority in New Mexico is both statutory and constitutional. Article 2, Section 20 of the state’s constitution provides that “[p]rivate property shall not be taken or damaged for public use without just compensation.”¹³⁴ The Eminent Domain Code (“EDC”) outlines the procedures involved in the condemnation of private property.¹³⁵ These procedures require reasonable and diligent efforts to acquire private property through negotiation, and an appraisal process if negotiations are unsuccessful.¹³⁶ The EDC provides that a condemnor has a pre-condemnation entry right for surveying and appraisal activities.¹³⁷ If property is sought for public use, the condemnor must file a petition with the court of the county in which the property is situated and, concurrently with this petition, may apply for an order for immediate possession of the property from the court.¹³⁸ The order will only be granted if the court determines that “the use for which the property sought to be condemned is a public use and that immediate possession is necessary.”¹³⁹

New Mexico has statutorily recognized eminent domain powers to acquire lands necessary for the purpose of constructing pipelines. A person, firm, association, or corporation may be granted eminent domain power to acquire “the necessary right-of-way for the purpose of conveyance of petroleum, natural gas, *carbon dioxide*

gas and the products derived therefrom”¹⁴⁰ Such rights-of-way “shall in all cases be so located as to do the least damage to private or public property consistent with proper use and economical construction.”¹⁴¹

The eminent domain power provided for in this statute is applicable to both “trunk lines” and “gathering lines,” though different standards apply to each.¹⁴² “Trunk lines” are statutorily defined as “the main transmission line which transports petroleum, natural gas, carbon dioxide gas and the products derived therefrom from a producing area to the area where... [it is] to be used.”¹⁴³ All other petroleum, natural gas, and carbon dioxide pipelines are defined as “gathering lines.”¹⁴⁴ While eminent domain rights for “trunk lines” are not limited, eminent domain rights for “gathering lines” have been limited only for “pipelines owned or operated by public utilities or their affiliates or interstate pipelines or to operators of pipelines whose rates are prescribed or whose operations are licensed by the state corporation commission [.]”¹⁴⁵

The New Mexico Gathering Line Acquisition Act provides separate procedures and valuation requirements for the condemnation of gathering lines by mineral owners, operators, and lessees.¹⁴⁶ Gathering line operators must seek to negotiate a voluntary agreement with affected property owners and may petition a court for approval of their plans only after engaging in such negotiations.¹⁴⁷ If an operator petitions the court, the court may approve the gathering line only if the path is not in dispute.¹⁴⁸ Otherwise, a hearing officer, approved by both parties and appointed by the court, will investigate the proposed gathering line and make a decision on the matter, including compensation and damages to be paid to the property owner.¹⁴⁹ New Mexico does not impose common carrier requirements on pipelines acquired using eminent domain, although it does allow the public regulation commission to set maximum rates common carriers may charge for oil transportation.¹⁵⁰

¹³⁴ N.M. CONST. art. 2, § 20.

¹³⁵ N.M. STAT. ANN. § 42A-1-1 (West 2020) (stating that “[s]ections 42A-1-1 through 42A-1-33 NMSA 1978 may be cited as the ‘Eminent Domain Code’”).

¹³⁶ See N.M. STAT. ANN. § 42A-1-4 (West 2020); see also N.M. STAT. ANN. § 42A-1-5(A) (West 2020).

¹³⁷ N.M. STAT. ANN. § 42A-1-8 (West 2020); see also N.M. STAT. ANN. § 42A-1-9 (West 2020) (providing the procedures required in obtaining a court order for entry to conduct suitability studies).

¹³⁸ N.M. STAT. ANN. § 42A-1-17 (West 2020) (stating the above proposition and providing the required contents of a petition).

¹³⁹ N.M. STAT. ANN. § 42A-1-22 (West 2020).

¹⁴⁰ N.M. STAT. ANN. § 70-3-5(A) (West 2020) (emphasis added).

¹⁴¹ *Id.*

¹⁴² N.M. STAT. ANN. § 70-3-5(B) (West 2020).

¹⁴³ *Id.*

¹⁴⁴ *Id.*

¹⁴⁵ *Id.*

¹⁴⁶ Gathering Line Land Acquisition, N.M. STAT. ANN. § 70-3A-1—7 (West 2020).

¹⁴⁷ N.M. STAT. ANN. § 70-3A-3 (West 2020).

¹⁴⁸ N.M. STAT. ANN. § 70-3A-4 (West 2020).

¹⁴⁹ *Id.*; N.M. STAT. ANN. § 70-3A-5 (West 2020).

¹⁵⁰ N.M. STAT. ANN. § 70-3-1 (West 2020).

Geologic CO₂ Storage Regulation and Incremental Storage:

New Mexico does not specifically regulate geologic or incremental CO₂ storage, and has not been granted primacy over Class VI sequestration wells.¹⁵¹ However, in its 2006 report, the New Mexico Climate Change Advisory Group (“NMCCAG”) recommended that the NMOCD be charged with the regulation and implementation of carbon capture and storage. The NMCCAG additionally recommended that New Mexico aim to capture, store, and/or reuse 7% of CO₂ “emissions from natural gas processing every year.”¹⁵²

New Mexico has not legislatively or judicially determined ownership and liability for injected CO₂. New Mexico has statutorily subscribed to the ownership theory of injection for purposes of natural gas storage.¹⁵³ We speculate that New Mexico courts could apply this model to CO₂ injection, especially since CO₂ has been defined as a natural gas in mineral reservations from grants of state trust land.¹⁵⁴

Liability for damage caused by injected CO₂ may arise from the common law tort of trespass. New Mexico recognizes a cause of action for subsurface trespass.¹⁵⁵ Thus, should injected CO₂ migrate from the intended injection formation into neighboring geologic formations, any potential liability will accrue to the injector/owner.



“Liability for damage caused by injected CO₂ may arise from the common law tort of trespass.”

¹⁵¹ 40 C.F.R. § 147.1600 and 1601 (2020).

¹⁵² NEW MEXICO CLIMATE CHANGE ADVISORY GROUP, FINAL REPORT, 5-13 (2006), <http://www.climatestrategies.us/library/library/view/949>.

¹⁵³ N.M. STAT. ANN. § 70-6-8 (West 2020).

¹⁵⁴ N.M. STAT. ANN. § 19-10-2 (West 2020).

¹⁵⁵ Snyder Ranches, Inc. v. Oil Conservation Comm’n of State of N.M., 798 P.2d 587, 590 (N.M. 1990); Hartman v. Texaco Inc., 937 P.2d 979, 983 (N.M. Ct. App. 1997).

NORTH DAKOTA

Executive Summary

North Dakota is one of two states with primacy over Class I-VI UIC wells. It has some of the most sophisticated and well-developed CO₂ development and storage laws in the country. The North Dakota Industrial Commission and Pipeline Authority have the authority and experience necessary to encourage development of an integrated storage and pipeline system to take advantage of North Dakota's potential CO₂ industry. Recent legislation aimed to clarify pore space rights and articulating a legislative preference for injection activities including CO₂-EOR and geologic storage, stripped pore space owners of many rights. This legislation is currently being challenged in district court.

Background:

North Dakota includes federal, state, fee, and tribal lands. The state is composed of 44,452,480 acres of land. Only 1,733,641 acres (3.9%) of surface lands are federally owned, although federal split estate lands comprise 4.5 million acres.¹ There are small pockets of federal ownership throughout the state, but the largest parcels are located in the western portion of the state.

North Dakota operates under a common law legal system. The state's district courts act as courts of general jurisdiction and the first avenue of appeals from many of the state's administrative agencies. The North Dakota Supreme Court has jurisdiction to hear appeals from the district courts. The state created a temporary court of appeals in 1987, but it exercises appellate or original jurisdiction only on cases that are assigned to it by the state supreme court.²

The North Dakota Industrial Commission bears primary regulatory responsibility for CO₂-EOR and CO₂ geologic storage, while the North Dakota Public Service Commission regulates CO₂ pipelines. Federally recognized Indian tribes also have some authority over CO₂-EOR operations on tribal lands.

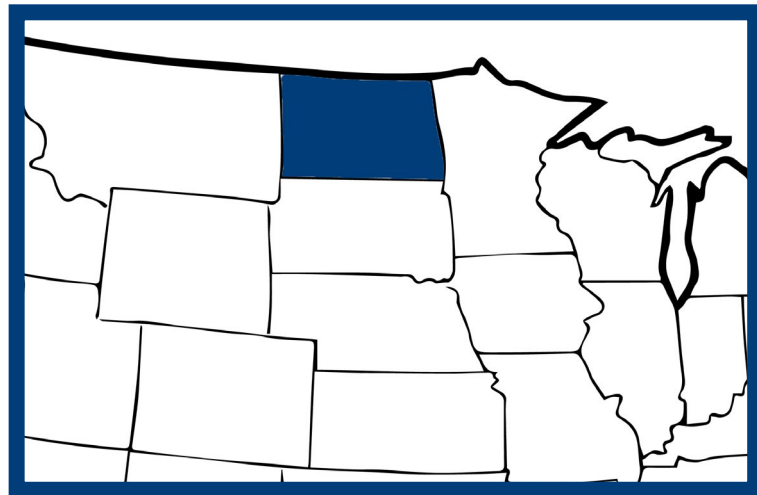
CO₂-EOR in North Dakota:

North Dakota does not currently have any operations that are injecting CO₂ for EOR purposes.³ However, there has been widespread speculation and study concerning the potential for incremental production

¹ Amy Mall, *BLM Fracking Rule Will Apply to More than 55 Million Acres of Private Land*, NAT. RES. DEF. COUNCIL (May 10, 2012), <https://www.nrdc.org/experts/amy-mall/blm-fracking-rule-will-apply-more-55-million-acres-private-land-see-maps>.

² N.D. CENT. CODE ANN. § 27-02.1-01 (West 2020).

³ Personal Communication with Matthew Wallace, Project Manager, Advanced Resources International, Inc. (June 3, 2020).



in North Dakota.⁴ Much of this speculation and study has centered around the Bakken Formation, which underlies the northwestern portion of the state within the Williston Basin.⁵ Denbury Resources Inc. is currently planning to begin CO₂-EOR operations in the Cedar Creek Anticline region, which lies within the Williston Basin and straddles the Montana-North Dakota border, in 2021 or 2022.⁶ This project will include a 105-mile extension of the Greencore CO₂ pipeline, which services the Bell Creek Field.⁷ A CO₂ capture project at the Great Plains Synfuels plant transports CO₂ via a 204-mile pipeline to the Weyburn CO₂-EOR project in Saskatchewan, Canada.⁸

A federally funded 2017-20 study by North Dakota CarbonSAFE found that commercial carbon capture and sequestration is technically viable in North Dakota.⁹ CarbonSAFE is currently seeking additional funding to research potential storage formations. Additionally, “Project Tundra” at the Milton R. Young Station, spearheaded by the Minnkota Power Cooperative, is planning to build the largest carbon capture facility in the world by capturing and storing 90% of emissions from the Young Station.¹⁰

⁴ *Id.*

⁵ ENERGY & ENVTL RESEARCH CTR., *Bakken CO₂ Storage and Enhanced Recovery Program*, <https://undeerc.org/bakken/Bakken-CO2-EOR-Storage-Program.aspx> (last visited July 6, 2020).

⁶ *Future Tertiary Operations*, DENBURY <https://www.denbury.com/operations/rocky-mountain-region/tertiary-operations/default.aspx> (last visited Sept. 14, 2020).

⁷ *Id.*

⁸ WEYBURN – MIDALE CO₂ PROJECTS, PLAINS CO₂ REDUCTION (PCOR) PARTNERSHIP, <https://undeerc.org/pcor/CO2SequestrationProjects/Weyburn.aspx#:~:text=Weyburn%E2%80%93Midale%20CO%202%20Project&text=Since%202000%2C%20industrial%2Dgrade%20CO,fired%20Boundary%20Dam%20Power%20Station> (last visited July 2, 2020).

⁹ PCOR PARTNERSHIP, NORTH DAKOTA CARBONSAFE, <https://undeerc.org/pcor/co2sequestrationprojects/NDCarbonSafe.aspx> (last visited July 7, 2020).

¹⁰ PROJECT TUNDRA, <https://www.projecttundrand.com/> (last visited July 7, 2020).

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

North Dakota courts interpret deeds “in the same manner as contracts.”¹¹ Pursuant to North Dakota statutes governing contract interpretation,¹² North Dakota courts are tasked with determining the intent of the parties from a contract’s language and the mutual intention of the parties. If a deed is unambiguous, Courts ascertain intent “from the four corners of the deed[.]”¹³ When multiple differing “rational arguments” can be made about a certain provision, courts may look to the “circumstances under which [the contract] was made to explain the [ambiguous] provision.”¹⁴

The North Dakota legislature has specified the extent of both grants and reservations of “mineral rights” in deeds, as well as leases of mineral rights.¹⁵ In the absence of specific exclusions or inclusions, a mineral grant or reservation includes “all minerals of any nature whatsoever,” except for gravel, clay, or scoria which remain a part of the surface estate.¹⁶ Leases, on the other hand, only include specifically named substances, with their compounds and byproducts.¹⁷ Use of the phrase “all other minerals,” or of a similar phrase, does not increase the scope of a lease to encompass more than the specifically named substances.¹⁸ Oil and gas are generally classified with the mineral estate.¹⁹ While the statutes do not specifically mention CO₂, North Dakota’s broad definition of minerals would likely include CO₂ in a mineral conveyance; however, because North Dakota statutes provide that grants of minerals in oil and gas leases are construed only to include other “hydrocarbons,” CO₂ would be excluded as a non-hydrocarbon gas.

The North Dakota Industrial Commission (“NDIC”) is statutorily authorized to regulate conflicts between competing mineral interests involving production

of subsurface minerals,²⁰ including coal, oil, and gas.²¹ In the absence of voluntary agreement, the NDIC may resolve the conflict in a manner that allows greatest recovery of all involved minerals.²²

Split Estates

North Dakota imposes an implied servitude on the surface estate for the benefit of the mineral estate. The common law implied servitude of the surface estate obligates the mineral developer to have “due regard for the rights of the surface owner” and to “exercise [a] degree of care and use which is a just consideration for the rights of the surface owner[.]”²³ North Dakota’s courts adopted the accommodation doctrine with respect to these limitations. This doctrine allows mineral developers to access and use the surface as is “reasonably necessary to explore, develop, and transport the minerals.”²⁴

The scope of the common law implied easement has been limited by two North Dakota legislative acts: the Surface Owner Protection Act (“SOPA”)²⁵ and the Oil and Gas Production Compensation Act (“OGPDCA”).²⁶ The SOPA provides “the maximum amount of constitutionally permissible protection to surface owners from the undesirable effects of development, without their consent, of minerals underlying their surfaces.”²⁷ Under the SOPA, a mineral developer must give notice of operations to the surface owner,²⁸ attempt to gain the consent of the surface owner before commencing operations,²⁹ make annual payments to the surface owner for damage to agricultural production,³⁰ and cover the cost of surface reclamation.³¹ If the mineral developer cannot obtain consent from the surface owner, a court may allow the mineral operations to proceed if it finds that the surface owner will be “adequately compensated[.]”³² The OGPDCA places additional compensation requirements

²⁰ N.D. CENT. CODE ANN. § 38-15-03 (West 2020).

²¹ *Id.*

²² *Id.*; see also § 38-15-01.

²³ *Hunt Oil Co. v. Kerbaugh*, 283 N.W.2d 131, 135-46 (N.D. 1979); see also *Krentz v. XTO Energy, Inc.* 890 N.W.2d 222, 237 (N.D. 2017).

²⁴ *Hunt Oil Co. v. Kerbaugh*, 283 N.W.2d 131, 135-36 (N.D. 1979).

²⁵ Surface Owner Protection Act, § 38-18-01 to 08 (West 2020).

²⁶ Oil and Gas Production Damage Compensation, § 38-11.1-01 to 10 (West 2020).

²⁷ N.D. CENT. CODE ANN. § 38-18-01 (West 2020).

²⁸ N.D. CENT. CODE ANN. § 38-18-06 (West 2020). Elsewhere in the North Dakota Centennial Code, the mineral developer is required to give the surface owner 7 days’ notice before entering for pre-drilling operations, ND Cent. Code § 38-11.1-07 (West 2020), and 20 days’ notice before any drilling operations. ND Cent. Code § 38-11.2-03 (West 2020).

²⁹ § 38-18-06.

³⁰ N.D. CENT. CODE ANN. § 38-18-07 (West 2020).

³¹ N.D. CENT. CODE ANN. § 38-18-08 (West 2020).

³² N.D. CENT. CODE ANN. § 38-18-06 (West 2020).

¹¹ *Carkuff v. Balmer*, 795 N.W.2d 303, 306 (N.D. 2011).

¹² See N.D. CENT. CODE ANN. § 9-07-01 et seq (West 2020).

¹³ *Carkuff*, 795 N.W.2d at 306.

¹⁴ *Mueller v. Stangeland*, 340 N.W.2d 450, 453-454 (N.D. 1983);

N.D. CENT. CODE ANN. § 9-07-12 (West 2020).

¹⁵ N.D. CENT. CODE ANN. § 47-10-24 and 25 (West 2020).

¹⁶ N.D. CENT. CODE ANN. § 47-10-24 and 25 (West 2020).

¹⁷ N.D. CENT. CODE ANN. § 47-10-24 (West 2020).

¹⁸ *Id.*

¹⁹ *Vogel v. Marathon Oil Co.*, 879 N.W.2d 471, 480 (ND 2016); *State ex rel. Rausch v. Amerada Petroleum Corp.*, 49 N.W.2d 141 17 (N.D. 1951).

on oil and gas developers. Before beginning operations, an oil and gas developer must either make an “offer of settlement” to, or reach a compensation agreement with, the surface owner.³³ The developer may commence work even if the offer of settlement is rejected or no agreement is reached. However, if the surface owner notifies the developer of any damages,³⁴ the developer is obligated to compensate the surface owner for any devaluation of land or improvements caused by the oil and gas operations, as well as lost use of and access to the land.³⁵ In the absence of a compensation agreement, the surface owner may “bring an action for compensation” against the developer.³⁶

Pore Space Ownership

North Dakota statutes define pore space as “a cavity or void, naturally or artificially created, in a subsurface sedimentary stratum.”³⁷ North Dakota legislatively declared in 2009 that ownership of pore space “is vested in the owner of the overlying surface estate.”³⁸ Any conveyance of the surface estate also conveys the pore space,³⁹ and pore space may not be severed from the surface.⁴⁰ The statutory provision prohibiting severance of the pore space does not apply retroactively.⁴¹

The North Dakota legislature and courts are addressing the extent to which recognition of surface rights in pore space creates remedies in other damage compensation statutes. In 2014, in *Fisher v. Continental Resources*, a North Dakota district court concluded that a unit operator had an implied right to use the pore space for disposal but that the surface owner had a right to bring a claim for compensation under the OGPDCA.⁴² Three years later, in *Mosser v. Denbury Resources, Inc.*, the North Dakota Supreme Court held that under the OGPDCA “a surface owner may be entitled to compensation . . . for a mineral developer’s use of the surface owner’s subsurface pore space for disposal of saltwater”⁴³ notwithstanding whether the surface owner is currently or in the near future planning to use the pore space.⁴⁴ Moreover, the *Mosser* court found that the surface owner does not have to prove any damage beyond “mere occupancy or loss of access to the pore space[.]”⁴⁵

³³ N.D. CENT. CODE ANN. § 38-11.1-08 (West 2020).

³⁴ N.D. CENT. CODE ANN. § 38-11.1-07 (West 2020).

³⁵ N.D. CENT. CODE ANN. § 38-11.1-04 (West 2020).

³⁶ N.D. CENT. CODE ANN. § 38-11.1-09 (West 2020).

³⁷ N.D. CENT. CODE ANN. § 47-31-02 (West 2020).

³⁸ N.D. CENT. CODE ANN. § 47-31-03 (West 2020).

³⁹ N.D. CENT. CODE ANN. § 47-31-04 (West 2020).

⁴⁰ N.D. CENT. CODE ANN. § 47-31-05 (West 2020).

⁴¹ N.D. CENT. CODE ANN. § 47-31-07 (West 2020).

⁴² *Fisher v. Continental Res., Inc.*, 49 F. Supp. 3d 637, 648 (D.N.D. 2014).

⁴³ *Mosser v. Denbury Res., Inc.*, 898 N.W.2d 406 (N.D. 2017).

⁴⁴ *Id.* at 415-17.

⁴⁵ *Id.*

In 2019, legislation redefined “land” as used in the OGPDCA to specifically exclude pore space.⁴⁶ This effectively removed the statutory protection extended to pore space by *Fisher* and *Mosser*. The legislation also entitles mineral developers to use pore space for waste disposal purposes or oil and gas recovery processes without liability for “trespass, nuisance or other tort[.]”⁴⁷ removing common law protections previously afforded to pore space owners. Finally, the legislation includes a catch-all provision which states that “any other provision of law may not be construed to entitle the owner of [pore space] to prohibit or demand payment for the use of the [pore space.]”⁴⁸ These provisions are currently facing legal challenge from the Northwest Landowners Association.⁴⁹

Water Rights

The Constitution of North Dakota states that all “flowing streams and natural watercourses [are to] remain the property of the state for mining, irrigation, and manufacturing purposes.”⁵⁰ North Dakota has legislatively declared that all surface waters, “excluding diffused surface water,” and all groundwaters “in defined subterranean channel[s] or . . . diffused percolating [groundwaters]” are subject to appropriation only for beneficial use.⁵¹

Before using any water, a person must apply for a permit from the state engineer.⁵² The North Dakota Centennial Code provides that “[p]riority in time shall give the superior water right.”⁵³ However, when a water source “is insufficient to supply all applicants,” preference is allocated in the following order: domestic uses, municipal uses, livestock uses, irrigation uses, industrial uses, and finally recreational uses.⁵⁴ Permits may only be assigned or applied to a different use with the approval of the state engineer.⁵⁵ Water permits may be cancelled by the state engineer if the appropriator fails to beneficially use the water or ceases use, for reasons other than unavailability of water, for a period of three successive years.⁵⁶

⁴⁶ N.D. CENT. CODE ANN. § 38-11.1-03 (West 2020).

⁴⁷ N.D. CENT. CODE ANN. § 47-31-09 (West 2020).

⁴⁸ N.D. CENT. CODE ANN. § 38-08-25(5) (West 2020).

⁴⁹ Complaint, *Nw. Landowners Ass’n v. North Dakota*, No. 05-2019-CV-00085 (N.E.N.D. Jul. 29, 2019).

⁵⁰ N.D. CONST. art. XI, § 3.

⁵¹ N.D. CENT. CODE ANN. § 61-01-01 (West 2020); *see also* N.D.

CENT. CODE ANN. § 61-04-01.2 (West 2020) (providing that water rights may be obtained only for beneficial uses, and “beneficial use shall be the basis, the measure, and the limit of the right to the use of water”).

⁵² N.D. CENT. CODE ANN. § 61-04-02 (West 2020).

⁵³ N.D. CENT. CODE ANN. § 61-04-06.3 (West 2020).

⁵⁴ N.D. CENT. CODE ANN. § 61-04-06.1 (West 2020).

⁵⁵ N.D. CENT. CODE ANN. § 61-04-15 and 15.4 (West 2020).

⁵⁶ N.D. CENT. CODE ANN. § 61-04-23 (West 2020).

North Dakota allows the “United States, or any person, corporation, limited liability company, or association” to exercise eminent domain powers for public, beneficial uses of water.⁵⁷ Water resource districts are also authorized by statute to acquire “any rights, titles, interests, estates, or easements necessary . . . to carry out [their duties].”⁵⁸ North Dakota statutes authorize a water resource district to utilize a “quick take” for the purpose of a state or federal funded project.⁵⁹

Lithium Ownership and Extraction

North Dakota’s statutes define lithium as a subsurface mineral subject to regulation pursuant to Title 38.⁶⁰ The NDIC has authority to regulate its exploration, development, and production.⁶¹ Subsurface mineral developers, including lithium developers, must apply for a permit from the director of mineral resources in accordance with NDIC rules.⁶² Our research did not reveal any past or present production of lithium in North Dakota, although oilfield brine, from which lithium can be produced, is present in the Devonian formation in North Dakota.⁶³

Classification of CO₂: Commodity

North Dakota has statutorily recognized that “[c]arbon dioxide is a potentially valuable commodity, and increasing its availability is important for . . . enhanced recovery of oil, gas, and other minerals.”⁶⁴ CO₂ is also included in the definition of “energy-related

commodities[.]”⁶⁵ The state also recognizes that “[i]t is within the public interest” to use CO₂ to enable “the greatest possible economic recovery of oil and gas.”⁶⁶ To this end, the state exempts “sales of tangible personal property used to construct or expand a system used to . . . inject CO₂ for” EOR or sequestration.⁶⁷

North Dakota statutes provide that “carbon dioxide stored, and which remains in storage under a commission permit, is not a pollutant nor does it constitute a nuisance.”⁶⁸ Additionally, the North Dakota Department of Environmental Quality (“NDDEQ”) Air Quality Control program, explicitly excludes greenhouse gases from its definition of regulated pollutants.⁶⁹

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The NDIC regulates the drilling, producing, plugging, spacing, and chemical treatment of oil and gas wells, as well as operations to increase oil and gas recovery, saltwater (or produced water) disposal, and underground oil and gas storage.⁷⁰ Although North Dakota has had unitization laws for much longer, in 2019 the North Dakota legislature specifically declared a public interest in encouraging enhanced recovery operations, including CO₂-EOR projects.⁷¹ Oil and gas operators, including enhanced recovery operations, must comply with North Dakota’s conservation regulations prior to commencing operations. These include, without limitation, requirements for permitting, setbacks from occupied dwellings, and notice to residential owners.⁷² North Dakota’s conservation laws prohibit waste of oil and gas.⁷³

The NDIC may combine separately owned lands through pooling or unitization. The NDIC has authority to create spacing units for any pool to prevent waste and protect correlative rights.⁷⁴ When a spacing unit encompasses separately owned tracts of lands, the owners may voluntarily pool their interests.⁷⁵ In the absence of voluntary pooling, the NDIC may order pooling in a spacing unit at the application of any interested person,

“North Dakota’s statutes define lithium as a subsurface mineral subject to regulation pursuant to Title 38.”

⁵⁷ N.D. CENT. CODE ANN. § 61-01-04 (West 2020).

⁵⁸ N.D. CENT. CODE ANN. § 61-16.1-09 (West 2020).

⁵⁹ *Id.*

⁶⁰ N.D. CENT. CODE ANN. § 38-12-01(7) (West 2020).

⁶¹ N.D. CENT. CODE ANN. § 38-12-02 (West 2020).

⁶² N.D. CENT. CODE ANN. § 38-12-03 (West 2020).

⁶³ LAURENCE KAVANAGH ET AL., GLOBAL LITHIUM SOURCES – INDUSTRIAL USE AND FUTURE IN THE ELECTRIC VEHICLE INDUSTRY: A REVIEW, MDPI (2018).

⁶⁴ N.D. CENT. CODE ANN. § 38-08-25(2) (West 2020).

⁶⁵ N.D. CENT. CODE ANN. § 54-17.7-02(3) (West 2020).

⁶⁶ § 38-08-25(3).

⁶⁷ N.D. CENT. CODE ANN. § 57-39.2-04.14 (West 2020) (stating the above proposition and stating that a certificate must be obtained from the tax commissioner to receive the exemption).

⁶⁸ N.D. CENT. CODE ANN. § 38-22-12(1) (West 2020).

⁶⁹ N.D. ADMIN. CODE 33.1-15-15-01.2 (2020).

⁷⁰ N.D. CENT. CODE ANN. § 38-08-04 (West 2020).

⁷¹ N.D. CENT. CODE ANN. § 38-08-25(1) (West 2020).

⁷² *Id.*

⁷³ N.D. CENT. CODE ANN. § 38-08-03 (West 2020).

⁷⁴ N.D. CENT. CODE ANN. § 38-08-07 (West 2020).

⁷⁵ N.D. CENT. CODE ANN. § 38-08-08 (West 2020).

after notice and hearing.⁷⁶ Any such order must permit each owner to recover their “just and equitable share.”⁷⁷ Separate owners may also agree to unitize their interests in a field or pool if the agreement protects correlative rights, prevents waste, and is approved by the NDIC. A voluntary unitization agreement “bind[s] only the persons who execute them,” as well as their successors.⁷⁸ The NDIC may also order unitization upon approval or ratification of the interest owners of the field or pool who will be required, by the order, to pay more than 55% of the costs of unit operation, and the owners of more than 55% of the royalty interests.⁷⁹

To minimize induced seismicity, NDIC rules prohibit injection into formations with “open faults or fractures,”⁸⁰ and NDIC policy generally requires that disposal injection wells be located a half-mile below underground drinking water sources and one to two miles above the basement rock.⁸¹ Additionally, the NDIC requires that any produced saltwater be “processed, stored, and disposed of without pollution of freshwater supplies.”⁸²

The NDIC regulates “underground storage and retrieval of nonhydrocarbons,”⁸³ defined to “include compressed air, nitrogen, and other gases and liquids not otherwise regulated.”⁸⁴ Nonhydrocarbons may be stored in “a drilled, bored, or excavated device or installation providing for subsurface emplacement and recovery[.]”⁸⁵ Storage operations may not commence until the NDIC issues a permit after proper notice and hearing.⁸⁶ The NDIC will deny a permit if it finds that “the facility or activity poses a threat to ground or surface waters or the environment.”⁸⁷

Pipeline Regulation

The North Dakota Public Service Commission (“NDPSC”) is authorized to “establish and enforce minimum safety standards for the design, construction, and operation of gas distribution facilities and intrastate pipeline facilities used for the distribution and intrastate transportation of gas, liquified natural gas, or hazardous

liquids[.]”⁸⁸ The NDPSC’s rules may not, however, “be more stringent than the corresponding federal regulation applicable to interstate pipelines and related facilities.”⁸⁹ The Federal Energy Regulatory Commission regulates natural gas storage facilities which serve interstate commerce.⁹⁰

In 2007, North Dakota created the Pipeline Authority (“Authority”) under the governance of the NDIC⁹¹ “to support the production, transportation, and utilization of North Dakota energy-related commodities.”⁹² The Authority is authorized, among other things, to provide financial assistance to pipeline operators, to acquire or sell “interest[s] in . . . any pipeline system[s,]” and “enter contracts to construct, maintain, and operate pipeline facilities.”⁹³ Before gaining an ownership interest in a pipeline system, the Authority must “develop a plan identifying the public purposes of the authority’s ownership” and conditions for divestiture of that ownership.⁹⁴ The Authority must give private parties notice and opportunity to construct any necessary pipelines before the Authority may begin construction on its own.⁹⁵ Pipelines owned by the Authority are exempt from NDPSC rules, but the Authority is required to “consult with the NDPSC” to ensure that rates charged by the Authority are “just and reasonable.”⁹⁶

State Environmental Laws

North Dakota has primacy over all UIC wells.⁹⁷ The NDDEQ has primary enforcement authority over Class I, III, IV, and V wells.⁹⁸ Class II and VI wells are regulated by the NDIC.⁹⁹ The NDIC prohibits any underground injection that contaminates an underground source of drinking water.¹⁰⁰ Certain aquifers are exempt from this prohibition if they “cannot now and will not in the future serve as a source of drinking water” for reasons such as hydrocarbon or geothermal energy production or total dissolved solids in excess of that considered reasonable for public water system supply.¹⁰¹

⁷⁶ *Id.*

⁷⁷ *Id.*

⁷⁸ N.D. CENT. CODE ANN. § 38-08-09 (West 2020).

⁷⁹ N.D. CENT. CODE ANN. § 38-08-09.5 (West 2020).

⁸⁰ N.D. ADMIN. CODE 43-02-05-05 (2020); *see also* NORTH DAKOTA STATE GOVERNMENT, UNDERGROUND INJECTION CONTROL PROGRAM FREQUENTLY ASKED QUESTIONS, <https://www.dmr.nd.gov/oilgas/undergroundfaq.asp> (last visited July 6, 2020).

⁸¹ *Id.*

⁸² N.D. ADMIN. CODE 43-02-03-53 (2020).

⁸³ N.D. CENT. CODE ANN. § 38-24-02 (West 2020).

⁸⁴ N.D. CENT. CODE ANN. § 38-24-01 (West 2020).

⁸⁵ *Id.*

⁸⁶ N.D. CENT. CODE ANN. § 38-24-03 (West 2020).

⁸⁷ N.D. CENT. CODE ANN. § 38-24-04 (West 2020).

⁸⁸ N.D. CENT. CODE ANN. § 49-02-01.2 (West 2020).

⁸⁹ *Id.*

⁹⁰ 15 U.S.C.A. § 717f (West 2020).

⁹¹ *See* N.D. CENT. CODE ANN. § 54-17.7-01 (West 2020); *see also* N.D. CENT. CODE ANN. § 54-17.7-03 (West 2020) (stating the Pipeline Authority’s purpose).

⁹² N.D. CENT. CODE ANN. § 54-17.7-03 (West 2020).

⁹³ *See* N.D. CENT. CODE ANN. § 54-17.7-04 (West 2020).

⁹⁴ N.D. CENT. CODE ANN. § 54-17.7-10 (West 2020).

⁹⁵ N.D. CENT. CODE ANN. § 54-17.7-05(1) (West 2020).

⁹⁶ N.D. CENT. CODE ANN. § 54-17.7-08 (West 2020).

⁹⁷ 40 C.F.R. § 147.1750 (2020); 40 C.F.R. § 147.1751 (2020).

⁹⁸ 40 C.F.R. § 147.1751 (2020).

⁹⁹ *Id.*; 40 C.F.R. § 147.1750 (2020).

¹⁰⁰ N.D. ADMIN. CODE 43-02-05-02 (2020).

¹⁰¹ N.D. ADMIN. CODE 43-02-05-03 (2020) (stating the above proposition, and providing that an aquifer may be considered incapable of serving as a drinking water source if it is situated at a depth or location, or is so contaminated, that recovery is rendered economically or technologically impractical).

The Oil and Gas Research Council (“OGRC”) is tasked with “promot[ing] environmentally sound exploration and production methods and technologies, to develop [North Dakota’s] oil and gas resources . . . and to promote . . . enhancement of the environment”¹⁰² The OGRC is operated, managed, and controlled by the NDIC.¹⁰³

Industrial Siting Requirements

The NDPSA administers the North Dakota Energy Conversion and Transmission Facility Siting Act.¹⁰⁴ This act regulates, among other things, “gas or liquid conversion facility[ies.]”¹⁰⁵ defined as “a gas or liquid transmission line and associated facilities designed for or capable of transporting coal, gas, liquid hydrocarbons, liquid hydrocarbon products, or carbon dioxide.”¹⁰⁶ A transmission facility operator may not begin construction without first obtaining “a certificate of site compatibility or a route permit” from the NDPSA, and construction and operation must be “in conformity with the certificate or permit[.]”¹⁰⁷ If an operator fails to conform with the terms and conditions of a permit, the NDPSA may revoke it.¹⁰⁸

Local Regulation

North Dakota’s Constitution allows both cities and counties to establish home rule.¹⁰⁹ When a city passes a home rule charter, the charter, and ordinances under it, “supersede within the territorial limits and other jurisdiction of the city any law of the state in conflict with the charter and ordinances[.]”¹¹⁰ This grant is not limitless for either cities or counties, but only applies to certain powers enumerated by the legislature.¹¹¹ Although local governments are statutorily permitted to enforce zoning ordinances,¹¹² local regulation of oil and gas operations and facilities is preempted by the state legislature.¹¹³

¹⁰² N.D. CENT. CODE ANN. § 54-17.6-02 (West 2020).

¹⁰³ N.D. CENT. CODE ANN. § 54-17.6-03 (West 2020).

¹⁰⁴ Energy Conversion and Transmission Facility Siting Act, N.D. CENT. CODE ANN. § 49-22-01 to 24 (West 2020); *see also* Energy Conversion and Transmission Facilities, N.D. CENT. CODE ANN. § 49-22.1-01 to 22 (West 2020).

¹⁰⁵ Energy Conversion and Transmission Facilities, *supra* note 104.

¹⁰⁶ N.D. CENT. CODE ANN. § 49-22.1-01(7) (West 2020).

¹⁰⁷ N.D. CENT. CODE ANN. § 49-22.1-04 (West 2020).

¹⁰⁸ N.D. CENT. CODE ANN. § 49-22.1-19 (West 2020).

¹⁰⁹ N.D. CONST. art. VII § 6.

¹¹⁰ N.D. CENT. CODE ANN. § 40-05.1-05 (West 2020).

¹¹¹ *Sauby v. City of Fargo*, 747 N.W.2d 65, 68 (N.D. 2008).

¹¹² *See* N.D. CENT. CODE ANN. § 11-33-01 *et. seq.* (West 2020).

¹¹³ *See* *Envtl. Driven Sols., LLC v. Dunn Cty.*, 890 N.W.2d 841, 846 (N.D. 2019).

Tribal Lands

North Dakota encompasses at least a portion of five federally recognized Tribes and one Indian community.¹¹⁴ The EPA is directly responsible for implementing the UIC programs on the reservations of the five federally recognized Tribes within the state, while the BIA regulates leasing of tribal oil and gas interests.¹¹⁵ To help support state and federal agencies in their assistance of these Tribes, the state statutorily created the Indian Affairs Commission in 2009.¹¹⁶

The Three Affiliated Tribes of the Fort Berthold Indian Reservation—Mandan, Hidatsa and Arikara Nation—have adopted standardized rates, at a minimum of \$2000/acre, for right-of-way pipeline easements on the Reservation.¹¹⁷ Additionally, the Tribes require that a right-of-way applicant submit a specific “MHA Nation Application for Right of Way and Use of Rights-of-Way” to the MHA Nation Energy Division or the Natural Resource Department.¹¹⁸

The Turtle Mountain Band of Chippewa has imposed an oil and gas severance tax for oil and gas and associated liquid products that are severed from the Tribe’s territory, but explicitly exempts CO₂ from this tax.¹¹⁹ The Tribe has also established the Tribal Utility Commission, which has jurisdiction over pipeline utilities engaged in the transportation of oil, gas, coal, and water.¹²⁰ This commission is empowered to, *inter alia*, promulgate rules, investigate the methods and practices of pipeline utilities, and require pipeline utilities to conform with rules promulgated by the commission and Tribal laws.¹²¹

¹¹⁴ N.D. INDIAN AFFAIRS COMMISSION, TRIBAL NATIONS, <https://www.indianaffairs.nd.gov/tribal-nations> (last visited June 30, 2020).

¹¹⁵ 25 C.F.R. §§ 211.1 to 212.58 (2020).

¹¹⁶ N.D. CENT. CODE ANN. § 54-36-03 (West 2020).

¹¹⁷ RESOLUTION OF THE GOVERNING BODY OF THE THREE AFFILIATED TRIBES OF THE FORT BERTHOLD, Resolution No. 13-109-VJB, <https://static1.squarespace.com/static/5a5fab0832601e33d9f68fde/t/5b86aad90e2e729f459d31cb/1535552220253/Resolution+No+13-109-VJB+Establishment+of+the+TAT+Standardized+Minimum+Rates.pdf> (last visited June 30, 2020).

¹¹⁸ RESOLUTION OF THE GOVERNING BODY OF THE THREE AFFILIATED TRIBES OF THE FORT BERTHOLD, Resolution No. 15-045-LKH, <https://static1.squarespace.com/static/5a5fab0832601e33d9f68fde/t/5b86aad64fa51a10803a371d/1535552013889/Resolution+No+15-045-LKH+Establishing+a+Procedure+for+the+Approval+of+Leases%2C+Rights+of+Way%2C+Setback+Variances+and+Permissions+to+Survey+on+Tribal+Lan.pdf>

¹¹⁹ TURTLE MOUNTAIN TRIBAL CODE § 47.0201 (2014), <https://tmchip-pewa.com/wp-content/uploads/Title-47.gas-severance-code.pdf>.

¹²⁰ TURTLE MOUNTAIN TRIBAL CODE § 21.0401(1) (2012), <https://tm-chippewa.com/wp-content/uploads/TITLE-21-Utility-Code.pdf>.

¹²¹ TURTLE MOUNTAIN TRIBAL CODE § 21.0401(2) (2012), <https://tm-chippewa.com/wp-content/uploads/TITLE-21-Utility-Code.pdf>.

The Spirit Lake Tribe established the Tribal Utility Commission (“TUC”), with jurisdiction over, *inter alia*, “[p]ipeline utilities engaged in the transportation of gas, oil, coal, and water[.]”¹²² The TUC has investigatory and regulatory powers, including the ability to compel compliance with the laws of the Tribe and any rules or regulations promulgated by the TUC.¹²³ In addition, the TUC has the power, after notice and hearing, to establish, adjust, and enforce rates on all pipeline utilities within the Reservation.¹²⁴

The BLM has primary responsibility for oil and gas regulation on the remaining reservations.¹²⁵

Eminent Domain:

The North Dakota Constitution states that private property may not be taken for public use without payment of “just compensation.”¹²⁶ A 2006 constitutional amendment states that the “public benefits of economic development” do not constitute a public use, and provides that private entities may not condemn private property unless “necessary for conducting a common carrier or utility business.”¹²⁷ The North Dakota legislature included “oil, gas, coal and carbon dioxide pipelines[.]” as well as water transportation projects, in its list of public uses that may exercise eminent domain authority.¹²⁸ North Dakota has not specifically enumerated pore space for geologic storage as a public use.

To exercise eminent domain, a condemner must demonstrate that the taking is legal and necessary¹²⁹ and that the condemner attempted to negotiate with the property owner for its use.¹³⁰ Before property is condemned, an agent for the condemner may enter onto the land to survey it to determine the location that will serve “the greatest public benefit and the least private injury[.]”¹³¹ The statute specifically prevents the state from using eminent domain to “obtain any rights or interest in or to the oil, gas, or fluid minerals on or underlying any estate[.]”¹³²

Common pipeline carriers are authorized by statute to exercise eminent domain power.¹³³ North Dakota defines “common pipeline carriers” as “[a]ny person owning, operating, or managing any pipeline or any part of any pipeline within this state for the transportation of crude petroleum, gas, coal, or carbon dioxide to or for the public for hire[.]”¹³⁴ Subject to certain limitations, common pipeline carriers may secure a right-of-way across any public stream or highway “to lay, maintain, and operate pipelines[.]”¹³⁵ A pipeline carrier that has filed acceptance of the state’s common carrier provisions with the NDPSD may exercise eminent domain to “enter upon and condemn the land, right-of-way, easements, and property of any person necessary for the construction, maintenance, or authorization of its pipeline.”¹³⁶

Geologic CO₂ Storage Regulation and Incremental Storage:

North Dakota legislatively governs geologic CO₂ storage.¹³⁷ The NDIC is authorized to unitize pore space to allow efficient storage operations,¹³⁸ to grant, amend, and revoke CO₂ storage permits,¹³⁹ and to collect fees to fund these activities.¹⁴⁰

North Dakota statutes allow storage reservoirs to be operated as a unit for CO₂ storage purposes. A CO₂ storage reservoir is defined as “a subsurface sedimentary stratum, formation, aquifer, cavity, or void, whether natural or artificially created, including oil and gas reservoirs, saline formations, and coal seams suitable for or capable of being made suitable for injecting and storing carbon dioxide.”¹⁴¹ Prior to using a reservoir for storage operations, an operator must negotiate in good faith with all of the owners of a proposed storage reservoir’s pore space for voluntary unit operation.¹⁴² Consent of the owners of at least 60% of the pore space is required to begin operations.¹⁴³ The NDIC may unitize all of the reservoir’s pore space by ordering that the pore space of any non-consenting owners be included in the storage reservoir,¹⁴⁴ although the operator must make adequate compensation to the non-consenting owners.¹⁴⁵

¹²² SPIRIT LAKE TRIBE LAW AND ORDER CODE § 17-4-101(1) (1992), http://spiritlakenation.com/data/upfiles/media/Title_17_Uilities.pdf.

¹²³ SPIRIT LAKE TRIBE LAW AND ORDER CODE § 17-4-101(2) (1992), http://spiritlakenation.com/data/upfiles/media/Title_17_Uilities.pdf.

¹²⁴ SPIRIT LAKE TRIBE LAW AND ORDER CODE § 17-4-101(4) (1992), http://spiritlakenation.com/data/upfiles/media/Title_17_Uilities.pdf.

¹²⁵ 25 U.S.C. 396a *et seq.* (2020); Development of Tribal Mineral Resources, 25 U.S.C. § 2101 to 08 (2020); 25 C.F.R. §§ 200 to 227.3 (2020).

¹²⁶ N.D. CONST. art. I, § 16.

¹²⁷ *Id.*

¹²⁸ N.D. CENT. CODE ANN. § 32-15-02(3) and (10) (West 2020).

¹²⁹ N.D. CENT. CODE ANN. § 32-15-05 (West 2020).

¹³⁰ N.D. CENT. CODE ANN. § 32-15-06.1 (West 2020).

¹³¹ *Id.*

¹³² N.D. CENT. CODE ANN. § 32-15-03 (West 2020).

¹³³ *See* N.D. CENT. CODE ANN. § 49-19-09 and 12 (West 2020).

¹³⁴ N.D. CENT. CODE ANN. § 49-19-01(1) (West 2020).

¹³⁵ N.D. CENT. CODE ANN. § 49-19-09 (West 2020).

¹³⁶ N.D. CENT. CODE ANN. § 49-19-12 (West 2020).

¹³⁷ Carbon Dioxide Underground Storage, N.D. CENT. CODE ANN. § 38-22-01 to 23 (West 2020).

¹³⁸ N.D. CENT. CODE ANN. § 38-22-10 (West 2020).

¹³⁹ N.D. CENT. CODE ANN. § 38-22-03 (West 2020).

¹⁴⁰ N.D. CENT. CODE ANN. § 38-22-14 and 15 (West 2020).

¹⁴¹ N.D. CENT. CODE ANN. § 38-22-02 (West 2020).

¹⁴² N.D. CENT. CODE ANN. § 38-22-08(4) (West 2020).

¹⁴³ N.D. CENT. CODE ANN. § 38-22-08(5) (West 2020).

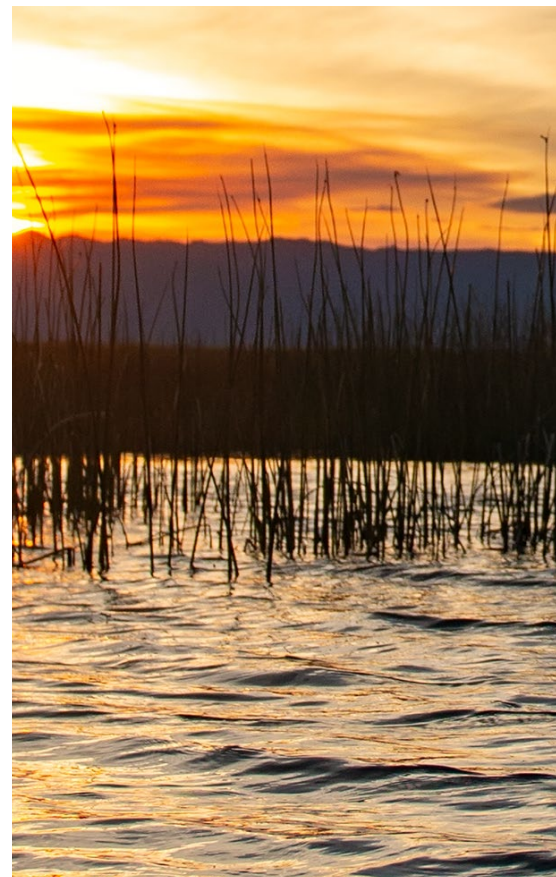
¹⁴⁴ N.D. CENT. CODE ANN. § 38-22-10 (West 2020).

¹⁴⁵ N.D. CENT. CODE ANN. 38-22-08(14) (West 2020).

A CO₂ storage operator must apply to the NDIC for a permit before beginning injection and storage operations.¹⁴⁶ The application must include a description of the storage reservoir and information on “local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features.”¹⁴⁷ The NDIC must hold a hearing before issuing a permit.¹⁴⁸ If the NDIC finds that the proposed storage facility is “suitable and feasible” for CO₂ sequestration and that CO₂ will not escape from the storage reservoir or negatively impact water sources, human health, or the environment, it may grant a permit.¹⁴⁹

Storage operators are required to pay two separate fees to the NDIC for each ton of injected CO₂.¹⁵⁰ The first fee funds NDIC permitting activities,¹⁵¹ while the second fee is deposited in a fund to defray the costs of long-term monitoring and management of storage reservoirs and facilities.¹⁵²

Storage operators maintain ownership of and liability for injected CO₂ until the NDIC issues a “certificate of project completion.”¹⁵³ Storage operators may request a certificate ten years after the conclusion of all injection operations.¹⁵⁴ The NDIC may issue a certificate if the injected CO₂ is “essentially stationary” or any migration will be unlikely to leave the storage reservoir.¹⁵⁵ Once the certificate is issued, title of and liability for both the storage facility and the injected CO₂ is transferred to the state.¹⁵⁶



“If the NDIC finds that the proposed storage facility is “suitable and feasible” for CO₂ sequestration and that CO₂ will not escape from the storage reservoir or negatively impact water sources, human health, or the environment, it may grant a permit.”

¹⁴⁶ N.D. CENT. CODE ANN. § 38-22-04 and 05 (West 2020).

¹⁴⁷ N.D. ADMIN. CODE 43-05-01-05 (2020).

¹⁴⁸ N.D. CENT. CODE ANN. § 38-22-06 (West 2020).

¹⁴⁹ N.D. CENT. CODE ANN. § 38-22-08 (West 2020).

¹⁵⁰ N.D. CENT. CODE ANN. § 38-22-14 and 15 (West 2020).

¹⁵¹ N.D. CENT. CODE ANN. § 38-22-14 (West 2020).

¹⁵² N.D. CENT. CODE ANN. § 38-22-15 (West 2020).

¹⁵³ N.D. CENT. CODE ANN. § 38-22-16 (West 2020).

¹⁵⁴ N.D. CENT. CODE ANN. § 38-22-17 (West 2020).

¹⁵⁵ *Id.*

¹⁵⁶ *Id.*

OHIO

Executive Summary

Ohio lacks a defined statutory regime for carbon dioxide sequestration. The state has minimal CO₂-EOR activities. There are no CO₂ pipelines and current state laws provide little guidance on the application of eminent domain for new CO₂ infrastructure other than common carrier requirements. Ohio precedent is unclear relative to pore space ownership though case law suggests that the surface owner controls pore space. CO₂ is generally treated as a pollutant as opposed to a commodity in Ohio.

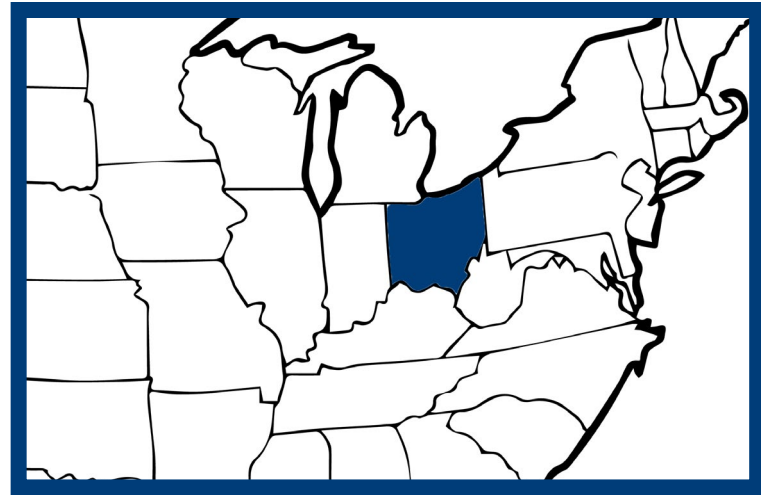
Background:

Ohio consists of 26,209,900 acres, of which 256,960 acres (or almost 1%) is owned by the federal government. No tribal lands lie within the state.

The Ohio court system has several levels. Some municipalities use Mayor's Courts to hear violations of local ordinances. County and Municipal Courts hold jurisdiction over preliminary hearings for civil cases where the amount in dispute does not exceed \$15,000. Courts of Common Pleas are the trial courts of records. Specialized divisions exist for probate and civil cases with an amount in controversy exceeding \$15,000. The Court of Claims hears and determines civil actions filed against the State of Ohio and any state agencies. Appeals Courts include the Court of Appeals and the Supreme Court of Ohio. The Court of Appeals is the intermediate appellate court; the Supreme Court of Ohio is the court of last resort in the state.

CO₂-EOR in Ohio:

Ohio has a long history of enhanced petrochemical recovery utilization, dating to the early 1900s. While significant opportunities for CO₂-EOR have been identified in Ohio,¹ no large-scale projects exist at this time. Researchers found an increase oil production following a small-scale test using approximately 80 tons of CO₂.²



Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

When interpreting a contract in Ohio, the unambiguous language of the instrument guides the courts, which do not give a construction other than that provided by the plain language of the contract.³ The terms of the written instrument determine the rights and remedies of parties to oil and gas leases.⁴ Interest has grown not only in who owns the land but who holds the rights to the mineral estate due to the gas boom in the Utica and Marcellus Shale regions.⁵ The growing interest in potentially lucrative oil and gas leases results in a large portion of Ohio mineral law being dedicated to interpretation of leases.⁶

An oil and gas lease creates a real-property interest that can be used by a mineral estate owner to permit others to explore and exploit the land's mineral resources in exchange for various types of consideration, including royalties.⁷ The duration of an oil and gas lease is generally outlined within a habendum clause as a primary, or fixed, term with a secondary term that sets forth a more indefinite duration that extends the lessee's rights under the lease on the satisfaction of certain described conditions.⁸ Leases may also include a delay-rental clause that permits the

³ See generally *Bohlen v. Anadarko E&P Onshore, L.L.C.*, 150 Ohio St. 3d 197, 80 N.E.3d 468 (2017) (quoting *Aultman Hosp. Assn. v. Community Mut. Ins. Co.*, 46 Ohio St. 3d 51, 544 N.E.2d 920 (1989)).

⁴ *Harris v. Ohio Oil Co.*, 57 Ohio St. 118, 129, 48 N.E. 502 (1897).

⁵ *Chesapeake Exploration, L.L.C. v. Buell*, 144 Ohio St. 3d 490, 493, 45 N.E.3d 185 (2015).

⁶ *Dodd v. Croskey*, 143 Ohio St. 3d 293, 294, 37 N.E.3d 147 (2015).

⁷ OHIO REV. CODE ANN. § 5301.09 (West); *Chesapeake Exploration, L.L.C.*, 144 Ohio St. at 493.

⁸ *Chesapeake Exploration, L.L.C. v. Buell*, 144 Ohio St. 3d at 507 (“A habendum clause, also referred to as a term clause, is a section of a contract that deals with the rights, interests, and other aspects of ownership being given to one of the parties.”).

¹ Mishra, S., Hawkins, J., Barclay, T. H., & Harley, M., *Estimating CO₂-EOR Potential and Co-sequestration Capacity in Ohio's Depleted Oil Fields*, 63 Energy Procedia 7785-95 (2014).

² RILEY, R., WICKS, J., & PERRY, C., SILURIAN “CLINTON” SANDSTONE RESERVOIR CHARACTERIZATION FOR EVALUATION OF CO₂-EOR POTENTIAL IN THE EAST CANTON OIL FIELD, OHIO (Baard Energy, L.L.C. 2009).

lessee to delay drilling a well during the primary term as long as the lessee compensates the lessor(s).⁹ In one case, the Supreme Court of Ohio found that non production for a period of two years or more was sufficient to constitute a cessation of production leading to automatic expiration of the lease based on the determinable term in the habendum clause.¹⁰

Absent a valid disclaimer, oil and gas leases include several implied covenants.¹¹ Notwithstanding the guiding principle of contract interpretation, Ohio courts hold that oil and gas leases are “ordinarily subject to an implied covenant to reasonably develop the land.”¹² Courts determine on a case-by-case basis whether an oil and gas lessee has breached an implied covenant.¹³ Parties to an oil and gas lease can include “express provisions to the contrary” to prevent the implied covenant of reasonable development from applying.¹⁴ Landowners’ interest in the development of the land is protected by the implied covenant of reasonable development and does not require recognition of an implied covenant to explore further.¹⁵

Due to the fractionalization of mineral rights and the challenges of identifying and locating mineral owners, the Ohio General Assembly enacted the Marketable Title Act (“MTA”) in 1961 to assist parties looking to develop mineral interests. The MTA streamlines mineral ownership by simplifying and facilitating land title transactions through the use of marketable record title,¹⁶ which operates to extinguish all prior interests through

reliance on an unbroken chain of title.¹⁷ Under the MTA, a landowner with an unbroken chain of title for 40 years can transfer the title free of any interests that existed before the beginning of the chain of title.¹⁸ However, if specific reference is made to an earlier-created interest within the chain of title, that interest is preserved.¹⁹ Following an amendment in 1973, oil and gas rights were extinguished by the MTA 40 years from the effective date of the root of title unless a “saving event” preserving the interest was found in the record chain of title.²⁰ “Saving events” include title transactions recorded in the appropriate recorder’s office, production or withdrawal where appropriate instruments are recorded in the appropriate recorder’s office, the issuance of a drilling or mining permit, and the use of the mineral interest in underground gas storage operations.²¹

At common law, a failure to produce oil or gas or extract other minerals did not subject mineral rights severed from the rights of the surface estate to abandonment or termination.²² Enacted as part of the MTA in 1989, the Dormant Mineral Act (“DMA”) was designed to protect the rights of landowners by providing that certain mineral interests could be deemed abandoned if the interests were not used in the preceding 20 years by either the original owner or their heirs and assigns.²³ In *Corban v. Chesapeake*, the Ohio Supreme Court ruled that the 1989 version of the DMA was not self-executing, meaning that severed oil, gas, and mineral rights would not automatically be deemed abandoned and vest in a surface owner.²⁴ The court in *Corban* also clarified that any surface owner attempting to merge surface and mineral rights after 2006 had to follow the 2006 version of the DMA. In *Albanese v. Batman*, the Ohio Supreme Court

⁹ Syl. pt. 3, *Brown v. Fowler*, 65 Ohio St. 507, 63 N.E. 76 (1902).

¹⁰ See *Chesapeake Exploration, L.L.C., v. Buell*, 144 Ohio St. 3d 490, 45 N.E.3d 185 (2015). See also *Browne v. Artex Oil Company*, 158 Ohio St. 3d 398, 403, 144 N.E.3d 378 (2019).

¹¹ See *Alford v. Collins-McGregor Operating Company*, 152 Ohio St. 3d 303, 306, 95 N.E.3d 382 (2018).

¹² Syl. pt. 1, *Harris v. Ohio Oil Co.*, 57 Ohio St. 118, 48 N.E. 502 (1897) (noting “an implied covenant on part of the lessee that he will drill and operate such number of oil wells on the lands as would be ordinarily required for the production of oil contained in such lands, and afford ordinary protection to the lines”).

¹³ *Alford v. Collins-McGregor Operating Company*, 152 Ohio St. 3d 303, 308, 95 N.E.3d 382 (2018).

¹⁴ Syl. pt. 2, *Beer v. Griffith*, 61 Ohio St. 2d 119, 399 N.E.2d 1227 (1980).

¹⁵ See *Alford*, 152 Ohio St. 3d at 308 (citing *Summers Oil and Gas*, Section 17:15).

¹⁶ OHIO REV. CODE ANN. § 5301.47 (West 2020) (“marketable record title” refers to an unbroken chain of title of record to any interest in land for forty years or more).

¹⁷ OHIO REV. CODE ANN. § 5301.48 (West 2020) (“A person has such an unbroken chain of title when the official public records disclose a conveyance or other title transaction, of record not less than forty years at the time marketability is to be determined, which said conveyance or other title transaction purports to create such interest, either in (a) the person claiming such interest, or (b) some other person from whom, by one or more conveyances or other title transactions of record, such purported interest has become vested in the person claiming such interest, with nothing appearing on the record, in either case, purporting to divest such claimant of such purported interest.”).

¹⁸ See *Blackstone v. Moore*, 155 Ohio St. 3d 448, 449 122 N.E.3d 132 (2018).

¹⁹ *Id.* (holding the enumerated exception of “general reference . . . to . . . interests created prior to the root of title” in the MTA as “approximate rather than accurate,” and that reference sufficient to preserve the subject royal interest was specific).

²⁰ *Corban v. Chesapeake Exploration, L.L.C.*, 149 Ohio St. 3d 512, 516, 76 N.E.3d 1089 (2016); OHIO REV. CODE ANN. § 5301.48-.49 (West).

²¹ OHIO REV. CODE ANN. § 5301.56(B)(3)(a)-(f) (West 2020).

²² *Corban*, 149 Ohio St. 3d at 515.

²³ *Id.* at 516.

²⁴ *Id.* at 520.

applied *Corban* and set forth four criteria for a severed mineral interest to be deemed abandoned and vested in the surface owner: “(i) the mineral interest cannot be in coal, (ii) the mineral cannot be held by certain entities, (iii) no saving event can have occurred during the relevant period, and (iv) the surface owner shall have served notice and filed the required statutory affidavit.”²⁵ The MTA (as amended) and the DMA were enacted partly in response to the rule at common law that “severed mineral rights were not subject to abandonment or termination for the failure to produce oil or gas.”²⁶

Split Estates

While the mineral remains underground, it is “in place” and is the same as any part of the realty, but minerals may be severed from the rest of the realty for purposes of separate ownership.²⁷ The owner who conveys the surface estate may retain an interest in the mineral estate by reservation.²⁸ While the surface estate may be separately owned, Ohio courts have recognized that when the interests have been severed, “neither the owner of the surface interest nor the owner of the mineral interest has full ownership” because “[e]ach has rights that are subject to the rights of the other.”²⁹ The owner of a mineral estate, regardless of surface estate ownership, may convey the rights to the subsurface minerals through an oil and gas lease.³⁰

Mineral estates are generally dominant to surface estates in Ohio. The Ohio Supreme Court recognizes that surface estate ownership may be completely severed from the different mineral ownerships that may reside under the surface.³¹ The Ohio Supreme Court also recognizes that, unless expressly restricted, “creation of a separate interest in the mineral with the right to remove the same, whether by deed, grant, lease, reservation or exception, confers upon the owner of the mineral a fee simple estate, which is, of course, determinable upon the exhaustion of

the mine.”³² Thus, Ohio courts recognize mineral rights as separate property rights, as such rights are created as a separate interest in the land, whether “by deed, grant, lease, reservation or exception.”³³ The intention of the parties, as evidenced by a construction of the whole instrument in light of the circumstances, determines whether the language contained in the deed creates a reservation or exception from the grant.³⁴ The words “reserving all minerals underlying the soil” in a granting clause of a deed of real estate constitute an exception of the minerals from the operation of the grant.³⁵ Absent terms that clearly and unequivocally demonstrate a different intention, a deed conveying an estate in fee must be held to have that effect.³⁶

When the mineral estate is severed from the surface estate and the mineral rights underlying the land are sold, the purchaser obtains the title to an estate in fee which terminates when the mine is exhausted.³⁷ The purchaser has the right to use or remove as much of the constraining strata from above and below the surface as reasonably required to properly mine the mineral.³⁸ When the grant that creates the estate contains no limitations, the space that may be left by the removal of the mineral remains a part of the property of the mine owner until the mine has been exhausted.³⁹ No authority exists with respect to “exhaustion” of oil and gas extraction. In connection with coal, a case from the nineteenth century stated that exhaustion occurs where “none remains to be mined.”⁴⁰ The Ohio Supreme Court later used “exhaustion” synonymously with the time at which oil

³² State ex rel. Shelly Materials, Inc. v. Clark Cty. Bd. of Commrs., 115 Ohio St. 3d 337, 344, 875 N.E.2d 59 (2007) (quoting Moore v. Indian Camp Coal Co., 75 Ohio St. 493, 499, 80 N.E. 6 (1907)). See also Gill v. Fletcher, 74 Ohio St. 295, 78 N.E. 433 (1906).

³³ *Id.*

³⁴ See Syl. pt 2, Gill v. Fletcher, 74 Ohio St. 295, 78 N.E. 433 (1906).

³⁵ See Sloan v. Lawrence Furnace Co., 29 Ohio St. 568 (1876) (holding the “minerals underlying the soil” as part of the land described in the deed and not only a “mere future in benefit or interest therein,” so the grantor undoubtedly intended to retain the fee-simple title to the minerals.).

³⁶ Edwards v. McClurg, 39 Ohio St. 41, 48 (1883) (holding a deed that conveyed “all the stone coal lying and being in, under, and upon” certain premises unto the second party and their heirs and assigns, and that the grantee had the right to abandon the contract when the grantee determined said coal was “no longer minable with economy and profit” left the grantor “no interest in the coal subject to be mortgaged as land.”).

³⁷ See Syl. pt. 1, Moore v. Indian Camp Coal Co., 75 Ohio St. 493, 80 N.E. 6 (1907).

³⁸ See Syl. pt. 2, Moore v. Indian Camp Coal Co., 75 Ohio St. 493, 80 N.E. 6 (1907).

³⁹ See Syl. pt. 3, Moore v. Indian Camp Coal Co., 75 Ohio St. 493, 80 N.E. 6 (1907).

⁴⁰ Wadsworth Coal Co. v. Silver Creek Min. & Ry. Co., 40 Ohio St. 559, 562-63 (1884).

²⁵ See *Albanese v. Batman*, 148 Ohio St. 85, 90, 68 N.E.3d 800 (2016). See also OHIO REV. CODE ANN. § 5301.56 (West 2020).

²⁶ See *Corban*, 149 Ohio St. 3d at 515.

²⁷ See *Chesapeake Exploration, L.L.C. v. Buell*, 144 Ohio St. 3d 490, 494, 45 N.E.3d 185 (2015) (quoting *Pure Oil Co. v. Kindall*, 116 Ohio St. 188, 201, 156 N.E. 119 (1927)).

²⁸ *Id.*

²⁹ See *Snyder v. Ohio Dept. of Natural Resources*, 140 Ohio St. 3d 322, 326, 18 N.E.3d 416 (2014).

³⁰ See *Chesapeake Exploration, L.L.C. v. Buell*, 144 Ohio St.3d 490, 494, 45 N.E.3d 185 (2015). See also *Brown v. Fowler*, 65 Ohio St. 118, 128, 48 N.E. 502 (1897) (noting that even if the lease is termed a sale of all the oil underlying the land, the oil remaining under the property after the lease expires belongs to the landowner).

³¹ Nicholas R. House, *Conflicting Property Rights Between Conservation Easements and Oil and Gas Leases in Ohio: Why Current Law Could Benefit Conservation Efforts*, 55 WM. & MARY L. REV. 1587, 1599 (2014) (citing Ronald W. Polston, *Surface Rights of Mineral Owners—What Happens When Judges Make Law and Nobody Listens?*, 63 N.D. L. REV. 41, 42-44 (1987)).

and gas are no longer “found in paying quantities.”⁴¹ The latter case involved a lease that expressly provided for termination when “oil and gas shall cease to be produced in paying quantities on such land.”⁴² Therefore, if there is any possibility of profitable oil and gas production on the property, one could argue that the resource is not yet exhausted.

“The Ohio Supreme Court recognizes that a natural right belongs to a surface owner to use his land in the natural state, and if surface ownership is severed from mineral ownership, that surface ownership will be supported by the underlying classes of mineral.”

In Ohio, special rules of construction exist regarding a mineral owner’s right to destroy the surface. A severed mineral estate is considered to include the right to use the surface as reasonably necessary for the proper working of the mine and the obtaining of the minerals, unless the language of the mineral conveyance contradicts such construction.⁴³ When mineral rights are severed from the surface, only that portion of the minerals that can be extracted by the mineral rights owner without injury to the superincumbent surface may be extracted, unless it was the express intent of the surface estate holder to part with the right of subjacent support.⁴⁴ When the surface is conveyed and the minerals reserved, or the minerals granted and the surface not conveyed, the obligation to protect the superincumbent surface exists.⁴⁵

⁴¹ Harris v. Ohio Oil Co., 57 Ohio St. 118, 130-32, 48 N.E. 502 (1897).

⁴² *Id.*

⁴³ Chesapeake Exploration, L.L.C. v. Buell, 144 Ohio St. 3d 490, 494, 45 N.E.3d 185 (2015) (quoting Quarto Mining Co. v. Litman, 42 Ohio St. 2d 73, 83, 326 N.E.2d 676 (1975)).

⁴⁴ Burgner v. Humphrey, 41 Ohio St. 340, 352 (1884).

⁴⁵ *Id.*

The presumption is that the owner of the minerals is not to injure the owner of the soil above.⁴⁶ The Ohio Supreme Court recognizes that a natural right belongs to a surface owner to use his land in the natural state, and if surface ownership is severed from mineral ownership, that surface ownership will be supported by the underlying classes of mineral.⁴⁷ In *Ohio Collieries Co. v. Cocke*, the Court held that a sale of all coal underlying a tract of land does not necessarily imply a release of the right to surface support.⁴⁸ The waiver of such a right must be express in the grant or clearly imported in the instrument used to convey the estate.⁴⁹

Pore Space Ownership

Regarding gas storage, no specific case law or statutes govern pore space ownership. In the context of subsurface trespass from injection wells, the court in *Chance v. B.P. Chemicals, Inc.* limited a landowner’s right to trespasses that “actually interfere” with the “reasonable and foreseeable” use of the subsurface.⁵⁰ The court reasoned that modern property rights have changed and that the surface owner’s right to the pore space is not absolute.⁵¹ This conclusion may support the proposition that surface owners retain pore space rights, but with limitations. An Ohio federal court ruling found that a gas owner “did not lose title to the natural gas by injecting it into the underground.”⁵² This ruling could support a future Ohio court finding that the surface owner retains the right to the pore space.⁵³ However, one could argue otherwise, and federal court decisions are not binding on state law matters.

⁴⁶ Burgner, 41 Ohio St. at 352-53 (holding a clause that the mineral rights holder could remove “all mineral coal” did not mean that it could be removed without considering the effect of its removal on the surface soil and that “clear and unequivocal language in the deed” was necessary to dispense with subjacent support).

⁴⁷ *Ohio Collieries Co. v. Cocke*, 107 Ohio St. 238, 252, 140 N.E. 356 (1923).

⁴⁸ *Id.* at 254.

⁴⁹ *Id.*

⁵⁰ *Chance v. B.P. Chemicals, Inc.*, 670 N.E.2d 985, 993 (Ohio 1993).

⁵¹ *Id.* at 992.

⁵² *Columbia Gas Transmission Corp. v. Smail*, No. C86-1196A, 1986 WL 20906 (N.D. Ohio July 18, 1986) at *5.

⁵³ See Stephanie L. Burt, *Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions*, 4 *JOULE: DUQ. ENERGY & ENVTL. L.J.* 1, 7-8 (2016).

Finally, an older Ohio court case found that holding mineral rights does not create “a right of storage.”⁵⁴ Subsurface storage easements and leases exist within the State, which could imply that storage constitutes a separate estate to convey.⁵⁵ In summary, pore space ownership is uncertain in Ohio. No relevant case law was found regarding pore space in the context of produced water and carbon storage.

Water Rights

Ohio follows the reasonable use riparian doctrine for surface water: the owner of land that abuts a water body has the right to withdraw a reasonable amount of water from the water body, while sharing the water body with other riparian owners.⁵⁶ The right of the riparian owner to use water is usufructuary only, meaning that the right is to use the water, not a right in the water itself.⁵⁷ The water itself is not owned until captured and under the control of the riparian owner.

For groundwater withdrawals, Ohio uses the Restatement (Second) of Torts Rule.⁵⁸ This Rule states that a landowner who withdraws groundwater from the land and uses it for a beneficial purpose is not subject to liability for interference with the use of water by another, unless:

- (a) the withdrawal of ground water unreasonably causes harm to a proprietor of neighboring land through lowering the water table or reducing artesian pressure,
- (b) the withdrawal of ground water exceeds the proprietor’s reasonable share of the annual supply or total store of ground water, or
- (c) the withdrawal of ground water has a direct and substantial effect upon a watercourse or lake and unreasonably causes harm to a person entitled to the use of its water.⁵⁹

⁵⁴ *Chartiers Oil Co. v. Curtiss*, 1911 WL 1615 (Ohio Cir. Ct. Nov. 1911), *aff’d*, 106 N.E. 1053 (1913).

⁵⁵ *See Columbia Gas Transm. Corp. v. An Exclusive Nat. Gas Storage Easement*, 67 Ohio St. 3d 463, 620 N.E.2d 48 (Ohio 1993). *See also Myers v. E. Ohio Gas Co.*, 364 N.E.2d 1369, 1369-71 (Ohio 1977).

⁵⁶ *See City of Canton v. Shock*, 66 Ohio St. 19 (1902). *See also Cooper v. Williams*, 4 Ohio 253, 286 (1831), *affirmed on rehearing*, 5 Ohio 391 (1832); *Buckingham v. Smith*, 10 Ohio 288 (1840); *McElroy v. Goble*, 6 Ohio St. 187 (1856); *Bisher v. Richards*, 9 Ohio St. 495 (1859); *Frazier v. Brown*, 12 Ohio St. 294 (1861); *Accurate Die Casting Co. v. Cleveland*, 2 Ohio App. 3d 386, 389, 442 N.E.2d 459 (1981).
⁵⁷ *See Cooper*, 4 Ohio at 286, *affirmed on rehearing*, 5 Ohio 391 (1832). *See also Salem Iron Co. v. Hyland*, 74 Ohio St. 160, 165 (1906).

⁵⁸ *Cline v. American Aggregates Corp.*, 15 Ohio St. 3d 384, 474 N.E.2d 324 (1984).

⁵⁹ Restatement (Second) of Torts § 858(1) (1979).

The right to reasonable use of the groundwater is a property right, entitled to constitutional protections.⁶⁰ The Chief of DOGRM may identify and protect all aquifers or parts of aquifers that meet the definition of “underground source of drinking water,” even if the aquifer was not previously identified as an underground source of drinking water.⁶¹ An aquifer may be designated an “exempted aquifer” only after notice and opportunity for a public hearing, and when it meets all the criteria in the regulatory code.⁶²

Lithium Ownership and Extraction

No statutes or cases specifically contemplate lithium extraction. However, many of Ohio’s natural resource statutes include “minerals” or “mineral resource extraction,” which would likely be sufficiently broad to include lithium extraction.⁶³

Classification of CO₂: Pollutant

CO₂ is regulated as a pollutant in Ohio’s statutes. For example, Ohio Statutes direct the Public Utilities Commission develop guidelines for CO₂ emissions created by facilities generating electricity.⁶⁴ Ohio statutes do not specify whether the state’s severance tax for natural gas would apply to CO₂.⁶⁵

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The Ohio Department of Natural Resources acts through the Division of Oil and Gas Resource Management (“DOGRM”) to control and implement the oil and gas permitting laws and regulations of the state, which includes well location, spacing, and well operations.⁶⁶ The Chief of the DOGRM, with the approval of the technical advisory council on oil and gas⁶⁷ may adopt, amend, or rescind minimum acreage spacing requirements between drilling units, and designate minimum distances of drilling units from tract boundaries.⁶⁸ The authority to create rules regarding spacing pertains to new wells and existing wells to be deepened, plugged, or reopened to a resource supply other than the existing pool for resource extraction.⁶⁹

⁶⁰ *McNamara v. Rittman*, 107 Ohio St. 3d 243, 2005-Ohio-6433, 838 N.E.2d 640 (2005).

⁶¹ OHIO ADMIN. CODE 1501:9-7-06(A) (2020).

⁶² OHIO ADMIN. CODE 1501:9-7-06(B) (2020).

⁶³ *See generally* OHIO REV. CODE ANN. § 1514.01 (West 2020); OHIO REV. CODE ANN. § 1513.10 (West 2020).

⁶⁴ OHIO REV. CODE ANN. § 4928.68 (West 2020).

⁶⁵ 57 OHIO REV. CODE ANN. § 5749.02 (West 2020).

⁶⁶ OHIO REV. CODE ANN. § 1509.02 (West 2020).

⁶⁷ OHIO REV. CODE ANN. § 1509.38 (West 2020).

⁶⁸ OHIO REV. CODE ANN. § 1509.24(a) (West 2020).

⁶⁹ OHIO REV. CODE ANN. § 1509.24(b) (West 2020).

The DOGRM also receives, evaluates, and decides on applications from operators regarding mandatory pooling.⁷⁰ Decisions made by the DOGRM can be appealed by those adversely affected by the order to the state’s Oil and Gas Commission.⁷¹ Ohio prescribes to the Rule of Capture, but qualified with the “Correlative Rights Doctrine,” which states an owner has a right to a “reasonable opportunity” to retrieve oil and gas under her tract.⁷² To protect these rights, Ohio mandates “pooling,” which is the uniting of independent surface tracts above a “common source”⁷³ before Ohio will allow drilling for natural gas or oil. Even unwilling participants in the pool are paid proportional royalties.⁷⁴

Adjoining tract owners may voluntarily agree to pool the tracts to form a drilling unit which conforms to statutory spacing requirements.⁷⁵ The Ohio courts prefer voluntary pooling (per statute)⁷⁶ to compulsory pooling, and will reverse an approved application if “applicant’s efforts to pool voluntarily were not just and equitable.”⁷⁷ If just and equitable negotiations fail to produce a voluntary pooling agreement of all landowners in a tract, an owner can apply to the DOGRM for a mandatory pooling order if the tract size or shape does not meet statutory requirements for a drilling unit.⁷⁸

The acreage control threshold for a forced pooling order is 65%.⁷⁹ The application for forced pooling goes to the Chief of DOGRM who, based upon all information “reasonably required by the chief” and an accompanying permit application for drilling, reopening, or converting a well, decides on the application for mandatory pooling.⁸⁰ The Chief shall provide notice to “all mineral right owners of tracts within the area proposed to be pooled by an order and included within the drilling unit of the filing application and of their right to a hearing.”⁸¹ After a hearing, or after 30 days pass from notice to all mineral owners, the Chief may decide to approve the mandatory pooling application.⁸²

In Ohio, subsurface trespass “is an unlawful entry upon the property of another.”⁸³ To prove subsurface trespass, the property owner must prove their possessory interest in the subsurface property, and the “offending party entered the property without consent or prior authorization.”⁸⁴ However, the owner’s property right in the subsurface is not absolute, and the property owner can only exclude invasions of the subsurface property if the entry upon the property “actually interferes with [their] reasonable and foreseeable use of the subsurface.”⁸⁵ For injection wells, a theory of indirect trespass (“lateral migration of injectate”)⁸⁶ can only be successful if the plaintiff can prove “some type of physical damages or interference with use.”⁸⁷

The rule of capture does not apply to coal. If coal is taken wrongfully and intentionally, damages are calculated by the value of the extracted coal. When taking is done unintentionally, the value is of the coal “in place,” which includes all factors that increase or decrease the coal’s value.⁸⁸

Injection well permits fall under Title 61, Section 6111.044 of the Ohio Revised Code, which is dedicated to Water Pollution Control.⁸⁹ The application for an injection well will be denied by the Director of the Ohio Environmental Protection Agency (“OEPA”) if the proposed activities are found to “pose an unreasonable risk of inducing seismic activities, including geologic fractures, or contamination of an underground source of drinking water.”⁹⁰ The applicant must demonstrate that no such unreasonable risks exist.⁹¹ If the Chief of the Division of Water or the Director of the OEPA determines the application fails to identify and delineate underground sources of drinking water in the area of review, the application must be denied.⁹² The application must comply with the Federal Water Pollution Act and Safe Drinking Water Act regulations.⁹³

The DOGRM will deny applications for wells injecting fluids or carbon dioxide “for the secondary or tertiary recovery of oil or natural gas or for the storage of hydrocarbons” will not contaminate “underground water that supplies or can be reasonably expected to supply any

⁷⁰ OHIO REV. CODE ANN. § 1509.27 (West 2020).

⁷¹ OHIO REV. CODE ANN. § 1509.36 (West 2020).

⁷² See, e.g., *Kerns v. Chesapeake Exploration, L.L.C.*, 762 Fed. Appx. 289 (6th Cir. 2019).

⁷³ OHIO REV. CODE ANN. § 1509.27 (West 2020).

⁷⁴ OHIO REV. CODE ANN. § 1509.27(F) (West 2020).

⁷⁵ OHIO REV. CODE ANN. § 1509.26 (West 2020).

⁷⁶ OHIO REV. CODE ANN. § 1509.27 (West 2020).

⁷⁷ See *Johnson v. Kell*, 626 N.E. 2d 1002 (Ohio Ct. App. 1992).

⁷⁸ OHIO REV. CODE ANN. § 1509.24 (West 2020).

⁷⁹ OHIO REV. CODE ANN. § 1509.28 (West 2020).

⁸⁰ OHIO REV. CODE ANN. § 1509.27 (West 2020).

⁸¹ *Id.*

⁸² *Id.*

⁸³ See *Chance v. BP Chemicals, Inc.*, 670 N.E. 2d 985, 991 (Ohio 1996).

⁸⁴ See *Baatz v. Columbia Gas Transmission, L.L.C.*, 929 F.3d 767 (6th Cir. 2019).

⁸⁵ See *Chance*, 670 N.E. at 992.

⁸⁶ *Id.* at 993.

⁸⁷ *Id.*

⁸⁸ See *Brady v. Stafford*, 152 N.E. 188, 191-92 (1926).

⁸⁹ OHIO REV. CODE ANN. § 6111.044 (West 2020).

⁹⁰ *Id.*

⁹¹ *Id.*

⁹² OHIO REV. CODE ANN. § 6111.044 (West 2020).

⁹³ *Id.*

public water system, such that the presence of any such contaminant may result in the system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons."⁹⁴ Section 1509.21 of the Ohio Revised Code contains provisions regarding "entry to conduct inspections and to examine records to ascertain compliance with this section" and the "maintenance of information through monitoring, recordkeeping, and reporting."⁹⁵ Injection wells are also subject to the regulations of the OEPA.⁹⁶ However, obtaining a permit for a Class II or Class III well under Chapter 1509 "exempts the permit holder from requirements under this rule."⁹⁷ Carbon dioxide injection for resource recovery, as referred to in the oil and gas statutory regime,⁹⁸ would likely fall under a Class II designation.⁹⁹

Pipeline Regulation

In Ohio, OPS inspects and enforces the pipeline safety regulations for interstate and intrastate hazardous liquid pipeline operators.¹⁰⁰ However, for interstate gas pipeline operators in Ohio, OPS enforces the pipeline safety regulations based on the state inspections by signed agreement with OPS.¹⁰¹ For intrastate gas pipeline operators in Ohio, the state inspects and enforces the pipeline safety regulations through certification by OPS.¹⁰² The Public Utilities Commission of Ohio performs this work.¹⁰³ By letter dated January 6, 2020, OPS notified the state that its enforcement of Ohio's excavation damage prevention law was "adequate."¹⁰⁴

Under Ohio's Natural Gas Pipeline Safety Act, the Public Utilities Commission administers and enforces the Act, including rules concerning pipeline safety and

enforcement procedures.¹⁰⁵ If the commission determines that a civil action must be brought against an operator to enforce the orders of the commission, it may work with the Attorney General to obtain appropriate relief.¹⁰⁶

State Environmental Laws

Ohio obtained primacy for the Class II UIC program under Section 1425 of the SDWA on September 22, 1983. The Ohio Class II UIC program is managed by DOGRM under the authority found in Section 1509 of the Ohio Revised Code. Under Section 1509.03 of the Revised Code, the Chief of DOGRM is required to adopt rules for the administration, implementation, and enforcement of Chapter 1509. Section 1509.22 of the Code requires the Chief to adopt rules regarding the injection into wells of brine resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production.¹⁰⁷ While Ohio holds primacy for UIC Classes I – V, Ohio does not hold primacy regarding Class VI injection wells.

Industrial Siting Requirements

The Ohio Power Siting Board has jurisdiction over major utility projects, including gas pipelines, though its jurisdiction excludes pipelines for "raw natural gas" including CO₂ pipelines from gas processing and natural gas liquids fractionation plants.¹⁰⁸

Local Regulation

While local authorities retain some power under Revised Code Chapter 1509, which regulates oil and gas wells, productions, and operations, local governments may not exercise their authority in a manner that discriminates against, unfairly impedes, or obstructs oil and gas activities and operations.¹⁰⁹ However, state law provides the state government with the "sole and exclusive authority" to regulate the permitting, location, and spacing of oil and gas wells and production operations within the state.¹¹⁰ Section 1509.61 of the Code further provides that local governments must conduct public meetings concerning any lease agreements which may exist in an urbanized area.¹¹¹

⁹⁴ OHIO REV. CODE ANN. §1509.21 (West 2020).

⁹⁵ *Id.*

⁹⁶ See OHIO ADMIN. CODE 3745-34 et seq. (2020).

⁹⁷ OHIO ADMIN. CODE 3745-34-12 (2020).

⁹⁸ OHIO REV. CODE ANN. §1509.21 (West 2020).

⁹⁹ UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Underground Injection Control (UIC): Class II Oil and Gas Related Injection Wells, <https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells> (last visited Sept. 15, 2020).

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

¹⁰² PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, Regulatory Fact Sheet, *supra* note 101.

¹⁰³ *Id.*

¹⁰⁴ E-mail from Massoud Tahamtani, Deputy Associate Administrator, Policy and Programs, Office of Pipeline Safety, to Samuel Randazzo, Chairman, Public Utilities Commission of Ohio (Jan. 6, 2020), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-05/Signed-OH-Notice-of-Adequacy-Letter-for-2019-PHP-20-0104.pdf>.

¹⁰⁵ OHIO REV. CODE ANN. § 4905.91 (West 2020).

¹⁰⁶ OHIO REV. CODE ANN. § 4905.96 (West 2020).

¹⁰⁷ Groundwater Protection Council, Ohio Dep't of Nat. Res. Div. of Oil & Gas, *State of Ohio Class II UIC Program Peer Review*, 13-14 (Jan. 2017) http://www.gwpc.org/sites/default/files/2017OhioClassIIPeerReviewFinal_0.pdf.

¹⁰⁸ OHIO REV. CODE ANN. § 4906.01 (West 2020).

¹⁰⁹ OHIO REV. CODE ANN. § 1509.02 (West 2020).

¹¹⁰ *Id.*

¹¹¹ *Simmers, Chief, Div. of Oil & Gas Res. Mgt. v. N. Royalton*, 65 N.E.3d 257, 264 (Ohio Ct. App. 2016).

In 2015, the Ohio Supreme Court held that a local ordinance requiring oil and gas operations to obtain a “zoning certificate,” pay application fees, wait one year after issuance of the permit to drill, and participate in public hearings was preempted by state law.¹¹² The Court further held that local setback provisions were preempted by state law, but that the determination was based on the setbacks the state prescribes.¹¹³ A municipal ordinance must yield to a state statute if: (1) the ordinance is an exercise of the police power, rather than of local self-government, (2) the statute is a general law, and (3) the ordinance is in conflict with the statute.¹¹⁴

In 2016, the Ohio Court of Appeals held that the people of a city, through a referendum, do not possess the authority, independent from the city itself, to enact local ordinances that conflict with state law.¹¹⁵ Additionally, local zoning ordinances that limit land use to “certain zoning districts without regulating the details of oil and gas drilling expressly addressed by Revised Code Chapter 1509” are not preempted by state law.¹¹⁶

Tribal Land

Nothing was found regarding tribal lands in Ohio.

Eminent Domain:

Ohio’s Uniform Eminent Domain Act provides that no agency shall appropriate real property, except as necessary and for public use.¹¹⁷ In any appropriation, the taking agency must show by a preponderance of the evidence that the taking is necessary and for a public use.¹¹⁸ A company cannot appropriate land in which it does not intend to have any real or beneficial interest or use.¹¹⁹

If the property owner does not accept the good faith offer made by the agency, and the parties cannot agree on the purchase price of the property, the agency should file a petition with the court to appropriate the

property.¹²⁰ The burden of proof is on the agency, except when approval by a state or federal regulatory authority of an appropriation by a public utility or common carrier creates an irrebuttable presumption of the necessity for the appropriation.¹²¹ Subject to the irrebuttable presumption, only a judge may determine the necessity of appropriation.¹²²

The Ohio Constitution explicitly states “no right-of-way shall be appropriated to the use of any corporation, until full compensation . . . irrespective of any benefit from any improvement proposed by such corporation, which compensation shall be ascertained by a jury of twelve men, in a court of record, as shall be prescribed by law.”¹²³ The power of eminent domain has been delegated to companies organized to transport or store gas, petroleum, coal, or its derivatives.¹²⁴ However, these provisions do not confer power to appropriate any portion, or confer any right in, any street, alley, highway, or other public way or land situated within any municipal corporation without such municipal corporation’s consent.¹²⁵

A company described in Section 1723.01 of the Revised Code, for transportation of natural gas, petroleum, coal or its derivatives, water, and electricity, is a common carrier.¹²⁶ These transporters are subject to the duties and liabilities of a common carrier under state law.¹²⁷ This classification includes any entity engaged in the business of transporting petroleum through tubing, pipes, or conduits as a common carrier.¹²⁸

Ohio Revised Code Section 4933.151 defines the power of eminent domain by water works companies. Any company organized for supplying water for public and private use may enter upon any land, whether held by an individual or private corporation, unless that land is owned by and essential to the purposes of another corporation possessing the power of eminent domain.¹²⁹

¹²⁰ See OHIO REV. CODE ANN. § 163.05 *et seq.* (West 2020).

¹²¹ OHIO REV. CODE ANN. § 163.09(B)(1)(c).

¹²² OHIO REV. CODE ANN. § 163.09(B)(2). See *Sunoco Pipeline L.P. v. Teter*, 63 N.E.3d 160, 2016-Ohio-7073 (7th Cir. 2016) (holding that Sunoco’s petition for appropriation and condemnation of land for the purposes of running pipeline that would transport propane and butane supported finding of public use; the landowner failed to overcome the presumption of necessity); (“Necessity means reasonably convenient or useful to the public; it is not limited to an absolute physical necessity.”).

¹²³ OHIO CONST. art. XIII, § 5.

¹²⁴ See OHIO REV. CODE ANN. § 1723.01 *et seq.* (West 2020). For functions of a hydraulic company, see OHIO REV. CODE § 1723.05.

¹²⁵ OHIO REV. CODE ANN. § 1723.03 (West 2020).

¹²⁶ OHIO REV. CODE ANN. § 1723.08 (West 2020).

¹²⁷ *Id.*

¹²⁸ *Id.*

¹²⁹ OHIO REV. CODE ANN. § 4933.151 (West 2020).

¹¹² State ex rel. Morrison v. Beck Energy Corp., 37 N.E.3d 128 (Ohio 2015).

¹¹³ *Id.*

¹¹⁴ *Id.*

¹¹⁵ See *Mothers Against Drilling In Our Neighborhood v. State*, 60 N.E.3d 727 (Ohio Ct. App. 2016).

¹¹⁶ See State ex rel. Kostoff v. Beck Energy Corp., 134 N.E.3d 775, 782 (Ohio Ct. App. 2019).

¹¹⁷ See *Norwood v. Horney*, 853 N.E.2d 1115, 110 Ohio St.3d 353 (2006) (discussing what constitutes public use).

¹¹⁸ OHIO REV. CODE ANN. § 163.021 (West 2020).

¹¹⁹ See *Parkside Cemetery Ass’n v. Cleveland, Bedford & Geauga Lake Traction Co.*, 112 N.E. 596, 93 Ohio. St. 161 (1915) (“There is no authority for a railroad company to appropriate land in which it does not intend to have any real or beneficial interest or use, but which it is attempting as a ‘dummy’ corporation to appropriate for the sole use and benefit of another company.”).

Geologic CO₂ Storage Regulation and Incremental Storage:

Our research did not locate relevant information could be located regarding storage facilities and CO₂ in Ohio.¹³⁸ However, Ohio grants regulatory exemptions for investment by natural gas companies in gathering lines, storage facilities, and related services.¹³⁹

Ohio requires a permit issued by the DOGRM before conducting secondary or additional recovery operations, including any underground injection of carbon dioxide for the secondary recovery of oil or natural gas *unless* a rule of the chief expressly authorizes such operations without a permit.¹⁴⁰ Additionally, any permit required by Section 1509.05 of the Revised Code must be obtained.¹⁴¹ Permit application procedures are defined in Sections 1509.06 and 1509.21 of the Revised Code.

The Chief of the DOGRM may authorize tests to evaluate whether fluids or carbon dioxide may be injected in a reservoir and to determine the maximum allowable injection pressure.¹⁴² The Chief will not issue a permit for the underground injection of fluids for the secondary or tertiary recovery of oil or natural gas or for the storage of hydrocarbons that are liquid at standard temperature and pressure, *unless* the Chief concludes that the injection will not result in underground water contamination.¹⁴³

Such qualifying company may appropriate land deemed necessary for the acquisition, construction, installation, operation, or maintenance of pumps, storage tanks, aqueducts, and water pipes, and other structures and appliances necessary for the maintenance of pressure and the purification of water, and for rights-of-way over such land and adjacent for the purpose of access to any part of such land.¹³⁰

Any municipal corporation may appropriate real estate within its limits to construct, open, excavate, improve, or extend any canal or watercourse,¹³¹ for drains and water closets,¹³² and for providing a water supply for itself and its inhabitants by the construction of wells, pumps, cisterns, aqueducts, water pipes, dimes, reservoirs, and water works.¹³³

Further, to transport natural gas, petroleum, water, or electricity using tubing, pipes, conduits, wires, or cables, a municipal corporation may enter upon any private land to examine or survey lines for such entities.¹³⁴ The municipal corporation may appropriate the amount of land necessary for the laying down or building of such facilities and for the erection of tanks and the reservoirs for the storage of water for transporting stations along such lines.¹³⁵

The right of appropriation shall be exercised in the same manner provided by Sections 163.01 to 163.22 of the Revised Code.

Ohio Revised Code section 719.01 lists the property interests subject to eminent domain by municipal corporations. This list omits subsurface rights, and minimal case law exists on this issue.¹³⁶

Ohio Revised Code Section 719.01 fails to address eminent domain authority by municipal corporations for CO₂ storage. However, Section 1571.17 of the Revised Code enables a gas corporation to appropriate private property for the purposes of transporting, selling, or storing gas in connection with the establishment, operation, or protection of a gas storage reservoir.¹³⁷

¹³⁰ *Id.*

¹³¹ OHIO REV. CODE ANN. § 719.01(I) (West 2020).

¹³² OHIO REV. CODE ANN. § 719.01(J) (West 2020).

¹³³ OHIO REV. CODE ANN. § 719.01(M) (West 2020).

¹³⁴ OHIO REV. CODE ANN. § 743.39 (West 2020).

¹³⁵ *Id.*

¹³⁶ See State ex. rel E. Ohio Gas Co. v. Board of Cty. Comm’r of Stark Cty., 980 N.E.2d 1056, 2012-Ohio-4533 (5th Cir. 2012) (holding an easement for public highway purposes creates both surface and subsurface property rights, overruling St. Albans Township Board of Trustees v. Columbia Gas Transmission Corp., 688 N.E.2d 48).

¹³⁷ See generally OHIO REV. CODE ANN. § 1571.17 (West 2020).

¹³⁸ *But see* OHIO REV. CODE ANN. § 905.41 (providing that storage facilities for anhydrous ammonia, a gas with similar physical properties to carbon dioxide, must contact officials who may consider past violations when determining if the facility will be allowed).

¹³⁹ OHIO REV. CODE ANN. § 4929.041 (West 2020).

¹⁴⁰ OHIO REV. CODE ANN. § 1509.21 (West 2020) (emphasis added).

¹⁴¹ See OHIO REV. CODE ANN. § 1509.05 (West 2020) (Permit for drilling, reopening, converting, or plugging back a well).

¹⁴² OHIO REV. CODE ANN. § 1509.21 (West 2020).

¹⁴³ *Id.* (emphasis added).

PENNSYLVANIA

Executive Summary

Minimal CO₂-EOR activities occur in the state. Regulatory risks and uncertainty regarding the cost and extent of regulation pose a significant hurdle to expansion of CO₂-EOR or to geologic storage activities in the state. No CO₂ distribution network exists, and current state laws appear to specifically exclude CO₂ from eminent domain statutes. Ownership of pore space is unclear. Pennsylvania has no statutory regime for carbon dioxide sequestration.

Background:

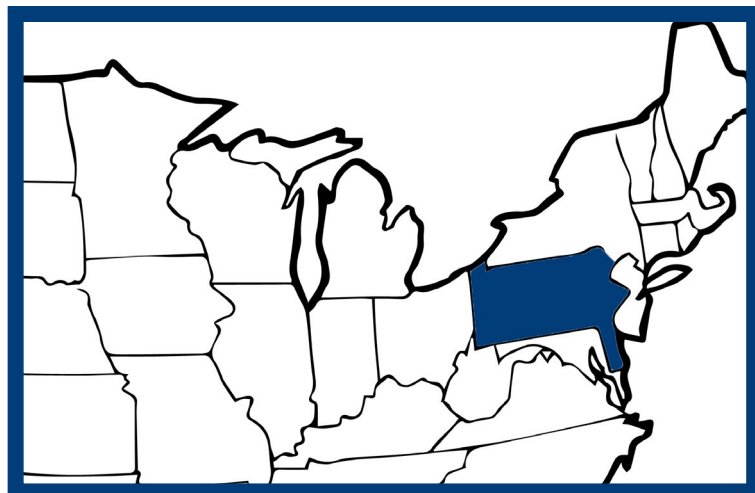
Pennsylvania consists of 28,684,800 acres. Of that total, 622,160 acres (approximately 2.2%) are federal lands. No tribal lands lie within the state.

Pennsylvania has a common law legal system. All of Pennsylvania's courts are part of the Unified Judicial System of Pennsylvania, containing three basic levels: minor courts, Courts of Common Pleas, and statewide intermediate appellate courts. Minor courts include Magisterial District Courts and the Philadelphia Municipal Court; these courts decide small claims and hold preliminary hearings. Courts of Common Pleas are trial courts and hear appeals from the Minor courts.

Two statewide intermediate appellate courts exist: the Superior Court, which hears appeals in criminal and civil cases from the Courts of Common Pleas, and the Commonwealth Court, which handles civil actions brought by and against the state and appeals from state agency decisions. The Supreme Court of Pennsylvania hears appeals from the Intermediate Appellate Courts. The Supreme Court of Pennsylvania is the highest in the state and exercises authority over all other courts.

CO₂-EOR in Pennsylvania:

Pennsylvania has a long history of EOR, with early examples dating back to 1880. Many standard enhanced recovery practices were first developed in the state, though, historically, miscible CO₂ recovery has not been used.¹



Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

When construing a deed or lease in Pennsylvania, some general principles govern interpretation. First, the contract receives a reasonable interpretation based on the intention of parties at the time of execution, gathered by reading the entire instrument.² If ambiguous language of the instrument suggests two constructions, the construction that provides the most rational and probable agreement that does justice to both parties is preferred.³

Courts also give effect to the intention of the parties when construing reservations of property.⁴ If one person grants a portion of their property to another and the instrument contains ambiguous language, the language is construed most strongly against the grantor, unless the grantee drafted the grant and was responsible for the ambiguity.⁵ Similarly, if a grant reserves something to the grantor, the reservation is construed more favorably to the grantee.⁶ Reservations must be considered when attempting to interpret the deed as a whole and gather the parties' intentions.⁷ To determine the scope of mining rights, construction is held against the reservation when the rights contained in the instrument are too ambiguous.⁸

² See generally *Wilkes-Barre Township School District v. Corgan*, 403 Pa. 383, 386, 170 A.2d 97 (1961); See also *Stewart v. Chernicky*, 439 Pa. 43, 49, 266 A.2d 259 (1970).

³ *Id.* at 387.

⁴ See *In re Conveyance of Land Belonging to City of Dubois*, 461 Pa. 161, 169-70, 335 A.2d 352 (1975); See also *Dunham & Shortt v. Kirkpatrick*, 101 Pa. 36, 43-44 (1882) (severance of mineral rights).

⁵ See *New Charter Coal Co. v. McKee*, 411 Pa. 307, 312, 191 A.2d 830 (1963).

⁶ *Id.*

⁷ *Id.* at 315.

⁸ *Stewart v. Chernicky*, 439 Pa. 43, 266 A.2d 259 (1970). See also *New Charter Coal Co. v. McKee*, 411 Pa. 307, 191 A.2d 830 (1963); *Heidt v. Aughenbaugh Coal Co.*, 406 Pa. 188, 176 A.2d 400 (1962);

¹ RONALD RILEY ET AL., EVALUATION OF CO₂-ENHANCED OIL RECOVERY AND SEQUESTRATION OPPORTUNITIES IN OIL AND GAS FIELDS IN THE MRCSP REGION: PHASE II TASK REPORT (Oct. 1, 2005 – Jan. 31, 2009) (DOE Cooperative Agreement No. DE-FC26-05NT42589).

Pennsylvania courts have consistently held that “exception” and “reservation” of rights are synonymous and fairly interchangeable words with any technical distinctions disregarded.⁹ When anything is excepted, “all things that are depending on it and necessary for obtaining it are excepted also.”¹⁰

Pennsylvania does not consider oil and gas to be classified as “minerals” in a deed or lease because gas and oil are not of a metallic nature.¹¹ Pennsylvania courts reason that the only permissible construction of a private deed is what a common layperson would understand of minerals at the time of conveyance.¹² Pennsylvania law has long recognized the Dunham Rule: a rebuttable presumption that if the parties convey land with a reservation or exception of “minerals” without specific mention of natural gas or oil, the parties did not intend to include natural gas or oil in the word “minerals.”¹³ This presumption may be rebutted with clear evidence that the parties intended to include natural gas and/or oil at the time of the conveyance.¹⁴ In its review of whether the parties considered petroleum a mineral at the time of conveyance, the *Dunham* court acknowledged the breadth of inorganic materials that can be classified as “minerals.”¹⁵ Holding that a reservation that embraces the term “minerals” completely would render any grant containing it void, the Court limited the meaning of “minerals” as it is used in a deed reservation or grant to not include hydrocarbons.¹⁶ In 2013, the Supreme Court of Pennsylvania reaffirmed the Dunham Rule as controlling law in Pennsylvania in its decision as to whether natural gas rights should be considered “mineral rights” by extending the Rule to include natural gas extracted from the Marcellus shale play.¹⁷

Split Estates

Three separate, distinct estates exist in Pennsylvania. In addition to the surface and mineral estates, there is the “support estate,” for which conveyance to the mineral estate owner must be express rather than implied.¹⁸ If a lessor expressly waives any right to surface support, the lessor does not possess a reversion, remainder, or right of reversion in the support estate that they could convey to a third party.¹⁹ The support state refers to the duty owed by mineral estate owners to leave sufficient support for the surface estate so it is unaffected by subsidence.²⁰ However, if the mineral estate owner also owns the support estate, that owner has the right to completely extract the minerals and, consequently, subside the surface property.²¹ In contrast, if the support estate is held by the surface estate owner, the mineral estate owner is required to leave as much of the mineral as necessary so the surface estate is unaffected by subsidence.²²

Under Pennsylvania law, property owners in fee simple can sever the ownership rights to the surface estate from the mineral, subsurface, and/or the support estate.²³ Ownership of the mineral estate includes the implied right to extract minerals, and mineral ownership on the same tract may be individually granted, such as coal, oil, and gas.²⁴ A grant of mineral estate ownership implies not only the right to extract the minerals from the subsurface but the right to use some necessary portion of the surface to exercise the right to extract minerals.²⁵ The mineral estate owner can use as much of the surface property as necessary in the exercise of their ownership, but “what is necessary and reasonable may be determined by reference to what is customary and is a question of fact.”²⁶ If a mineral estate owner can demonstrate their use or proposed use of the surface estate is both necessary and reasonable, a court will likely hold that the use is pertinent to the mineral ownership, even if the right is not expressly granted in the deed.²⁷

Wilkes-Barre Township School District v. Corgan, 403 Pa. 383, 170 A.2d 97 (1961).

⁹ See Walker v. Forcey, 393 Pa. 80, 80, 151 A.2d 601 (1959) (citing Lauderbach-Zerby Co. v. Lewis, 283 Pa. 250, 129 A. 83; Sheffield Water Co. v. Elk Tanning Co., 225 Pa. 614, 74 A. 742).

¹⁰ See *id.* at 80.

¹¹ Butler v. Charles Powers Estate ex rel. Warren, 620 Pa. 1, 22, 65 A.3d 885 (2013) (citing Gibson v. Tyson, 5 Watts 34, 41-42 (Pa. 1836)); see also Dunham & Shortt v. Kirkpatrick, 101 Pa. 36, 41 (1882).

¹² Dunham & Shortt, 101 Pa. at 41.

¹³ See generally Butler, 620 Pa. at 6 (citing Dunham, 101 Pa. at 41).

¹⁴ See Highland v. Commonwealth, 400 Pa. 261, 161 A.2d 390 (1960) (citing Dunham, 101 Pa. at 41); See also Silver v. Bush, 213 Pa. 195, 62 A. 832 (1906).

¹⁵ See Dunham & Shortt, 101 Pa. at 43.

¹⁶ *Id.*

¹⁷ See Butler, 620 Pa. at 25.

¹⁸ See Smith v. Glen Alden Coal Co., 347 Pa. 290, 296, 32 A.2d 227, 231 (1943).

¹⁹ Walker v. Forcey, 393 Pa. 80, 151 A.2d 601 (1959).

²⁰ *Id.*

²¹ 32 ENERGY & MIN. L. INST. 5 (2011).

²² *Id.*

²³ Commonwealth of Pa. Dep’t of Env’tl. Protection, LANDOWNERS AND OIL AND GAS LEASES IN PENNSYLVANIA, 5500-FS-DEP2834 (2007).

²⁴ *Id.*

²⁵ Baker v. Pittsburg, C. & W. R. Co., 219 Pa. 398, 404, 68 A. 1014 (1908).

²⁶ See Oberly v. H. C. Frick Coke Co., 262 Pa. 83, 83 104 A. 864 (1918) (coal mining operations).

²⁷ Richard T. Miller, *A Mineral Owner’s Implied Rights to Use Surface Property Owned by Others*, 32 ENERGY & MIN. L. INST. 5 (2011).

Under Pennsylvania law, the dominant estate is the mineral estate.²⁸ Despite due regard or accommodation, a mineral estate owner does not need to obtain the surface owner's permission to enter the surface property to mine for minerals.²⁹ A mineral estate owner can use as much surface land as reasonably necessary to extract minerals and is permitted to deplete an oil or gas reservoir beneath adjoining lands in the course of extracting oil and gas.³⁰ Even if the surface estate is owned by the government, "a subsurface owner's rights cannot be diminished," and a "regular" surface estate owner is not permitted to unilaterally impose unreasonable conditions on the subsurface estate owner.³¹

In Pennsylvania, gas is subject to the rule of capture. As a general rule in Pennsylvania, subterranean gas is owned by whoever has title to the property in which gas is resting.³² Similar to water and oil, gas belongs to the owner of the land and is part of it as long as it remains on that property. Once the gas escapes, the former owner's title to it vanishes.³³ If, for instance, the gas is present in coal and remains within the property of the coal owner, it is subject to that owner's control; if the gas migrates into a surrounding property, such as that of the owner with title to the property surrounding the coal, then that gas is under the control of that surrounding property's owner.³⁴

Within a severed coal estate, the chamber or space enclosing the coal remains the coal owners' as long as the coal has not been exhausted, and the estate has been neither terminated nor abandoned.³⁵ In cases of a right-of-way, however, the surface land is incorporeal and use is limited to the purpose specified in the grant.³⁶ The right to the space surrounding the coal is reflective of another implied right—for coal owners specifically—to use the passage on the surface estate opened for the removal of coal to transport coal from adjoining lands before all of the coal is removed from below.³⁷

²⁸ *Minard Run Oil Co. v. U.S. Forest Service*, 670 F.3d 236, 244 (3d Cir. 2011), as amended (Mar. 7, 2012) (citing *Belden & Blake Corp. v. DCNR*, 600 Pa. 559, 556, 969 A.2d 528 (2009)).

²⁹ See *Chartiers Block Coal Co. v. Mellon*, 152 Pa. 286, 296, 25 A. 597 (1893).

³⁰ *Minard Run Oil Co.*, 670 F.3d at 256.

³¹ See *Belden*, 600 Pa. at 567.

³² See *Westmoreland & Cambria Natural Gas Co. v. DeWitt*, 130 Pa. 235, 249, 18 A. 724 (1889).

³³ *Id.*

³⁴ See generally *U.S. Steel Corp. v. Hoge*, 503 Pa. 140, 156, 468 A.2d 1380 (1983) (Flaherty, J., dissenting).

³⁵ *Westerman v. Salt Mfg. Co.*, 260 Pa. 140, 144, 103 A. 539 (1918) (citing *Lillibridge v. Lackawanna Coal Co.*, 143 Pa. 293, 22 A. 1035 (1891)).

³⁶ *Weisfield v. Beale*, 231 Pa. 39, 79 A. 878 (1911); See also *Webber v. Vogel*, 159 Pa. 235, 244, 28 A. 226 (1893).

³⁷ *Id.* See also *Lillibridge v. Lackawanna Coal Co.*, 143 Pa. 293, 22 A. 1035 (1891); *Kormuth v. U.S. Steel Co.*, 379 Pa. 365, 108 A.2d 907 (1954).

Pore Space Ownership

No statutes or cases directly contemplate pore space ownership in Pennsylvania and no authority was found regarding pore space in the context of chemical disposal and carbon storage. However, a handful of cases involve situations that may indicate the Court's position on pore space ownership. In *U.S. Steel Corp. v. Hoge*, the Pennsylvania Supreme Court found that the holder of the coal mineral rights own coalbed gas.³⁸ The Court reasoned that, although coalbed gas is a "separate physical entit[y]" embedded in coal micropores, "such gas as is present in coal must necessarily belong to the owner of the coal."³⁹ It was dispositive to the Court that the deed specifically severed the rights to coal and gas.⁴⁰

Thirty-two years after *Hoge*, the Pennsylvania Superior Court held that because coalbed methane was not specifically reserved by the surface owner in the deed, but natural gas was reserved, that the surface owner had conveyed the right to collect coalbed methane.⁴¹ This holding could be expanded to find that a failure to explicitly reserve the pore space estate in a mineral deed transfers pore space ownership to the mineral estate holder. However, this holding may be limited to the facts surrounding coalbed methane.

On the other hand, when contemplating pore space in the context of gas storage, the Pennsylvania Superior Court found that an oil and gas lease does not, by itself, grant a right to store gas in the "cavernous spaces" below the ground.⁴² This holding may be limited to the facts of this case because the lease stated it was "for the sole and only purpose of drilling and operating for oil and gas."⁴³

Pennsylvania adheres to traditional notions of trespass, defining it as the "unprivileged, intentional intrusion upon land in possession of another."⁴⁴ Pennsylvania follows the ownership in place theory⁴⁵ but also the rule of capture, which is a common defense against subsurface trespass claims.⁴⁶ A plaintiff could overcome the rule of capture defense by proving the defendant

³⁸ *Hoge*, 503 Pa. at 144-46.

³⁹ *Id.*

⁴⁰ *Id.*

⁴¹ See *Kennedy v. Consol Energy Inc.*, 116 A.3d 626, 634 (Pa. Super. Ct. 2015).

⁴² See *Pomposini v. T.W. Phillips Gas & Oil Co.*, 580 A.2d 776, 779 (Pa. Super. Ct. 1990).

⁴³ *Id.* at 777.

⁴⁴ See *Graham Oil Co. v. BP Oil Co.*, 885 F. Supp. 716, 725 (W.D. Pa. 1994).

⁴⁵ *Hamilton v. Foster*, 116 A. 50, 52 (Pa. 1922) ("Oil and gas are minerals, and while in place are part of the land, and may be the subject of sale, separate and apart from the surface and from other minerals beneath it") (as referenced in *Briggs v. Southwestern Energy Production Company*, 224 A.3d 334, 336 (Pa.2020)).

⁴⁶ *Briggs*, 224 A.3d at 336.

intentionally drained the plaintiff's tract.⁴⁷ Pennsylvania also follows the discovery rule, which tolls the statute of limitations until the property owner discovered, or should have discovered through due diligence, the harm to the property, which is particularly relevant in subsurface trespass cases.⁴⁸ Pennsylvania's Supreme Court held that hydraulic fracturing techniques did not constitute a per se invasion on the plaintiff's property.⁴⁹ Further, the Court concluded that the burden of proof rests with the plaintiff (after directly pleading physical invasion trespass) to prove actual physical subsurface trespass, and that mere drainage of oil and gas via hydraulic fracturing does not satisfy the elements of trespass.⁵⁰

Water Rights

Pennsylvania adheres to the riparian rights doctrine for surface water.⁵¹ In 1940, in *Rothrauff v. Sinking Spring Water Co.*, the Supreme Court of Pennsylvania rejected the English rule and adopted the Rule of Reasonableness (or the American Rule) for groundwater.⁵²

Lithium Ownership and Extraction

Nothing was found regarding lithium extraction.

Classification of CO₂: Pollutant

Pennsylvania's regulatory landscape does not treat CO₂ as a commodity. The only evidence that CO₂ is not treated as a pollutant is a statute that enabled a siting study for a CO₂ sequestration network, but the study was to include the potential environmental and health impacts.⁵³ The statute only contemplates CO₂ storage, and it does not regulate CO₂ in the context of monetization or for future economic use.⁵⁴ The provisions, similar to the Pennsylvania Climate Control Act, focus on lowering CO₂ emissions.⁵⁵ Pennsylvania case law references CO₂ only in the context of environmental nuisance suits.⁵⁶

Pennsylvania has signaled its intent to join the Regional Greenhouse Gas Initiative ("RGGI"),⁵⁷ an interstate initiative of ten New England and Mid-Atlantic states to form a cap-and-trade organization for the market-based reduction of CO₂ emissions from the power sector. Significant in RGGI is a general prohibition of CCUS as a method of offsetting emissions against the cap in the system. The practical concern of this prohibition, from a utilization and enhanced recovery perspective, lies in the reduction of CO₂ supply for such projects, and related market disincentives for a power producer to engage in such projects.

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

Title 58, Chapter 7 of Pennsylvania's statutes contains Pennsylvania oil and gas conservation laws.⁵⁸ The Act does not apply to wells that do not penetrate the Onondaga horizon, or in those areas that Onondaga horizon is nearer to the surface than 3800 feet, or any wells that do not exceed a depth of 3800 feet.⁵⁹ In addition, wells that inject gas into or withdraw gas from gas storage reservoirs are not covered by the Act.⁶⁰ Finally, the Act exempts wells commenced prior to July 25, 1961.⁶¹ The Pennsylvania Department of Environmental Protection ("DEP") is responsible for the administration and enforcement of the conservation laws in Pennsylvania, which entails prohibiting waste of oil and gas, approving drilling permits, and establishing well spacing and drilling units under the applicable statutory provisions.⁶² The Pennsylvania conservation laws grant the DEP authority to establish procedural rules with an underlying requirement of notice and comment prior to the DEP issuing an order.⁶³ The DEP is authorized to conduct hearings and investigations and can order fines or injunctive relief for violations of conservation law.⁶⁴

After one well has been drilled and the well falls under the authority covered by this Act, a well operator or interest holder may apply to the DEP for an order establishing well spacing and drilling units of a specified

⁴⁷ *Barnard v. Monongahela Gas Co.*, 65 A. 801, 802 (Pa. 1907).

⁴⁸ *Pocono Int'l Raceway, Inc. v. Pocono Produce, Inc.*, 468 A.2d 468, 471 (1983).

⁴⁹ *Briggs*, 224 A.3d at 348-49.

⁵⁰ *Id.* at 349.

⁵¹ *See* *Lord v. Meadville Water Co.*, 135 Pa. 122, 19 A. 1007 (1890); *Chambers v. Furry*, 1 Yeates 167 (Pa. 1792); *Alburger v. Philadelphia Elec. Co.*, 112 Pa. Commw. 441, 535 A.2d 729 (1988).

⁵² *Rothrauff v. Sinking Spring Water Co.*, 339 Pa. 129, 14 A.2d 87 (Pa. 1940).

⁵³ 66 PA. STAT. AND CONS. STAT. ANN. § 2815 (West 2008).

⁵⁴ *Id.*

⁵⁵ *See generally* 71 PA. STAT. AND CONS. STAT. ANN. § 1362.3 (West 2014); 71 PA. STAT. AND CONS. STAT. ANN. § 1361.7 (West 2008).

⁵⁶ *Com. v. Queen Coal Co.*, 2 Pa. Cmmw. 1, 4 (Pa. Commw. Ct. 1971).

⁵⁷ GOVERNOR WOLF TAKES EXECUTIVE ACTION TO COMBAT CLIMATE CHANGE, CARBON EMISSIONS (2019), <https://www.governor.pa.gov/newsroom/governor-wolf-takes-executive-action-to-combat-climate-change-carbon-emissions/>.

⁵⁸ *See* 58 PA. STAT. AND CONS. STAT. ANN. § 401 (West 2020).

⁵⁹ 58 PA. STAT. AND CONS. STAT. ANN. § 403(b)(1) (West 2020).

⁶⁰ 58 PA. STAT. AND CONS. STAT. ANN. § 403(b)(3) (West 2020).

⁶¹ 58 PA. STAT. AND CONS. STAT. ANN. § 403(b)(2) (West 2020).

⁶² 58 PA. STAT. AND CONS. STAT. ANN. §§ 404-409 (West 2020).

⁶³ 58 PA. STAT. AND CONS. STAT. ANN. § 410 (West 2020).

⁶⁴ 58 PA. STAT. AND CONS. STAT. ANN. §§ 411 to 414 (West 2020).

size for each pool.⁶⁵ The separate interest holders of adjoining tracts may voluntarily combine their tracts and/or interests for efficient development and share in the production of the oil and gas underlying the tracts.⁶⁶ In the absence of a voluntary unitization agreement, the DEP, upon the application from an operator with an interest in the unit, must order the integration of all tracts or interests in the spacing unit for the development, operation, and shares of production between interest owners.⁶⁷ In Pennsylvania, no statutory minimum acreage control requirement exists for an operator to forcibly pool the interests in a spacing unit.⁶⁸ Notice and comment for all interested parties is required before a unitization order takes effect.⁶⁹ Unknown “of record” interest holders may be notified by publication for two weeks prior to the hearing, but defective notice does not invalidate order, and an unknown interest holder of record does not forfeit interest if not successfully located and notified.⁷⁰

This law only applies to wells deeper than the Onondaga horizon. Because of this restriction on the applicability of the forced pooling provision in the conservation laws, forced pooling in Pennsylvania is rarely used, mainly because it does not apply to most Marcellus Shale operations.⁷¹ A more recent law the Oil

“In Pennsylvania, no statutory minimum acreage control requirement exists for an operator to forcibly pool the interests in a spacing unit.”

⁶⁵ See generally 58 PA. STAT. AND CONS. STAT. ANN. § 407 (West 2020).

⁶⁶ See generally 58 PA. STAT. AND CONS. STAT. ANN. § 408(a) (West 2020).

⁶⁷ *Id.*

⁶⁸ Frank Sylvester & Robert W. Malmshemer, *Oil and Gas Spacing and Forced Pooling Requirements: How States Balance Energy Development and Landowner Rights*, 40 UDTNLR 47, 58 (2015) (discussing the minimum acreage control requirements for force pooling, and using Pennsylvania as an example of one of the nine states that do not specify minimum acreage control requirements in their statutes or regulations).

⁶⁹ See generally 58 PA. STAT. AND CONS. STAT. ANN. § 408(a) (West 2020).

⁷⁰ *Id.*

⁷¹ *Id.* at 53.

and Gas Lease Act, passed in 2013, allows an operator to develop multiple contiguous leases jointly and provides for apportionment of production among the multiple leases in the absence of agreement by all affected royalty owners.⁷²

An operator conducting EOR methods or underground storage must file a copy of a map and certain statutorily required data if the gas well operation is within a specified distance/proximity to an operating coal mine with a “coal seam that extends over the storage reservoir or reservoir protective area.”⁷³ The person filing the map has the burden of proving accuracy.⁷⁴ Other well-reporting requirements mandate an operator to file an annual report regarding production per well and the status of each well, specifying any well changes between annual reports.⁷⁵ Operators must maintain records of each well drilled or altered, and once a well is drilled, an initial report must be filed with statutorily required information.⁷⁶ The statute mandating reporting for unconventional wells requires a report every 30 days, specifying the status of the well and the amount of production.⁷⁷

Pennsylvania has no observed induced seismic events,⁷⁸ and no state regulation pertains directly to induced seismicity. However, state permit applications must complete EPA permitting, which requires a report on fault lines in proximity to the injection well area and includes an opinion on whether any seismic risk exists.⁷⁹

State Environmental Laws

In Pennsylvania, the EPA directly implements the UIC program, including classes I-VI.⁸⁰ As such, interested operations must obtain permission from the federal government through the EPA, rather than state or local

⁷² 58 PA. STAT. AND CONS. STAT. ANN. § 34.1 (West 2020) (“Where an operator has the right to develop multiple contiguous leases separately, the operator may develop those leases jointly by horizontal drilling unless expressly prohibited by a lease. In determining the royalty where multiple contiguous leases are developed, in the absence of an agreement by all affected royalty owners, the production shall be allocated to each lease in such proportion as the operator reasonably determines to be attributable to each lease.”).

⁷³ 58 PA. STAT. AND CONS. STAT. ANN. § 3231(a) (West 2020).

⁷⁴ 58 PA. STAT. AND CONS. STAT. ANN. § 3236(b)(2) (West 2020).

⁷⁵ 58 PA. STAT. AND CONS. STAT. ANN. § 3222(a) (West 2020).

⁷⁶ 58 PA. STAT. AND CONS. STAT. ANN. § 3222(b) (West 2020).

⁷⁷ 58 PA. STAT. AND CONS. STAT. ANN. § 1003 (West 2020).

⁷⁸ PENNSYLVANIA DEP’T OF ENVTL. PROT., INJECTION WELLS FOR ENHANCED RECOVERY AND DISPOSAL, <http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=1419032&DocName=INJECTION%20WELLS%20FOR%20ENHANCED%20RECOVERY%20AND%20DISPOSAL.PDF%20%20%3cspan%20style%3D%22color%3b%22%3e%3c%2011/15/2020>.

⁷⁹ *Id.*

⁸⁰ MARY TIEMANN & ADAM VANN, *HYDRAULIC FRACTURING AND SAFE DRINKING WATER ACT REGULATORY ISSUES* (Congressional Research Service 2015).

permission. For the EPA to delegate primacy to the state, the state program must meet “EPA requirements promulgated under Section 1421” and prohibit “underground injection that is not authorized by permit or rule.”⁸¹ Currently, 24 companies and corporations in Pennsylvania hold UIC permits.⁸²

Injection wells for EOR and disposal are governed primarily by Title 25 Chapters 78 and 91 of the Pennsylvania Code. Permit requirements for injection wells and EOR operations are contained within 25 Pa. Code Section 78.18. For unconventional wells, permit application requirements are contained within 25 Pa. Code Section 78a.15. An applicant must show that a disposal injection well does not prejudice the public interest and does not pose a substantial threat of pollution to the surrounding water table; similarly, approval of a disposal injection well does not relieve the applicant of liability resulting from subsequent pollution.⁸³ If within a specified proximity to a watercourse or exceptional value body of water, the applicant must have a water protection and pollution mitigation plan.⁸⁴ The 2009 Carbon Sequestration Network Assessment states that any permit for a CO₂ injection well must follow all “regulations for drilling and completing an oil or gas well.”⁸⁵

A landowner or an affected party who believes that a well or drilling operation polluted or degraded their water supply may request an investigation by the DEP, and the DEP must decide on the investigation within 45 days of receiving the notification.⁸⁶ If the DEP finds a degraded water supply, it presumes the well operator is responsible if the water supply is within 1,000 feet of a well and the pollution occurred within six months after completion of drilling or alteration to a well.⁸⁷ In the case of an unconventional well, the operator is presumed responsible if the water supply is within 2,500 feet of the well and the pollution occurred within 12 months of drilling, stimulation, or alteration of the well.⁸⁸ The operator may rebut this presumption.⁸⁹ If the DEP decides that the operator is responsible for the pollution, the operator is responsible for restoring or replacing the water

supply to such a point that the water quality meets the standards of the Pennsylvania Safe Drinking Water Act and is in an adequate and reliable quantity.⁹⁰

Well development pipelines that are used to transport fluids other than fresh groundwater, surface water, and water from water purveyors or approved sources must have shut off valves, check valves, or other methods of segmenting the pipeline to prevent the discharge of more than 1,000 barrels of fluid.⁹¹ The valves are placed at designated intervals, to be determined by the pipeline diameter.⁹² This specific provision specifically applies only to pipelines carrying fluids.⁹³

Pennsylvania includes 9,218 interstate and 1,253 intrastate gas transmission miles, and 3,024 interstate and 98 intrastate hazardous liquid miles.⁹⁴ No laws or regulations in Pennsylvania that specifically regulate CCS or apply to the siting, construction, operation, and closure of the pipelines and sequestration wells that will constitute the CCS network. While no CO₂ pipelines currently exist in Pennsylvania, an extensive network for natural gas and refined petroleum products lies within the state. Many of the major CO₂ sources in Pennsylvania are located along existing pipeline rights-of-way.⁹⁵

Industrial Siting Requirements

Our research did not locate any relevant industrial siting requirements. However, Pennsylvania addresses some industrial site issues within the Industrial Sites Environmental Assessment Act.⁹⁶ Under the Act, the Department of Community and Economic Development of the Commonwealth is able to make grants and loans to authorities for conducting environmental assessments of industrial sites.⁹⁷

Pipeline Regulation

Through certification by OPS, Pennsylvania inspects and enforces the pipeline safety regulations for intrastate gas and hazardous liquid pipeline operators in the state. The Gas Pipeline Safety Section of the Engineering Division of the Public Service Commission

⁸¹ *Id.*

⁸² ENVTL. PROTECTION AGENCY, PENNSYLVANIA UNDERGROUND INJECTION CONTROL (UIC) PERMITS, <https://www.epa.gov/uic/pennsylvania-underground-injection-control-uic-permits>.

⁸³ 25 PA. CODE § 91.51(b)(3)-(c) (2020).

⁸⁴ 25 PA. CODE § 78a.15 (2020).

⁸⁵ PENNSYLVANIA DEP’T OF CONSERVATION AND NAT. RES., GEOLOGIC CARBON SEQUESTRATION OPPORTUNITIES IN PENNSYLVANIA 35 (2009), http://www.docs.dcnr.pa.gov/cs/groups/public/documents/document/dcnr_20033315.pdf.

⁸⁶ 58 PA. STAT. AND CONS. STAT. ANN. § 3218(a) (West 2020).

⁸⁷ 58 PA. STAT. AND CONS. ANN. § 3218(c)(1)-(2) (West 2020).

⁸⁸ *Id.*

⁸⁹ 58 PA. STAT. AND CONS. ANN. § 3218(d)(1)-(2) (West 2020).

⁹⁰ 25 PA. CODE § 78.51(d) (2020).

⁹¹ 25 PA. CODE § 78a.68b(e) (2020).

⁹² *Id.*

⁹³ *Id.*

⁹⁴ U.S. DEP’T OF TRANSP., PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, GAS TRANSMISSION AND HAZARDOUS LIQUID PIPELINE SAFETY PROGRAMS PARTICIPATING STATES IN THE FEDERAL/STATE COOPERATIVE PARTNERSHIP, <https://www.npms.phmsa.dot.gov/Documents/CoopAgreementsMap.pdf>.

⁹⁵ TETRA TECH, PA. DEP’T OF CONSERVATION AND NAT. RES., ASSESSMENT OF RISK, LEGAL ISSUES, AND INSURANCE FOR GEOLOGIC CARBON SEQUESTRATION IN PENNSYLVANIA 4-20 (2009).

⁹⁶ 35 PA. STAT. AND CONS. STAT. ANN. § 6028.1 (West 2020).

⁹⁷ 35 PA. STAT. AND CONS. STAT. ANN. § 6028.2 (West 2020).

performs this work.⁹⁸ In Pennsylvania, under the Gas and Hazardous Liquids Pipelines Act, the safety standards and regulations for pipeline operators are the federal pipeline safety laws as implemented in 49 C.F.R. Subtitle B Ch. I Subch. D.⁹⁹ The Pennsylvania Public Utility Commission has general administrative authority to supervise and regulate all pipeline operators within the state consistent with Federal pipeline safety laws.¹⁰⁰ By letter dated January 7, 2020, OPS notified the state that its enforcement of Pennsylvania’s excavation damage prevention law was “adequate.”¹⁰¹

Local Regulation

State regulation of oil and gas development largely preempts local regulation of oil and gas development. While mining operations and wells may not be completely excluded from a particular locality, municipalities are permitted through zoning to regulate the location of wells within their boundaries. Additionally, local governments have the power to impose a fee on each well within their jurisdiction¹⁰² and to impose setback requirements on drilling operations.¹⁰³

In 2013, a statute that attempted to prohibit any local regulation of oil and gas and sought uniformity among local zoning ordinances was struck down, maintaining the local government’s ability to utilize individualized zoning measures. The court reasoned that local authorities have a better understanding of the consequences of oil and gas actions within their locality and can better enforce the input of the public.¹⁰⁴

Tribal Land

Our research did not reveal the presence of any tribal land in Pennsylvania.

Eminent Domain:

Pennsylvania’s Eminent Domain Code contains the applicable provisions regarding condemnation of property for a pipeline right-of-way.¹⁰⁵ However, to utilize these provisions, the oil and gas company must be a public utility corporation (“PUC”). If the oil and gas company is a PUC, the power of eminent domain may be used to condemn property for the transportation of artificial or natural gas, petroleum, or petroleum products, subject to certain requirements.¹⁰⁶ The statute does not specifically mention carbon dioxide pipelines, creating uncertainty as to its applicability. The PUC may only exercise its power of eminent domain when a certificate of public convenience has been issued.¹⁰⁷ Before a public utility can construct a pipeline for artificial or natural gas and/or petroleum, “the service to be furnished by the corporation through the exercise of those powers is necessary or proper for the service, accommodation, convenience or safety of the public.”¹⁰⁸ PUCs and natural gas companies may exercise the power of eminent domain only for public use.

A public utility may also condemn land for an easement or right-of-way for pipelines under Pennsylvania’s Business Corporation Law (“Associations Code”), 15 Pa. Stat. Section 1511(g)(2). The Association code provides that a corporation with the power of eminent domain for electric, gas, oil or petroleum product lines used directly or indirectly to serve the public interest may elect to proceed in the sections prescribed in lieu of the procedures in the Eminent Domain Code.¹⁰⁹ The utility has the option of proceeding under the provisions of the Eminent Domain Code or of following the procedures set forth in the Association’s Code. Although courts have not considered the question, because carbon dioxide pipelines were likely not considered when the statute was drafted, the statute may not apply to carbon dioxide pipelines.

Under 15 Pa. Stat. Section 1511(a)-(b), a public utility has the right to take, occupy, and condemn property for the transportation of artificial or natural gas, electricity, petroleum or petroleum products or water, or any combination of such substances, for the public.¹¹⁰ Further, municipal authorities have the power to acquire water and water rights as the authority deems necessary for public improvements, utilities, and services.¹¹¹ The municipality

⁹⁸ U.S. DEP’T OF TRANSP., REGULATORY FACT SHEET: PENNSYLVANIA, https://primis.phmsa.dot.gov/comm/FactSheets/States/PA_State_PL_Safety_Regulatory_Fact_Sheet.htm.

⁹⁹ 58 PA. STAT. AND CONS. STAT. ANN. § 801.302.

¹⁰⁰ 58 PA. STAT. AND CONS. STAT. ANN. § 801.501 (West 2020).

¹⁰¹ Letter from Massoud Tahamtani, Deputy Associate Administrator, Policy and Programs, Office of Pipeline Safety, to Gladys Brown-Dutrieuille, Chairman, Pennsylvania Public Utility Commission (Jan. 7, 2020) (on file with U.S. Dep’t of Transportation), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-05/Signed-PA-Notice-of-Adequacy-Letter-for-2019-PHP-20-0100.pdf>.

¹⁰² Act No. 13 of Feb. 14, 2012, P.L. 87, *eff.* immediately (in part) and Apr. 16, 2012 (in part), 58 Pa.C.S. §§ 2301–3504.

¹⁰³ *See* Huntley & Huntley, Inc. v. Borough Council of Borough of Oakmont, 600 Pa. 207 (2009).

¹⁰⁴ *Robinson Twp., Washington Cty. v. Com.*, 623 Pa. 564 (2013).

¹⁰⁵ 26 Pa. Stat. Section 101 et seq.

¹⁰⁶ 15 PA. STAT. AND CONS. STAT. ANN. § 1511(a)(2) (West 2020).

¹⁰⁷ *See* 66 PA. STAT. AND CONS. STAT. ANN. § 1101 (West 2020) (organization of public utilities and beginning of service); 66 PA. STAT. AND CONS. STAT. ANN. § 1104 (certain appropriations prohibited) (West 2020).

¹⁰⁸ 15 PA. STAT. AND CONS. STAT. ANN. § 1511(c) (West 2020).

¹⁰⁹ *See* 15 PA. STAT. AND CONS. STAT. ANN. § 1511(g)(2) (West 2020).

¹¹⁰ 15 PA. STAT. AND CONS. STAT. ANN. § 1511(a)-(b) (West 2020).

¹¹¹ 53 PA. STAT. AND CONS. STAT. ANN. § 5615(a)(1) (West 2020).

may exercise this authority within the municipality or outside of the municipality.¹¹²

A county water supply authority may also acquire interests necessary to the provision and protection of its water supply via eminent domain.¹¹³ 16 Pa. Stat. Section 12907 defines when county water supply authorities may acquire subsurface rights through eminent domain.¹¹⁴ Pennsylvania law recognizes that there may be three separate estates in land: the surface, the right of support, and the subsurface mineral rights.¹¹⁵ A condemnation of a tract of land must be considered a condemnation of all estates in the land, unless evidence suggests that the condemning authority knows of the existence of a separate mineral estate owner.¹¹⁶ Interestingly, where the Pennsylvania Department of Transportation exercises its power of eminent domain and appropriates land for a highway right-of-way, it also appropriates a subsurface stratum of that land so far as necessary to support the surface of the highway.¹¹⁷

In regards to geologic storage, 58 Pa. Stat. Section 3241 covers the appropriation of interest in real property “located in a storage reservoir or reservoir protective area for injection, storage and removal from storage of natural gas or manufactured gas in a stratum which is or previously has been commercially productive of natural gas.”¹¹⁸ However, this statute has been held unconstitutional.¹¹⁹

Geologic CO₂ Storage Regulation and Incremental Storage:

In western Pennsylvania, several potential storage reservoirs have been identified with sufficient capacity to inject CO₂ emissions over a 30- to 50-year period and permanently store the CO₂.¹²⁰ Underground gas storage is governed by 58 Pa. Stat. Section 3231 et seq. and 25 Pa. Code Section 78.401 et seq. There seems to be no mention of incidental storage in the case law or statutory code. In Pennsylvania, all injection wells are subject to state permitting procedures¹²¹ and EPA federal regulations,¹²² but no mention of quantifying incidental storage was yet found in any legal precedent. According to the Marcellus Shale Committee, “at least 50% of injectable CO₂ is incapable of being recovered for reuse and remains in the underground formation.”¹²³ Pennsylvania is 66 Pa. Stat. Section 2815 mandates an assessment for the viability of underground carbon sequestration in Pennsylvania and establishes a carbon sequestration network of Commonwealth owned lands viable for carbon sequestration. The assessment was published in 2009.¹²⁴

Pennsylvania statutes do not address ownership – title and liability. House Bill 80, introduced in 2009, which provided that title and liabilities would transfer from the generator of the CO₂ to the storage facility operator, with assumed liability of a storage facility via a taxpayer-funded liability fund by the Commonwealth.¹²⁵ However, House Bill 80 did not pass.¹²⁶

¹¹² 53 PA. STAT. AND CONS. STAT. ANN. § 5615(b) (West 2020).

¹¹³ 16 PA. STAT. AND CONS. STAT. ANN. § 12907 (West 2020) (emphasis added).

¹¹⁴ *Id.*

¹¹⁵ See *Pennsylvania Bank & Trust Co., Youngsville Branch v. Dickey*, 335 A.2d 483, 232 Pa. Super. 224 (1975).

¹¹⁶ *Captline v. Allegheny County*, 459 A.2d 1298 (1983).

¹¹⁷ *Brownfield v. Pennsylvania, Dep’t of Trans.*, 364 A.2d 767 (1976).

¹¹⁸ 58 PA. STAT. AND CONS. STAT. ANN. § 3241.

¹¹⁹ See *Robinson Township v. Commonwealth*, 147 A.3d 536, 637 Pa. 239 (2016).

¹²⁰ TETRA TECH, *supra* note 99, at 4-20.

¹²¹ 25 PA. CODE §§ 78.18 & 78a.15.

¹²² 40 C.F.R. §§ 146.21-.25.

¹²³ PENNSYLVANIA DEP’T OF CONSERVATION AND NAT. RES., ASSESSMENT OF RISK, LEGAL ISSUES, AND INSURANCE FOR GEOLOGIC CARBON SEQUESTRATION IN PENNSYLVANIA 3.2.1.4 (2009), http://www.docs.dcnr.pa.gov/cs/groups/public/documents/document/dcnr_20033316.pdf.

¹²⁴ PENNSYLVANIA DEP’T OF CONSERVATION AND NAT. RES., GEOLOGIC CARBON SEQUESTRATION OPPORTUNITIES IN PENNSYLVANIA (2009), http://www.docs.dcnr.pa.gov/cs/groups/public/documents/document/dcnr_20033315.pdf.

¹²⁵ PENNSYLVANIA DEP’T OF CONSERVATION AND NAT. RES., ASSESSMENT OF RISK, LEGAL ISSUES, AND INSURANCE FOR GEOLOGIC CARBON SEQUESTRATION IN PENNSYLVANIA 3.4 (2009), http://www.docs.dcnr.pa.gov/cs/groups/public/documents/document/dcnr_20033316.pdf.

¹²⁶ *Id.*

TENNESSEE

Executive Summary

Tennessee enacted a relatively limited statutory framework specific to CO₂ transport and storage. Pore space, mineral, and surface interests are severable and may exist as separate estates. While no statutory condemnation authority specifically addresses CO₂ pipelines, the Attorney General of Tennessee opined that current statutes authorize a pipeline corporation to condemn an easement for pipelines that will be used for the transportation and distribution of carbon dioxide specifically. Tennessee oil and gas regulations include stringent pooling requirements, though there is no equivalent requirement for geologic storage.

Background:

Tennessee consists of approximately 26,380,800 acres. Of that total, 4.14% is federal land, while 6.53% is owned by the state. There are no tribal lands in Tennessee.

The Supreme Court is the highest court in the state judicial system. Two intermediate appellate courts exist. Trial courts include Chancery, Criminal, Circuit, and Probate Courts. The fourth level of courts in the state are the courts of limited jurisdiction, which include General Sessions, Juvenile, and Municipal Courts.

A General Sessions Court serves each county. Jurisdiction differs between counties, but the courts hear civil cases limited to a certain monetary amount. Municipal Courts have authority over cases involving violations of city ordinances. Circuit Courts hear trials in civil and criminal matters, as well as appeals from courts of limited jurisdiction. Chancery Courts are courts of equity and hear certain civil cases not involving demands for money damages. Finally, Probate Courts preside over probate and administration of estates and handle conservatorships and guardianships.

CO₂-EOR in Tennessee:

Tennessee has no oil production at this time and has minimal oil production historically.¹ Tennessee produces natural gas, ranked 24th in the country, but the aggregate amounts are low, at approximately 0.01% of US total production.² Interestingly, Tennessee is home to one of the first CO₂-enhanced gas recovery projects in the Appalachian Basin in tight shales, injecting 510 tons

¹ U.S. ENERGY INFO. ADMIN., PETROLEUM & OTHER LIQUIDS, <https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPTN2&f=M> (last visited Sept. 15, 2020).

² U.S. ENERGY INFO. ADMIN., TENNESSEE, <https://www.eia.gov/state/rankings/?sid=TN#/series/47> (last visited Sept. 15, 2020).



of CO₂ into the Chattanooga Shale, and producing 6,756 Mcf of hydrocarbons.³

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Ownership

Tennessee courts interpret contracts according to the intention of the parties.⁴ To determine intent, the court may review the situation of the parties, the parties' motive, and what is set to be affected by the contract.⁵ Reservations and grants are construed most strictly against the grantor.⁶ Each construction must be decided upon the language of the grant or reservation, the surrounding circumstances, and the intent of the grantor, if known.⁷

Because the word "mineral" on its own can be defined narrowly or broadly, Tennessee law prohibits the use of arbitrary definitions when referring to mineral substances.⁸ Tennessee law considers petroleum oil,⁹ natural gas,¹⁰ and in a technical sense, limestone,¹¹ as minerals within a reservation by deed of "all mines, minerals, and metals in and under the land."¹² When including petroleum and natural gas within the term

³ Louk, K., Ripepi, N., Luxbacher, K., Gilliland, E., Tang, X., Keles, C., & Michael, K., *Monitoring CO₂ storage and enhanced gas recovery in unconventional shale reservoirs: Results from the Morgan County, Tennessee injection test*, J. OF NAT. GAS SCI. AND ENG'G 11-25, 45 (2017).

⁴ Nunnally v. Warner Iron Co., 94 Tenn. 282, 29 S.W. 124, 127 (1895). See also Doochin v. Rackley, 610 S.W.2d 715, 719 (Tenn. 1981).

⁵ Nunnally, 29 S.W. at 127.

⁶ Campbell v. Tennessee Coal, Iron & R. Co., 150 Tenn. 423, 265 S.W. 674, 676-77 (1924).

⁷ *Id.* at 677.

⁸ *Id.*

⁹ Murray v. Allard, 100 Tenn. 100, 43 S.W. 355, 359 (1897).

¹⁰ *Id.* at 359-60.

¹¹ Campbell, 265 S.W. at 677.

¹² Murray, 43 S.W. at 359.

“minerals,” the Tennessee Supreme Court explicitly declined to follow Pennsylvania’s “Dunham Rule,” which holds the contrary.¹³

Tennessee’s Code defines “mineral interest” as the interest created by an instrument, conveying an interest of any kind in coal, oil and gas, and other minerals.¹⁴ A contract conveying the exclusive right to mine minerals constitutes a corporeal interest in the land that can be assigned, divided, or dealt with like any other interest.¹⁵ When a specific term is used to convey a mineral, only that mineral will pass, and the other minerals will remain within the property of the owner in fee.¹⁶ Following the removal of a mineral conveyed, the owner of that mineral no longer has any other rights in the land, which then belongs to the owner of the surface and fee.¹⁷

Oil and gas leases convey “only a contingent right of possession of the land for the purposes of exploration.”¹⁸ However, if oil or gas is found during exploration, the right to retain possession for the purpose of producing becomes a vested right under the terms of the lease.¹⁹ If the oil or gas is reduced to possession, title as personalty becomes vested in the lessee.²⁰ Because the amount of consideration depends on the amount of mineral physically extracted, mining and mineral leases in Tennessee are considered “double-faceted,” acting as both a lease and a sale.²¹

Oil and gas leases are construed most favorably to development and most strongly against the lessee.²² Courts imply a number of covenants into an oil and gas lease, including covenants: “(1) to drill an exploratory well; (2) to drill off-set wells; (3) to drill additional wells during and after the exploratory period; and (4) to diligently operate and market.”²³ Provisions in oil and gas leases, such as no-termination or forfeiture clauses, seek to provide some relief from the implied covenants to the lessee.²⁴ A no-termination provision prevents the forfeiture of the lease until the lessee is determined to

have breached an implied covenant and given a reasonable time to remedy the breach.²⁵ However, the validity of no-termination and similar clauses in an oil and gas lease is “questionable.”²⁶ The Tennessee Supreme Court found a no-termination clause to be inapplicable to implied covenants requiring the lessee to drill, to pay delay rental, or to be in production in paying quantities by a certain date.²⁷ Therefore, the lease in that case terminated when the lessee failed to carry out those actions.²⁸

Split Estates

Tennessee permits the separation of strata, and a deed in fee simple for each particular deposit or stratum may legally exist.²⁹ The owner of a fee simple estate may convey the land to one person, and the minerals individually to another (or others).³⁰ While the owner in fee simple may retain the surface, each stratum becomes “a subject of taxation, incumbrance, levy, or sale,” just like the surface.³¹ Upon the possession of the surface to the lessor in a mining lease for all purposes other than mining, such possession has been held not adverse to the lessee.³²

Distinct estates are created in the severance of the mineral interest from the surface estate. In an adverse possession case, the Supreme Court of Tennessee held that once the estates are split, possession of the surface by the grantor fails to show possession of the mineral interest.³³ The grantor of minerals conveys the right to obtain access to them through the surface by implication of law.³⁴ Accordingly, acts of possession required for the surface versus those for minerals differ, with the latter requiring some form of mining or related activities.³⁵ The right to own and take a mineral upon a tract of land is confined to the ownership and taking alone and cannot interfere with the balance of the land as held by the owner

²⁵ Waddle, 551 S.W.2d at 327.

²⁶ *Id.*

²⁷ *Id.*

²⁸ *Id.*

²⁹ Northcut v. Church, 135 Tenn. 541, 188 S.W. 220, 223 (1916).

³⁰ *Id.* at 221. See generally Westmoreland & Cambria Nat. Gas Co. v. De Witt, 130 Pa. 235, 249-50, 18 A. 724, 725 (1889); Gordon v. Park, 202 Mo. 236, 100 S.W. 621 (1907); Wallace v. Elm Grove Coal Co., 58 W. Va. 449, 52 S.E. 485 (1905); Louisville & N.R. Co. v. Massey, 136 Ala. 156, 33 So. 896 (1903); Catlin Coal Co. v. Lloyd, 176 Ill. 275, 52 N.E. 144 (1898).

³¹ *Id.*

³² Charleston, S.C. Mining & Mfg. Co. v. Am. Agr. Chem. Co., 126 Tenn. 18, 150 S.W. 1143, 1145 (1911).

³³ Northcut, 188 S.W. at 223.

³⁴ *Id.* See also Reliance Coal & Coke Co. v. Kentucky Coal & Coke Co., 93 Tenn. 191, 23 S.W. 1095, 1097 (1893) (holding a reservation in the lease as to “roads, railways, water ways, side tracks, and other structures” related to surface ways for the purpose of ingress and egress to the surface of the adjacent land, and did not embrace underground entries through complainant’s leased land.).

³⁵ Northcut at 223 (emphasis added).

¹³ *Id.* at 359-60 (citing *Dunham v. Kirkpatrick*, 101 Pa. 36 (1882)).

¹⁴ TENN. CODE ANN. § 66-5-108(b)(1) (West 2020).

¹⁵ *Bates v. Georgia Fertilizer Co.*, 144 Tenn. 32, 229 S.W. 153, 157 (1921) (citing *Stanton v. Herbert & Sons*, 141 Tenn. 447, 211 S.W. 353. (1919)).

¹⁶ *McBurney v. Glenmary Coal & Coke Co.*, 121 Tenn. 275, 118 S.W. 694, 699 (1909), overruled in part by *Northcut v. Church*, 135 Tenn. 541, 188 S.W. 220 (1916).

¹⁷ *Id.* at 698.

¹⁸ *Morris v. Messer*, 156 Tenn. 54, 299 S.W. 782, 783 (1927).

¹⁹ *Id.*

²⁰ *Id.*

²¹ *Id.*

²² *Waddle v. Lucky Strike Oil Co.*, 551 S.W.2d 323, 326 (Tenn. 1977).

²³ *Waddle*, 551 S.W.2d at 327 (citing M. Merrill, *Covenants Implied in Oil and Gas Leases*, (2nd ed. 1940); 4 Kulp, *Oil and Gas Rights* (1954) ss 10.66-10.71).

²⁴ *Id.*

in rights of dominion and possession.³⁶ Hence, possession under such a right can only extend to the amount of land necessary and proper for such a taking.³⁷ This is consistent with the rights of possession and ownership held by the owner of the balance of the estate.³⁸ Similar to Pennsylvania,³⁹ the rights of possession and ownership held by the owner of the balance of the estate include a right to surface support.⁴⁰ An owner who alienates the mineral rights but reserves the surface is not presumed to have parted with the right to surface support.⁴¹ Therefore, the lessee or grantee of the mineral rights is entitled only to so much of the mineral as he or she can get while leaving reasonable support for the surface.⁴² Tennessee's Oil and Gas Surface Owners Compensation Act of 1984,⁴³ was enacted for the purpose of establishing equal rights to surface use and mineral development, as well as providing "constitutionally permissible protection and compensation to surface owners of land on which oil and gas wells are drilled..."⁴⁴ This Act obligates an oil and gas developer to compensate the surface owner for lost income, market value of damaged crops, damage to a water supply, costs to repair personal property, and diminution in property value.⁴⁵ Although not providing the notice and procedural requirements of the split estate statutes in other states, in the absence of a voluntary agreement the act allows the surface owner to compel a binding arbitration process to determine the amount of compensation to be awarded.⁴⁶ In contrast to the Kentucky statute, Tennessee's Surface Owners Compensation Act specifically provides that it does not diminish the common law remedies available to a surface owner or any other person against the developer for wrongful use of the surface.⁴⁷

Pore Space Ownership

Pore space ownership is largely undecided in Tennessee. Some evidence suggests that, at least within the context of gas storage, surface owners own the pore space. One case arguably suggests that the mineral estate and storage rights comprise separate estates and each

requires an explicit conveyance.⁴⁸ However, the regulatory code that the opinion rested on has been repealed and amended.⁴⁹ The most pertinent regulatory section, while amended and re-named, substantially survives.⁵⁰ That section requires that any person using subterranean reservoirs for gas storage must obtain written consent from "all owners in such underground reservoir."⁵¹ The regulation fails to elaborate on whether "owners" would encompass surface owners, mineral estate holders, or both. This regulation could be construed in such a way to create ownership in pore space, separate from the mineral estate. In summary, pore space ownership in Tennessee remains uncertain.

Tennessee Code Section 66-7-103 provides some clarity.⁵² Section 66-7-103 states that unless a mineral rights lease is being used commercially, the lease expires after ten years.⁵³ A provision provides the statute does not apply to "conveyance[s] or other instrument[s] insofar as it may convey underground natural gas storage rights."⁵⁴ This specific distinction between the "gas" and the "gas storage" estates implies that both estates must be conveyed, and that conveyance of one does not include the other. The surface owner retains the storage rights until expressly conveyed. State law does not address pore space ownership in the context of carbon storage and produced water.

Water Rights

Tennessee bases allocation of water in watercourses and lakes on the doctrine of riparian rights.⁵⁵ The lack of recent case law leads to uncertainty as to the particulars of riparian rights in the state. A riparian owner possesses the right to use the water in the watercourse, not the water itself.⁵⁶

If a person owns real property, corresponding groundwater rights are also acquired.⁵⁷ Only one case addresses the right to use percolating groundwater in Tennessee.⁵⁸ Although the Court of Appeals stated that the

³⁶ *McBurney v. Glenmary Coal & Coke Co.*, 121 Tenn. 275, 118 S.W. 694, 699 (1909), *overruled in part by* Northcut, 188 S.W. at 220.

³⁷ *Id.*

³⁸ *McBurney*, 118 S.W. at 699.

³⁹ *See Smith v. Glen Alden Coal Co.*, 347 Pa. 290, 296, 32 A.2d 227 (1943).

⁴⁰ *See generally Townes v. Cox*, 162 Tenn. 624, 39 S.W.2d 749, 752 (1931).

⁴¹ *Id.*

⁴² *Townes*, 39 S.W.2d at 752.

⁴³ *See* TENN. CODE ANN. § 60-1-601 (West 2020) (providing that §§ 60-1-601 to -608 "shall be known and may be cited as the 'Oil and Gas Surface Owners Compensation Act of 1984'").

⁴⁴ TENN. CODE ANN. § 60-1-602 (West 2020).

⁴⁵ TENN. CODE ANN. § 60-1-604 (West 2020).

⁴⁶ TENN. CODE ANN. § 60-1-607 (West 2020).

⁴⁷ TENN. CODE ANN. § 60-1-608 (West 2020).

⁴⁸ *See Kidd v. Jarvis Drilling, Inc.*, No. M200400973COAR3CV, 2006 WL 344755 *3 (Tenn. Ct. App. Feb. 14, 2006).

⁴⁹ *See generally* TENN. COMP. R. & REGS. 1040-04-08-.01; TENN. COMP. R. & REGS. 1040-4-8-.01(1)-(2).

⁵⁰ TENN. COMP. R. & REGS. 0400-54-08-.01.

⁵¹ *Id.*

⁵² *See* TENN. CODE ANN. § 66-7-103 (West 2020).

⁵³ *Id.*

⁵⁴ *Id.*

⁵⁵ *Webster v. Harris*, 111 Tenn. 668, 69 S.W. 782, 789-90 (1902), *overruled on other grounds by* State ex rel. Cates v. West Tenn. Land Co., 127 Tenn. 575, 158 S.W. 746 (1913); *Webster v. Fleming*, 21 Tenn. (2 Hum.) 518 (1841).

⁵⁶ *Keltner v. Open Lake Sporting Club*, 2003 Tenn. App. LEXIS 128 (2003).

⁵⁷ *See generally Nashville, C. & St. L. Ry. v. Rickert*, 19 Tenn. App. 446, 89 S.W.2d 889 (1935), cert. denied (Tenn. Sup. Ct. 1936).

⁵⁸ *Id.*

reasonable use, or “American Rule,” applied in the state, the court appeared to use the correlative rights rule. The correlative rights rule builds upon the reasonable use rule and differs by not prohibiting off-site uses and by imposing a proportionality rule. Therefore, under correlative rights, a landowner must limit the use of groundwater so as to not interfere with the use of the water by others overlying the aquifer. Only four other states (California, Hawaii, Iowa, and Oklahoma) use the correlative rights doctrine. Nebraska uses a combination of the reasonable use rule and the correlative rights rule.

Lithium Ownership and Extraction

No statutes or cases specifically enumerate rules for lithium extraction. Tennessee’s mining regulatory scheme is almost entirely focused on coal.⁵⁹

Classification of CO₂: Pollutant

Tennessee’s statutory and regulatory scheme does not contemplate CO₂ as a commodity within the context of mining. The only reference to CO₂ as a commodity refers to food processing and the protections afforded by Tennessee consumer protection laws.⁶⁰ Tennessee’s oil and gas severance taxes apply only to fluid hydrocarbon gasses, and thus would not apply to CO₂.⁶¹ In other contexts, however, state law classifies CO₂ as a pollutant and emission that needs to be regulated.⁶²

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The Tennessee Board of Water Quality, Oil and Gas (“Board”) holds the duty to ensure waste does not occur, and “to make such inquiries as necessary to determine whether waste exists or is imminent.”⁶³ The Board is required to provide a public hearing before any rule or order is made,⁶⁴ and the Tennessee Rules and Regulations list notice and comment requirements for

injection wells.⁶⁵ The Board may force a “volumetric or surface poolwide unit, provided that the pool producers owning more than 50% of the pool acreage request such unitization of the pool” after a 60-day notice period to owners, and in the absence of a voluntary unitization agreement.⁶⁶

In the context of oil and gas, subsurface trespass appears nowhere in the Tennessee statutes or case law. Tennessee is an ownership-in-place state,⁶⁷ and seemingly no case law exists where a subsurface trespass cause of action, nor a defense like the rule of capture, was applied in the context of oil and gas. The most similar cause of action relates to claims of trespass in mining operations. An inadvertent or innocent trespass onto an adjacent tract of land for the removal of coal allows the plaintiff to recover the value of the coal at the mouth of the mine, minus the extraction and production costs.⁶⁸ The trespasser is responsible for any damage to the surface estate.⁶⁹ Conversely, if the Court finds the trespass was intentional, the trespasser cannot subtract the costs of production from the market value of the coal.⁷⁰

Tennessee recognizes correlative rights and mandates the existence of a pooling agreement between all owners over a pool⁷¹ and the operator wishing to extract minerals.⁷² Without this agreement, the operator can be

“The Tennessee Board of Water Quality, Oil and Gas (“Board”) holds the duty to ensure waste does not occur, and “to make such inquiries as necessary to determine whether waste exists or is imminent.”

⁵⁹ See generally TENN. CODE ANN. § 59-8-111 (West 2020); TENN. CODE ANN. § 59-8-106 (West 2020); TENN. CODE ANN. § 59-8-127 (West 2020); TENN. CODE ANN. § 59-8-203 (West 2020).

⁶⁰ See generally *Messer Griesheim Indus. v. Cryotech of Kingsport, Inc.*, 45 S.W.3d 588 (Tenn. Ct. App. 2001); *Messer Griesheim Industries, Inc. v. Cryotech of Kingsport, Inc.*, 2003, 131 S.W.3d 457.

⁶¹ Tenn. Code Ann. § 60-1-101 (West 2020).

⁶² See generally TENN. CODE ANN. § 68-201-121 (West 2016); TENN. COMP. R. & REGS. 1200-03-16-.04 (1981) (regulating solid waste incinerators); TENN. COMP. R. & REGS. 1200-03-16-.09 (1988) (regulating petroleum refineries).

⁶³ See TENN. CODE ANN. § 60-1-202(a)(2) (West 2020); but see 2018 Tenn. Pub. Acts, ch. 839, §§ 14-18, 47 (providing for transfer of authority to the Tennessee Board of Energy & Natural Resources upon deposit of federal funds in the Coal Mining Protection Fund).

⁶⁴ TENN. CODE ANN. § 60-1-204(b) (West 2020).

⁶⁵ See TENN. COMP. R. & REGS. 0400-45-06-.08(7) (2020).

⁶⁶ TENN. CODE ANN. § 60-1-202(a)(4)(N) (West 2020).

⁶⁷ Danielle Quinn, *A Fracking Fragile Issue: Courts Continue to Tiptoe Around Subsurface Trespass Claims*, 27 VILL. ENVTL. L.J. 1, 13 (2016).

⁶⁸ *Coal Creek Min. & Mfg. Co. v. Mose*, 83 Tenn. 300, 310 (Tenn. 1885).

⁶⁹ *Id.* at 309.

⁷⁰ *Dougherty v. Chesnutt*, 86 Tenn. 1 (Tenn. 1887).

⁷¹ Pool is defined as “an underground reservoir containing a common accumulation of crude petroleum oil or natural gas or both.” TENN. CODE ANN. § 60-1-101(1) (West 2020).

⁷² TENN. CODE ANN. § 60-1-202(4)(M)-(O) (West 2020).

prevented from proceeding.⁷³ The existence of correlative rights and mandated pooling agreements possibly allows Tennessee courts to avoid addressing whether incidental fracturing and drainage of natural gas from another's property is trespass. The person most likely to bring suit, a neighbor located over the same pool, has already agreed to this incidental fracturing and drainage, for which they are likely compensated.

Tennessee classifies EOR injection wells as Class II.⁷⁴ Class II wells are subject to the permit requirements contained within the same regulatory chapter for all injection wells,⁷⁵ in addition to permitting requirements specific to Class II wells.⁷⁶

The Commissioner of Environment and Conservation may require, "on a selective well-by-well basis, an owner or operator of an injection well to establish and maintain records, make reports, conduct monitoring, and provide other information as is deemed necessary to determine whether the owner or operator has acted or is acting in compliance with the Tennessee Water Quality Act or its implementing regulations."⁷⁷ To exempt an aquifer from certain permitting requirements necessary for protecting "underground source of drinking water," the Commissioner must find that the aquifer was never a source of drinking water and cannot now or in the future "serve as a source of drinking water."⁷⁸ No mention of induced seismicity or quantification of incidental storage of CO₂ was found in Tennessee laws or regulations.

A permittee must monitor "injection fluids, injection operations, and local ground water supplies" and maintain records of monitoring.⁷⁹ Each permit must have a topographic map detailing all potential sources of drinking water within a quarter-mile of the facility property.⁸⁰ Upon request, the Commissioner may inspect the records of the operator to ensure compliance with the UIC permit.⁸¹ An application for a permit must include a plan to prevent pollution to surface waters with sufficient detail to allow an inspector to locate the site of the facilities and to estimate environmental impact.⁸²

Pipeline Regulation

Through certification by OPS, Tennessee inspects and enforces the pipeline safety regulations for intrastate gas and hazardous liquid pipeline operators in the state.⁸³ The Gas Pipeline Safety Division of the Tennessee Regulatory Authority performs this work.⁸⁴ Title 65, Chapter 28 of the Tennessee Code, and the regulations promulgated thereunder, govern pipeline safety in the state.⁸⁵ By letter dated December 31, 2019, OPS notified the state that its enforcement of Tennessee's excavation damage prevention law was "adequate."⁸⁶

In Tennessee, a pipeline corporation has the right to appropriate as an easement or right-of-way lands which may be necessary for its pipelines or the construction and operation of underground storage reservoirs for natural gas, when in pursuance of the general laws authorizing condemnation of private property for works of internal improvement.⁸⁷ Specifically, the Tennessee office of the Attorney General opined in 2009 that "a pipeline corporation has the right to condemn an easement for pipelines that will be used for the transportation and distribution of carbon dioxide."⁸⁸ Pipeline corporations are classified as common carriers.⁸⁹

State Environmental Laws

Tennessee obtained primacy for the UIC Class I-V programs under Section 1422 of the SDWA on July 6, 2015.⁹⁰ Class I-V wells are regulated by the Tennessee Department of Environment and Conservation.⁹¹ U.S. EPA Region 4 directly implements the regulations for Class VI wells.⁹²

Under Tennessee Regulation 0400-12-01.02 regarding identification and listing of hazardous waste, carbon dioxide streams captured and transported for the purpose of injection into an underground well subject

⁸³ U.S. DEP'T OF TRANSP., PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, Regulatory Fact Sheet: Ohio, https://primis.phmsa.dot.gov/comm/FactSheets/States/OH_State_PL_Safety_Regulatory_Fact_Sheet.htm.

⁸⁴ *Id.*

⁸⁵ TENN. CODE ANN. § 65-28-105 (West).

⁸⁶ Letter from Massoud Tahamtani, Deputy Associate Director, Policy and Programs, Office of Pipeline Safety, to Robin L. Morrison, Chairman, Tenn. Public Utility Commission (Dec. 31, 2019), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-05/Signed-TN-Notice-of-Adequacy-Letter-for-2019-PHP-20-0085.pdf>.

⁸⁷ TENN. CODE ANN. § 65-28-101 (West 2020).

⁸⁸ Tenn. Op. Att'y Gen. No. 09-165 (Oct. 15, 2009).

⁸⁹ *See, e.g.*, TENN. CODE ANN. § 65-28-102 (West 2020).

⁹⁰ State of Tennessee Underground Injection Control (UIC) Program; Primacy Approval, 80 Fed. Reg. 65 (Apr. 6, 2015).

⁹¹ U.S. ENVTL PROT. AGENCY, Underground Injection Control in EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, and TN), <https://www.epa.gov/uic/underground-injection-control-epa-region-4-al-fl-ga-ky-ms-nc-sc-and-tn> (last visited Sept. 15, 2020).

⁹² *Id.*

⁷³ *Id.*

⁷⁴ *See* TENN. COMP. R. & REGS. 0400-45-06-.06 (2020).

⁷⁵ *See* TENN. COMP. R. & REGS. 0400-45-06-.08(13) (2020).

⁷⁶ *See* TENN. COMP. R. & REGS. 0400-45-06-.11(2020).

⁷⁷ *See* TENN. COMP. R. & REGS. 0400-45-06-.09(11) (2020).

⁷⁸ *See* TENN. COMP. R. & REGS. 0400-45-06-.04(7) (2020).

⁷⁹ *See* TENN. COMP. R. & REGS. 0400-45-06-.08(13)(j)-(l) (2020).

⁸⁰ *See* TENN. COMP. R. & REGS. 0400-45-06-.08(1)(g) (2020).

⁸¹ *See* TENN. COMP. R. & REGS. 0400-45-06-.08(13)(h) (2020).

⁸² *See* TENN. CODE ANN. § 60-1-103(a)(4) (West 2013).

to Class VI UIC regulations are not a hazardous waste if certain conditions are met.⁹³ All transportation of carbon dioxide streams must comply with the USDOT requirements, including the pipeline safety laws and regulations of USDOT and a state authority pursuant to certification under 49 U.S.C. § 60105.⁹⁴ Injection of a CO₂ stream must comply with requirements for Class VI UIC wells, including those in 40 C.F.R. Parts 144 and 146 and Tennessee Rules and Regulations Chapter 0400-45-06.⁹⁵ Additionally, no hazardous wastes shall be mixed with the CO₂ stream.⁹⁶ If any generator of a CO₂ stream or any Class VI UIC well owner or operator claims that the stream is excluded under these regulations, an authorized representative must sign a certification statement.⁹⁷

Industrial Siting Requirements

Our research did not reveal additional industrial siting requirements related to CO₂-EOR or Geologic Storage.

Local Regulation

Title 60 of the Tennessee Code governs oil and gas within the state, with chapters regarding the production of oil and gas, the inspection of volatile oils, and the production of fuel alcohol.⁹⁸ However, the Tennessee Code does not specifically refer to or provide guidelines for local regulations, nor does it discuss local preemption. Additionally, no cases could be located in Tennessee that discuss bans on natural gas extraction, permitting requirements, performance standards, setbacks, or regulating the disposal or storage of wastewater and other by-products of fracking.

The regulations are similarly broad.⁹⁹ The only regulation that may preempt local government regulation involves well spacing.¹⁰⁰ Those well spacing requirements may preempt local zoning setbacks, although no clear authority exists. However, in 2012, the Court of Appeals of Tennessee found that a natural gas system was potentially liable for franchise fees under an ordinance enacted by two towns in Tennessee because they are “operating taxes” for the privilege of doing business.¹⁰¹ Additionally, Title 13 of the Tennessee Code governs public planning,

with a chapter on zoning that grants zoning powers to municipalities and provides specific requirements for exercising the power.¹⁰²

Tribal Land

There are no state or federally recognized tribes in Tennessee.

Eminent Domain:

Eminent domain provides the government and those entities to whom the government delegates such authority, to condemn and take, either in whole or in part, private property of another, so long as the property is taken for legitimate public use.¹⁰³ “Public use” permits a public or private utility, a governmental or quasi-governmental utility, a common carrier, or any entity authorized under Title 65 to condemn land necessary.¹⁰⁴ Title 65 addresses public utilities and carriers and is discussed below.

Tenn. Code Ann. Section 29-16-101 provides that “any person or corporation authorized by law to construct any railroad, turnpike, canal, toll bridge, road, causeway, or other work of internal improvement to which the like privilege is conceded” may take the property of individuals under the terms prescribed in this section.¹⁰⁵ The Tennessee Supreme Court has held that a pipeline corporation’s installation of a pipeline is a work of internal improvement.¹⁰⁶

Tennessee adopted the Energy Acquisition Corporations Act in 2015.¹⁰⁷ The legislative intent reflects the importance of dependable and economic sources of energy to the citizens of Tennessee and recognizes that the markets for natural gas and electrical power have undergone major changes.¹⁰⁸ This chapter provides public corporations within the municipalities¹⁰⁹ with inherent powers regarding natural gas.¹¹⁰ Energy acquisition corporations may condemn property for, *inter alia*, pipelines, “underground and above ground storage reservoirs for natural gas and natural gas substitutes,” and pumping and terminal stations.¹¹¹

¹⁰² See T.C.A. § 13-7-201 et seq.

¹⁰³ See TENN. CODE ANN. § 29-17-102 (West 2020). Must be in accordance with the fifth and fourteenth amendments of the United States Constitution, the Constitution of Tennessee, Article One, Section 21, and Chapter 863 of the Public Acts of 2006.

¹⁰⁴ TENN. CODE ANN. § 29-17-102 (2) (West 2020).

¹⁰⁵ TENN. CODE ANN. § 29-16-101 (West 2020) (emphasis added).

¹⁰⁶ See *generally* Shinkle v. Nashville Improvement Co, 172 Tenn. 555, 113 W.2d 404 (1938).

¹⁰⁷ See TENN. CODE ANN. § 7-39-101 et seq. (West 2020).

¹⁰⁸ TENN. CODE ANN. § 7-39-101(b) (West 2020).

¹⁰⁹ “Energy Acquisition Corporations” appear to refer to these “public corporations within the municipalities.” See TENN. CODE ANN. § 7-39-102 (West 2020).

¹¹⁰ See TENN. CODE ANN. § 7-39-101(b)(1)-(5) (West 2020).

¹¹¹ TENN. CODE ANN. § 7-39-303(a) (West 2020).

⁹³ TENN. COMP. R. & REGS. 0400-12-01-.02 (2020).

⁹⁴ *Id.*

⁹⁵ *Id.*

⁹⁶ *Id.*

⁹⁷ TENN. COMP. R. & REGS. 0400-12-01-.02.

⁹⁸ See TENN. CODE ANN. § 60-1 (West 2020); TENN. CODE ANN. § 60-3 (West 2020); TENN. CODE ANN. § 60-4 (West 2020).

⁹⁹ See TENN. COMP. R. & REGS. 0400-52-01 to 12 (West 2020).

¹⁰⁰ See TENN. COMP. R. & REGS. 0400-52-04.01 (West 2020) (providing that local regulations regarding well spacing must conform to state rules).

¹⁰¹ See *Town of Middleton v. City of Bolivar*, No. W2011-01592-COA-R3CV, 2012 WL 2865960, at *1 (Tenn. Ct. App. 2012).

A pipeline corporation has the right to appropriate, either as an easement or right-of-way, the lands necessary for its pipelines.¹¹² A pipeline corporation also has the right to appropriate lands for the development, construction, and operation of underground storage reservoirs for natural gas.¹¹³ A corporation that is authorized to construct, own, and operate a gas or electric plant, or authorized to store, transport, or distribute natural or artificial gas or oil, for sale to the public or utility corporations for resale, or authorized to construct and maintain pipelines, is empowered to condemn such land as necessary.¹¹⁴ If the owner and the corporation cannot agree upon the amount of compensation to be paid, the taking shall proceed in the manner provided by Title 29, Chapter 16, of the Tennessee Code.¹¹⁵

Municipal corporations are empowered to take and condemn lands and property for the purposes of constructing, laying, repairing or extending sewers, water pipes, natural gas mains and pipes, and for the repairing and maintenances of each.¹¹⁶ A corporation that is authorized to construct, own, and operate gas or electric plants, or authorized to store, transport, or distribute natural or artificial gas or oil, for sale to the public or to utility corporations for resale, or authorized to construct and maintain pipelines, is empowered to acquire the right to use, employ, and divert such water flowing in and running into any stream or watercourse as may be necessary.¹¹⁷

Interestingly, Tennessee has a specific provision for condemnation of water for railroad corporations.¹¹⁸ This provision enables railroad corporations to condemn the use of water from any running stream, and also a way along which to lay pipelines or lines to transport water to its reservoir tanks, whenever water is needed for railroad purposes.¹¹⁹ This section only applies to erecting and maintaining tanks and reservoirs for railroad purposes only, and it does not apply to springs or private ponds.¹²⁰ Tennessee seems to be silent on the condemnation of water for pipeline or CO₂ purposes.

A pipeline corporation has the right to appropriate lands for underground storage reservoirs for natural gas.¹²¹ Additionally, the Energy Acquisition Corporations Act enables public corporations and municipalities to acquire

“gas in reservoirs or in storage.”¹²² Section 7-39-303 states that a corporation has the right to acquire lands, property, property rights, and easements for the development, construction, and operation of underground reservoirs for natural gas and natural gas substitutes.¹²³

Regarding CO₂, the Attorney General of Tennessee opined that a pipeline corporation has the right to condemn an easement for pipelines that will be used for the transportation and distribution of carbon dioxide.¹²⁴ Though not binding authority in Tennessee, government officials rely upon Attorney General Opinions for guidance. The Supreme Court of Tennessee ruled that these opinions are entitled to considerable deference, including opinions on issues of statutory construction, which includes this Attorney General Opinion.¹²⁵

Geologic CO₂ Storage Regulation and Incremental Storage:

Tennessee does not have a CO₂ sequestration scheme. However, the Attorney General issued an opinion that pipeline corporations have the right to condemn land used for the transportation and distribution of carbon dioxide.¹²⁶ To our knowledge, no projects have yet been developed.

Any district created under the authority of Chapter 82, Utility District Law of 1937, is empowered to conduct, operate, and maintain a system or systems for natural gas, natural gas storage, and related facilities.¹²⁷ In doing so, the district holds the authority to acquire, construct, reconstruct, improve, better, extend, consolidate, maintain, and operate such system or systems within or without the district.¹²⁸ Additionally, districts have the power to purchase from, and furnish, deliver, and sell any of the services authorized within the Chapter to any municipality, the state, any public institution and the public.¹²⁹

¹¹² TENN. CODE. ANN. § 65-28-101 (West 2020).

¹¹³ *Id.*

¹¹⁴ See TENN. CODE. ANN. § 65-22-101 (West 2020).

¹¹⁵ See generally TENN. CODE. ANN. § 29-16-101 *et seq.* (West 2020)

¹¹⁶ TENN. CODE. ANN. § 29-17-301 (West 2020).

¹¹⁷ TENN. CODE. ANN. § 65-22-101 (West 2020).

¹¹⁸ See TENN. CODE. ANN. § 65-6-123 (West 2020).

¹¹⁹ *Id.*

¹²⁰ *Id.*

¹²¹ TENN. CODE. ANN. § 65-28-101 (West 2020).

¹²² TENN. CODE. ANN. § 7-39-101(b)(1) (West 2020).

¹²³ TENN. CODE. ANN. § 7-39-303(a)(2) (West 2020).

¹²⁴ *Condemnation of Easement by Private Corporation for Pipeline*, Op. Att’y Gen. No. 09-165 (2009), 2009 WL 3479583.

¹²⁵ See *State v. Black*, 897 S.W.2d 680, 683 (Tenn. 1995).

¹²⁶ *Condemnation of Easement by Private Corporation for Pipeline*, Op. Att’y Gen. No. 09-165 (2009), 2009 WL 3479583.

¹²⁷ TENN. CODE ANN. § 7-82-302 (West 2020).

¹²⁸ *Id.*

¹²⁹ *Id.*

TEXAS

Executive Summary

Texas is historically one of the largest CO₂-EOR producing states in the U.S. A large, integrated pipeline network, along with CO₂ storage regulation, has primed Texas to also be a leader in CO₂ sequestration. However, judicial action regarding pore space may lead to future conflicts between mineral developers and CO₂ injectors, while the current rules and policy of the Texas Railroad Commission regarding pooling, unitization, and allocation wells could bring surface owners, mineral developers, and CO₂ injectors into both direct and indirect confrontation.

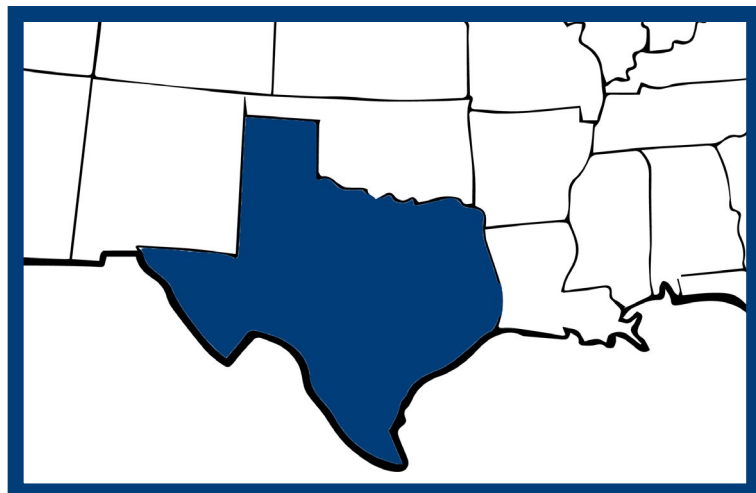
Background:

Texas encompasses 168,217,600 acres, which is comprised of federal, state, fee, and tribal land. Of this, only 2,231,198 acres (1.9%) is held under federal ownership. The majority of these federally owned lands lie in the eastern portion of the state; compared to other western states, this ownership is largely dispersed.

In Texas, the state's district courts serve as trial courts of general jurisdiction. The state also has 14 courts of appeals, which exercise intermediate appellate jurisdiction over civil cases appealed from the state's district courts. The state's court of last resort for all civil matters is the Supreme Court of Texas.

CO₂-EOR in Texas:

Texas could aptly be described as the cradle of CO₂-EOR. CO₂-EOR was first utilized in Scurry County, Texas in 1972 and continues to be extensively used throughout the Permian Basin, which underlies much of West Texas and extends into New Mexico, as well as other areas in the state.¹ For instance, Occidental's ongoing operations in the Permian Basin are responsible for the injection of approximately 2.6 Bcf of CO₂ per day, or 950 Bcf per year, making it a global leader in CO₂ injection and the largest injector within the basin.² Additionally, in 2016, a CCS project sponsored by the U.S. Department of



Energy and managed by the National Energy Technology Laboratory reported the transportation of its three millionth metric ton of CO₂ via pipeline from Port Arthur, Texas to the West Hastings Unit in southeast Texas for EOR purposes.³

An extensive pipeline network is currently in place for CO₂ transportation to and within the Permian Basin. The Cortez pipeline extends 502 miles from the McElmo Dome and Doe Canyon in southwestern Colorado;⁴ the Sheep Mountain Pipeline extends 408 miles from Sheep Mountain in central Colorado;⁵ and the Bravo pipeline extends 208 miles to the Bravo Dome of northeastern New Mexico.⁶ All three of these major pipelines converge at the Denver City CO₂ hub, for dispersal through a smaller pipeline network.⁷ In addition to these three major pipelines in the basin, the Canyon Reef Carrier CO₂ pipeline provides a 170-mile link between the Scurry Area Canyon Reef Operators Committee CO₂-EOR project, and the five gas processing plants in the Val Verde Basin of West Texas.⁸ Lastly, the Centerline and Central Basin CO₂ pipelines cover 113 and 143 miles, respectively, and are responsible for delivering natural CO₂ to the oil fields of West Texas and New Mexico from the Denver City Hub.⁹

¹ U.S. DEP'T OF ENERGY – OFFICE OF FOSSIL ENERGY, ENHANCED OIL RECOVERY, <https://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery> (last visited July 9, 2020); see also DENBURY, CURRENT TERTIARY OPERATIONS, <https://www.denbury.com/operations/gulf-coast-region/tertiary-operations/default.aspx> (last visited July 9, 2020).

² OXY, ENHANCED OIL RECOVERY, PERMIAN BASIN, <https://www.oxy.com/OurBusinesses/OilandGas/Technology/Enhanced-Oil-Recovery/Pages/default.aspx> (last visited July 12, 2020).

³ U.S. DEP'T OF ENERGY – OFFICE OF FOSSIL ENERGY, TEXAS CO₂ CAPTURE DEMONSTRATION PROJECT HITS THREE MILLION METRIC TON MILESTONE (2016), <https://www.energy.gov/fe/articles/texas-co2-capture-demonstration-project-hits-three-million-metric-ton-milestone> (last visited July 9, 2020).

⁴ U.S. DEP'T OF ENERGY – NAT. ENERGY TECH. LABORATORY, A REVIEW OF THE CO₂ PIPELINE INFRASTRUCTURE IN THE U.S., https://www.energy.gov/sites/prod/files/2015/04/f22/QR%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf (last visited July 12, 2020).

⁵ *Id.*

⁶ *Id.*

⁷ *Id.*

⁸ *Id.*

⁹ *Id.*

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Estate

Texas courts interpret deeds to ascertain the intent of the parties “as expressed in the instrument as a whole[.]”¹⁰ Thus, courts look to the four corners of the document to determine the parties’ intent.¹¹

Texas courts interpret general mineral conveyances dated before June 8, 1983 under the surface destruction rule, which vests ownership of all substances that come within 200 feet of the surface, and cannot be produced by “any reasonable method” without destruction or substantial damage to the surface, in the surface owner.¹² Courts use the ordinary and natural meaning rule for conveyances dated after June 8, 1983.¹³ Under this rule, courts give effect to the “general, rather than the specific, intent of the parties,”¹⁴ and construe a general grant or reservation to include all substances within the “ordinary and natural meaning” of the term “mineral.”¹⁵ Nevertheless, certain minerals, including limestone,¹⁶ caliche,¹⁷ surface shale,¹⁸ water,¹⁹ sand,²⁰ gravel,²¹ and “near surface” lignite and coal,²² have been found to be part of the surface estate as a matter of law.²³

Our research did not reveal statutes or case law addressing conflicts between competing mineral interests where concurrent or successive development is not possible.

Texas courts have not conclusively established whether or not a mineral estate owner may have a claim for subsurface trespass. In *Coastal Oil & Gas Corp. v.*

¹⁰ Luckel v. White, 819 S.W.2d 459, 462 (Tex. 1991).

¹¹ Altman v. Blake, 712 S.W.2d 117, 118 (Tex. 1986).

¹² Reed v. Wylie, 597 S.W.2d 743, 746-48 (Tex. 1980); see also Acker v. Guinn, 464 S.W.2d 348, 352 (Tex. 1971); see also Moser v. U.S. Steel Corp., 676 S.W.2d 99, 103 (Tex. 1984) (stating that the surface destruction rule will only be applied prospectively to conveyances

dated after June 8, 1983).

¹³ Moser, 676 S.W.2d at 103.

¹⁴ *Id.* at 102.

¹⁵ *Id.*

¹⁶ Heintz v. Allen, 217 S.W.2d 994 (Tex. 1949); Atwood v. Rodman, 355 S.W.2d 206 (Tex. Civ. App. 1962), writ ref’d NRE.

¹⁷ Atwood, 355 S.W.2d 206.

¹⁸ *Id.*

¹⁹ Fleming Foundation v. Texaco, 337 S.W.2d 846 (Tex. Civ. App. 1960), writ ref’d NRE.

²⁰ Psencik v. Wessels, 205 S.W.2d 658 (Tex. Civ. App. 1947), writ ref’d.

²¹ *Id.*

²² Reed v. Wylie, 597 S.W.2d 743 (Tex. 1980).

²³ Moser v. U.S. Steel Corp., 676 S.W.2d 99, 102 (Tex. 1984).

Garza Energy Trust, the Texas Supreme Court held that hydraulic fracturing does not, prima facie, give rise to a claim for trespass on the case by a reversionary interest owner.²⁴ Because the plaintiffs in *Garza* had leased their interest, they were required to demonstrate injury and damage to the remainder. The court reasoned that “actionable trespass requires injury,” and that the drainage of oil and gas from land caused by fracturing cannot constitute injury to the remainder under the rule of capture.²⁵ The court left open, however, the possibility for a claim of subsurface trespass where the mineral owner can show injury.²⁶ The *Coastal* court did not indicate whether it would reach a different result in a case between present interest owners.

Texas courts have also differentiated between transboundary migration of fluids for enhanced oil recovery and for wastewater disposal. In *Railroad Commission of Texas v. Manziel*, the court found that where a party had received a permit for enhanced recovery operations the migration of injected fluids did not result in a trespass.²⁷ This “inverse” or “negative” rule of capture, however, was not extended to protect injection of wastewater, even where the injector had a permit.²⁸ Texas courts have not ruled on whether the same recovery versus waste distinction would apply to injection of CO₂.

Split Estates

The mineral estate in Texas possesses an implied servitude for reasonable use of the surface estate.²⁹ Texas does not have a split estate statute or a surface protection act. Rather, under the accommodation doctrine adopted by the Texas Supreme Court in the landmark 1971 case *Getty Oil Co. v. Jones*,³⁰ the mineral developer must exercise its rights as the dominant tenement with due regard for the rights of the surface estate.³¹ Where a surface owner demonstrates that (1) the developer’s use of the surface prevents or “substantially” interferes with existing surface operations, (2) the surface owner does not have any reasonable alternative means available to continue such operations, and (3) the mineral developer has multiple viable production methods available, the mineral developer may be required to use one of the other

²⁴ *Coastal Oil & Gas Corp. v. Garza Energy Tr.*, 268 S.W.3d 1, 11-13 (Tex. 2008).

²⁵ *Id.*

²⁶ *Id.* 9-13.

²⁷ *RR Comm’n of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962)

²⁸ *Env’tl. Process. Sys., L.C. v. FPL Farming Ltd.*, 457 S.W.3d 414 (Tex. 2105).

²⁹ *Getty Oil Co. v. Jones*, 470 S.W.2d 618, 621 (Tex. 1971).

³⁰ *Id.* at 623.

³¹ *Id.* at 621-23.

available production methods.³² Where no alternatives exist, a reasonable method of production may be used despite any destruction to or interference with the surface estate.³³

The accommodation doctrine also extends to the mineral owners use of groundwater. Groundwater, unless expressly severed by either a grant or reservation, is part of the surface estate.³⁴ As with the surface itself, mineral developers have a right to reasonably use groundwater for development of the mineral estate unless the lease or severing instrument expressly states otherwise.³⁵ The groundwater estate may, however, like the mineral estate, be severed from the surface estate.³⁶ When this occurs, the Texas Supreme Court has extended the accommodation doctrine to disputes between the surface and groundwater estates.³⁷ For example, in *Coyote Lake Ranch, LLC v. City of Lubbock*, the court analogized the groundwater estate to the mineral estate and found that Lubbock had to accommodate Coyote Lake Ranch, the surface owner, in the development of the groundwater estate.³⁸

Pore Space Ownership

The Texas Supreme Court has held that reservoir, or pore space ownership rests in the surface owner as a matter of law.³⁹ For this reason, a surface owner may permit multiple uses of the pore space, including use of hydrocarbon bearing pore space, despite not owning the underlying minerals.⁴⁰ The mineral estate owner, or lessee, has no ownership interest in the pore space, but only the right to “explore, obtain, produce, and possess the minerals[.]”⁴¹ as well as the right to use the pore space subject to the accommodation doctrine.⁴² Thus, a developer may only bring a trespass claim against an additional use permitted by the surface owner if the other use “infringes” on the mineral estate.⁴³

³² *Merriman v. XTO Energy, Inc.*, 40 S.W.3d 244, 249 (Tex. 2013).

³³ *Tarrant Cty. Water Control & Imp. Dist. No. One v. Haupt, Inc.*, 854 S.W.2d 909, 911 (Tex. 1993).

³⁴ *Sun Oil Co. v. Whitaker*, 483 S.W.2d 808, 811 (Tex. 1972).

³⁵ *Id.*

³⁶ *See Coyote Lake Ranch, LLC v. City of Lubbock*, 498 S.W.3d 53, 63-64 (Tex. 2016).

³⁷ *Id.*

³⁸ *Id.* at 64-65

³⁹ *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39, 48 (Tex. 2017); *see also Humble Oil & Ref. Co. v. West*, 508 S.W.2d 812, 815 (Tex. 1974).

⁴⁰ *See Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39 (Tex. 2017).

⁴¹ *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39, 49 (Tex. 2017).

⁴² *See Coyote Lake Ranch, LLC v. City of Lubbock*, 498 S.W.3d 53, 60 (Tex. 2016); *see also supra* notes 29—33 and accompanying text.

⁴³ *Lightning Oil Co.*, 520 S.W.3d at 49.

“The Texas Supreme Court has held that reservoir, or pore, space ownership rests in the surface owner as a matter of law.”

Water Rights

Texas treats the allocation of groundwater and surface water within the state in vastly different ways. Surface water appropriations within the state are governed by the doctrine of prior appropriation.⁴⁴ State surface water⁴⁵ “may be appropriated, stored, or diverted[.]” after obtaining a permit from the Texas Commission on Environmental Quality (“TCEQ”), for a number of beneficial uses, most notably for the “mining and recovery of minerals[.]”⁴⁶ For purposes of priority, state law requires the TCEQ to rank “mining and recovery of minerals” third among beneficial uses, behind “domestic and municipal uses” and “agricultural uses and industrial uses.”⁴⁷ A TCEQ permit may be perfected through beneficial use for the purpose stated in the permit.⁴⁸ The right is “limited not only to the amount specifically appropriated but also to the amount which is being or can be beneficially used” for those purposes.⁴⁹ Water rights may be forfeited if the appropriation or use is “willfully abandoned during any three successive years[.]”⁵⁰

⁴⁴ TEX. WATER CODE ANN. § 11.027 (West 2020) (stating that “between appropriators, the first in time is the first in right”).

⁴⁵ TEX. WATER CODE ANN. § 11.021 (West 2020).

⁴⁶ *See* TEX. WATER CODE ANN. § 11.023 (West 2020) (enumerating uses for which water may be “appropriated, stored, or diverted”); TEX. WATER CODE ANN. § 11.121 (West 2020); *see also* TEX. WATER CODE ANN. § 11.142(c) (West 2020) (providing an exemption for “a person who is drilling and producing petroleum and conduction operations associated with drilling and producing petroleum[.]” and stating that water may be taken “for those purposes from the Gulf of Mexico and adjacent bays and arms of the Gulf of Mexico in an amount not to exceed one acre-foot during each 24-hour period”).

⁴⁷ TEX. WATER CODE ANN. § 11.024 (West 2020); (*see also* TEX. WATER CODE ANN. § 11.123 (West 2020)).

⁴⁸ TEX. WATER CODE ANN. § 11.026 (West 2020).

⁴⁹ TEX. WATER CODE ANN. § 11.025 (West 2020).

⁵⁰ TEX. WATER CODE ANN. § 11.030 (West 2020).

The state legislature has explicitly provided that the above surface water framework is not applicable to groundwater.⁵¹ Groundwater accounts for approximately 60% of the state's total water withdrawals.⁵² Generally, a landowner owns the groundwater underlying the land, and the rule of capture governs allocation of groundwater. The rule of capture provides that a landowner may take all the water that he or she is able to capture from below his or her land “without causing waste or malicious drainage of other property or negligently causing subsidence[.]”⁵³ The rule of capture may be modified however by administrative agencies. Texas has statutorily provided that groundwater conservation districts (“GCDs”) may be created for the purpose of “conserv[ing], preserv[ing], protect[ing], recharging, and prevent[ing] waste of groundwater[.]”⁵⁴ GCD rules modify the rule of capture by “limiting groundwater production based on tract size or the spacing of wells[.]”⁵⁵

Produced water use or disposal in Texas is subject to appropriation. A recently enacted Texas statute provides that produced water “is considered to be the property of the person who takes possession of it for the purpose of treating . . . for subsequent beneficial use.”⁵⁶ This rule may conflict with Texas’ rule of capture for groundwater, which vests ownership of groundwater with the surface owner. Appropriated produced water is freely transferable for disposal or beneficial use; ownership is transferred along with the physical transfer.⁵⁷ The statute insulates the transferor of produced water for use in connection with oil and gas drilling and production from liability for any consequences of the subsequent uses.⁵⁸ However, this indemnification does not extend to “damages for personal injury, death or property damage arising from exposure to” produced water.⁵⁹ The Railroad Commission of Texas (“RRC”) also has rulemaking powers necessary for governing the treatment and beneficial use of produced water.⁶⁰

Both surface water and ground water may be acquired by eminent domain. “All political subdivisions of the state and constitutional governmental agencies

exercising delegated legislative powers” have been authorized to exercise eminent domain powers to take surface water necessary for “domestic, municipal, and manufacturing uses[.]”⁶¹ GCDs also possess eminent domain powers for the purpose of condemning up to a fee simple interest “if that property interest is within the boundaries of the district and necessary for conservation purposes, including recharge and reuse.”⁶² This power does not extend to takings for the sole purpose of acquiring rights in surface water or groundwater, or for the purpose of “production, sale, or distribution of groundwater or surface water.”⁶³ Any use of this power by a GCD must be done so in accordance with Chapter 21 of the state’s Property Code, which governs eminent domain, except that a “district is not required to deposit a bond.”⁶⁴

Lithium Ownership and Extraction

Our research did not reveal any statutes or case law regarding lithium production or development. Texas courts have not classified lithium as part of the mineral estate as a matter of law. Applying the “ordinary and natural meaning” test articulated in *Moser v. U.S. Steel Corp*⁶⁵, we hypothesize that Texas courts may consider lithium a mineral though not necessarily part of “oil” or “gas.” To our knowledge, Texas courts have not considered ownership of dissolved lithium in geothermal brines.

One of the United States’ largest deposits of rare-earth elements (“REEs”), including lithium, is located in Hudspeth County, Texas, at Round Top Mountain.⁶⁶ Texas Mineral Resources, working with USA Rare Earth,⁶⁷ is currently exploring and developing these deposits,⁶⁸ and plans to use conventional open-pit mining techniques in REE extraction.⁶⁹ On June 11, 2020, Texas Mineral Resources announced that its pilot processing plant, located in Wheat Ridge, Colorado, was officially open.⁷⁰

⁶¹ TEX. WATER CODE ANN. § 11.033 (West 2020).

⁶² TEX. WATER CODE ANN. § 36.105(a) (West 2020).

⁶³ TEX. WATER CODE ANN. § 36.105(b) (West 2020).

⁶⁴ TEX. WATER CODE ANN. § 36.105(c) (West 2020); *see also* TEX. PROPERTY CODE ANN. § 21.0121 (2020).

⁶⁵ 676 S.W.2d at 103

⁶⁶ NS ENERGY, ROUND TOP RARE EARTH AND CRITICAL MINERAL PROJECT, <https://www.nsenergybusiness.com/projects/round-top-rare-earth-critical-minerals/#:~:text=The%20Round%20Top%20project%20is,biggest%20desert%20in%20North%20America>. (last visited July 9, 2020).

⁶⁷ *Id.*

⁶⁸ TMRCORP, RARE EARTHS – ROUND TOP, http://tmrcorp.com/projects/rare_earths/#:~:text=Currently%2C%20TMRC%20is%20focused%20on,Natural%20Gas%2C%20Rail%2C%20Water (last visited July 9, 2020).

⁶⁹ NS Energy, *supra* note 66.

⁷⁰ TMRCORP, USA RARE EARTH’S RARE EARTH & CRITICAL MINERALS PILOT PLANT DEVELOPMENT AND PROCESSING FACILITY OFFICIALLY OPENS, http://tmrcorp.com/news/press_releases/index.php?content_id=219 (last visited July 9, 2020).

⁵¹ TEX. WATER CODE ANN. § 35.003 (West 2020).

⁵² TEX. WATER DEV. BD., GROUNDWATER, <https://www.twdb.texas.gov/groundwater/index.asp> (last visited July 12, 2020).

⁵³ *See* Houston & T.C. Ry. Co. v. East, 81 S.W. 279 (Tex. 1904) (establishing the rule of capture’s applicability to groundwater); *see also* TEX. WATER CODE ANN. § 36.002 (West 2019).

⁵⁴ TEX. WATER CODE ANN. § 36.0015(b) (West 2019).

⁵⁵ TEX. WATER CODE ANN. § 36.101(a) (stating the above proposition and providing a list of considerations that a GCD must take into account in exercising its rulemaking powers).

⁵⁶ TEX. NAT. RES. CODE ANN. § 122.002(1) (West 2020).

⁵⁷ TEX. NAT. RES. CODE ANN. § 122.002(2) (West 2020).

⁵⁸ TEX. NAT. RES. CODE ANN. § 122.003(a) (West 2020).

⁵⁹ TEX. NAT. RES. CODE ANN. § 122.003(b) (West 2020).

⁶⁰ TEX. NAT. RES. CODE ANN. § 122.004 (West 2020).

Other lithium production is currently underway in the Smackover Formation, along the Mexia-Talco Fault Zone.⁷¹ However, researchers suggest that current extraction methods are not economically feasible and are looking into geothermal energy production.⁷²

Classification of CO₂: Commodity and Pollutant

Texas treats CO₂, particularly that which is sold for EOR uses, as a commodity. For purposes of the state's severance tax under the Tax Code, "gas" is defined as "natural gas, casinghead gas, or other gas taken from the earth or water, whether produced from a gas well or a well also producing oil, distillate or condensate or both, or other products."⁷³ This tax does not apply to gas that is injected or used to lift oil, "unless sold for that purpose."⁷⁴

Texas also regulates CO₂ as a pollutant. CO₂ may fall within the Texas Clean Air Act⁷⁵ definitions and regulations for "air contaminant[s]," "air pollution,"⁷⁶ and for "greenhouse gas emissions."⁷⁷ Any new major sources or major modification involving greenhouse gas emissions must comply with the PSD program's requirements.⁷⁸

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The RRC has jurisdiction over oil and gas wells, oil and gas operators, common carrier pipelines, and pipeline operators.⁷⁹ The RRC is primarily tasked with waste prevention⁸⁰ and protection of correlative rights.⁸¹

Oil and gas operators, including EOR operators, are required to comply with all RRC production rules including permitting,⁸² spacing,⁸³ and setback

requirements,⁸⁴ as well as proration orders.⁸⁵ The RRC also regulates all Class II injection wells,⁸⁶ including produced water, or saltwater, disposal wells.⁸⁷ All disposal well operators must supply the RRC with information regarding the potential for induced seismicity.⁸⁸ In addition, the RRC may "modif[y], suspend[], or terminate[]" an injection well permit if it "is likely to be or determined to be contributing to seismic activity[.]"⁸⁹

Texas recognizes the rule of capture, but this principle may be modified by pooling, unitization, or allocation wells.⁹⁰ The RRC is authorized by the Mineral Interest Pooling Act of 1965⁹¹ to order the pooling of all interests within a spacing or proration unit.⁹² The RRC may take such action only on the application of any oil and gas interest owner in a spacing unit, a working interest owner, or the non-royalty owner of an unleased tract.⁹³ Such an order applies to all interest owners within the spacing unit.⁹⁴ Neither the RRC nor any other state agency is authorized by law to order unitization of a common pool. Under the 1949 Voluntary Unitization Act,⁹⁵ however, separate owners of any interest in a pool or reservoir may voluntarily unitize for secondary recovery purposes and natural gas storage.⁹⁶ Such an agreement is binding only on those who sign it, and does not bind any separate interest owner who does not execute it.⁹⁷ Additionally, such an agreement becomes effective only if approved by the RRC after proper notice and hearing.⁹⁸

Texas does not have a traditional "forced pooling" statute for oil and gas development; however, in the absence of pooling agreements or orders, the RRC has, since 2010, permitted "allocation wells,"⁹⁹ or horizontal wells drilled without first obtaining voluntary pooling agreements. The RRC does not prescribe or approve the allocation method, though it requires supporting documentation indicating

⁷¹ Private communication with William A. Ambrose, Principal Investigator, State of Texas Advanced Oil and Gas Resource Recovery Program, Bureau of Economic Geology, University of Texas at Austin (July 10, 2020).

⁷² See Pamela Daitch, *Lithium Extraction from Oilfield Brine*, (on file with the author), <https://repositories.lib.utexas.edu/bitstream/handle/2152/65645/DAITCH-THESIS-2018.pdf?sequence=1&isAllowed=y>.

⁷³ TEX. TAX CODE ANN. § 201.001(4) (West 2020).

⁷⁴ TEX. TAX CODE ANN. § 201.053 (West 2020).

⁷⁵ TEX. HEALTH & SAFETY CODE ANN. § 382.001 (West 2020) (providing that Chapter 382 "may cited as the Texas Clean Air Act").

⁷⁶ TEX. HEALTH & SAFETY CODE ANN. § 382.003 (West 2020).

⁷⁷ TEX. HEALTH & SAFETY CODE ANN. § 382.05102(a) (West 2020).

⁷⁸ TEX. ADMIN. CODE. § 116.160(a) (2020).

⁷⁹ TEX. NAT. RES. CODE ANN. § 81.051 (West 2020).

⁸⁰ TEX. NAT. RES. CODE ANN. § 85.045 (West 2020); TEX. NAT. RES. CODE ANN. § 86.011 (West 2020).

⁸¹ TEX. NAT. RES. CODE ANN. § 85.053 – 055 (West 2020); TEX. NAT. RES. CODE ANN. § 86.081 – 083 (West 2020).

⁸² 16 TEX. ADMIN. CODE § 3.5 (2020).

⁸³ 16 TEX. ADMIN. CODE § 3.37 – 38 (2020).

⁸⁴ *Id.*

⁸⁵ TEX. NAT. RES. CODE ANN. § 85.046, .048, .054, .055 (West 2020).

⁸⁶ 40 C.F.R. § 147.2201 (2020).

⁸⁷ 16 TEX. ADMIN. CODE § 3.9 (2020).

⁸⁸ *Id.* at(3).

⁸⁹ 16 TEX. ADMIN. CODE § 3.46(d)(1)(F) (2020).

⁹⁰ See *Browning Oil Co., Inc. v. Luecke*, 38 S.W.3d 625, 632-35 (Tex. App. 2000).

⁹¹ Mineral Interest Pooling Act, TEX. NAT. RES. CODE ANN. § 102.001 – 012 (West 2019).

⁹² TEX. NAT. RES. CODE ANN. § 102.011 (West 2020).

⁹³ TEX. NAT. RES. CODE ANN. § 102.012 (West 2020).

⁹⁴ TEX. NAT. RES. CODE ANN. § 102.011 (West 2020).

⁹⁵ Voluntary Unitization Act, TEX. NAT. RES. CODE ANN. § 101.001 – 052 (West 2020).

⁹⁶ TEX. NAT. RES. CODE ANN. § 101.011 (West 2020).

⁹⁷ TEX. NAT. RES. CODE ANN. § 101.012 (West 2020).

⁹⁸ TEX. NAT. RES. CODE ANN. § 101.013 (West 2020).

⁹⁹ See Texas R.R. Comm'n Oil & Gas Docket No. 06-0262000 (permitting the first allocation well in 2010); see also Texas R.R. Comm'n Oil & Gas Docket No. 08-0305330 ¶ 13 ("It has been Commission practice to allow the drilling of allocation wells.").

the allocation to each tract.¹⁰⁰ In 2000, before the RRC began permitting allocation wells, in *Browning Oil Co. v. Luecke* the Texas appellate court in Austin was confronted with a horizontal well drilled in violation of anti-dilution provisions in the lease.¹⁰¹ The *Luecke* court reasoned that the rule of capture does not apply to horizontal wells in the same way that it does to vertical wells, and therefore the lessors were not entitled to royalties for oil and gas produced from all tracts of land through which the horizontal wellbore was drilled.¹⁰² Rather, the lessors were entitled only to royalties from production that could be “attributed to their tracts with reasonable probability.”¹⁰³ Because there are currently no statutes, regulations, or case law directly relating to the allocation of production for allocation wells, many operators have allocated production based on the “reasonable probability” standard expressed in *Browning*.¹⁰⁴

Texas offers a reduced severance tax rate to EOR operations approved and certified by the RRC.¹⁰⁵ CO₂-EOR projects that use anthropogenic CO₂ may qualify for an additional 50% rate reduction if the CO₂ used is captured in Texas, would otherwise be classified as an industrial emission, can be measured as captured, and sequestered as a result of the project.¹⁰⁶ The RRC must certify such a project before it is eligible for the tax benefit.¹⁰⁷

The RRC is also tasked with regulating natural gas storage by the Underground Natural Gas Storage and Conservation Act of 1977.¹⁰⁸ This Act defines a storage reservoir as “any subsurface sand, stratum, or formation used or to be used for the underground storage of natural gas[.]”¹⁰⁹ When approved by the RRC, a natural gas storage operation may exercise eminent domain authority to condemn a storage reservoir¹¹⁰ in which the operators possesses at least 2/3 of the working and royalty mineral interests.¹¹¹ All injected natural gas remains the personal property of the injector.¹¹²

Pipeline Regulation

Texas contains roughly 200,000 miles of gas pipelines, 130,000 of which are intrastate lines.¹¹³ The Permian Basin, located largely in Texas, contains over 2,600 miles of CO₂ pipelines, of which approximately 1,960 are intrastate lines.¹¹⁴ The RRC regulates all intrastate gas, oil and CO₂ pipelines, as well as production and gathering lines.¹¹⁵ The RRC requires all such pipeline operators to at least comply with federal safety standards, but may impose “more stringent standards in particular situations.”¹¹⁶ Interstate pipelines are federally regulated.¹¹⁷

State Environmental Laws

Texas has primacy over all injection wells, with the exception of Class VI UIC wells which are regulated by the EPA.¹¹⁸ The RRC has sole authority over Class II UIC wells,¹¹⁹ and shares responsibilities with the TCEQ on the regulation of Class III and V wells.¹²⁰ Additionally, the TCEQ has sole responsibility over the administration of Class I and IV wells.¹²¹ The Texas Legislature enacted the Injection Well Act¹²² for the purpose of furthering the

“Texas has primacy over all injection wells, with the exception of Class VI UIC wells which are regulated by the EPA.”

¹⁰⁰ LORENZO GARZA & JOE STASULLI, RAILROAD COMMISSION OF TEXAS, PSA WELLS, ALLOCATION WELLS AND STACKED LATERALS: PERMITTING AND COMPLETION (June 23, 2015), <https://www.rrc.state.tx.us/media/29117/psa-wells-allocation-wells-and-stacked-laterals.pdf>.

¹⁰¹ *Browning Oil Co., Inc. v. Luecke*, 38 S.W.3d 625 (Tex. App. 2000).

¹⁰² *Id.*, at 645-46.

¹⁰³ *Id.*, at 645-47.

¹⁰⁴ See Clifton A. Squibb, *The Age of Allocation: The End of Pooling as We Know It?*, TEX. TECH L.R. 937.

¹⁰⁵ 16 TEX. ADMIN. CODE § 3.50 (2020).

¹⁰⁶ § 3.50(k)(1).

¹⁰⁷ § 3.50(k)(3) and (4).

¹⁰⁸ Underground Natural Gas Storage and Conservation Act, TEX. NAT. RES. CODE ANN. § 91.171 – 184 (West 2020).

¹⁰⁹ TEX. NAT. RES. CODE ANN. § 91.173(5) (West 2020).

¹¹⁰ TEX. NAT. RES. CODE ANN. § 91.174 (West 2020).

¹¹¹ TEX. NAT. RES. CODE ANN. § 91.179 (West 2020).

¹¹² TEX. NAT. RES. CODE ANN. § 91.182 (West 2020).

¹¹³ 3 Texas Law of Oil and Gas 13.6 (2020).

¹¹⁴ NAT’L ENERGY TECH. LABORATORY: OFFICE OF FOSSIL ENERGY, A REVIEW OF THE CO₂ PIPELINE INFRASTRUCTURE IN THE U.S., U.S. DEP’T OF ENERGY, 3-7 (Apr. 21, 2015).

¹¹⁵ 16 TEX. ADMIN. CODE § 8.1 (2020).

¹¹⁶ *Id.*

¹¹⁷ See 15 U.S.C.A. § 717f (West 2020); 49 U.S.C.A. § 60502 (West 2020); 49 U.S.C.A. § 60101 to 60141 (West 2020); 49 U.S.C.A. § 15301 (West 2020).

¹¹⁸ U.S. EVTL PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC), UNDERGROUND INJECTION CONTROL IN EPA REGION 6 (AR, LA, NM, OK, AND TX), <https://www.epa.gov/uic/underground-injection-control-epa-region-6-ar-la-nm-ok-and-tx> (last visited July 9, 2020).

¹¹⁹ 40 CFR § 147.2201 (2020).

¹²⁰ *Id.*

¹²¹ *Id.*

¹²² TEX. WATER CODE ANN. § 27.001 (West 2020) (providing that Chapter 27 of the Water code “may be cited as the Injection Well Act”).

state's policy "to maintain the quality of fresh water in the state to the extent consistent with the public health and welfare and the operation of existing industries, taking into consideration the economic development of the state, to prevent underground injection that may pollute fresh water[.]"¹²³ This Act also requires that "all reasonable methods" be used in the implementation of this policy, including permitting.¹²⁴ Consistent with this act, the RRC requires a permit for Class II Injection wells before "[a]ny person . . . engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources[.]"¹²⁵ A permit will be issued only "when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources."¹²⁶

The RRC has provided a process by which an operator may apply to certify CO₂ injected for EOR purposes, in order to document its storage.¹²⁷ To obtain this certification, an operator must submit a "Monitoring, Sampling, and Testing Plan," which must provide for, *inter alia*, "periodic monitoring of the useable water strata overlying the productive reservoir to monitor for changes in the quality due to CO₂ injection[.]"¹²⁸

Within the RRC, the Groundwater Advisory Unit ("GAU") provides "Groundwater Protection Determinations" for underground injection and other underground activities.¹²⁹ In doing so, the GAU helps ensure that the RRC is in compliance with the requirements set forth in its own regulations and the Injection Well Act, particularly that which requires "a letter of determination from the [RRC]" prior to issuance of a permit.¹³⁰ The complexity of this regulatory framework signals the emphasis Texas places on the protection of the state's precious groundwater resources.

Industrial Siting Requirements

The Federal Energy Regulatory Commission regulates the siting of interstate gas pipelines.¹³¹ The RRC only regulates the siting of intrastate "sour gas" pipelines,

defined as gas with 100 ppm or more of hydrogen sulfide.¹³² Otherwise, gas pipeline siting is largely governed by gas or electric corporations.¹³³

Local Regulation

The Texas constitution allows cities with a population over 5,000 to adopt a home rule charter.¹³⁴ Nevertheless, the RRC has exclusive jurisdiction over all oil and gas operations in the state.¹³⁵ The Texas Natural Resources Code expressly preempts local regulation, except for municipal ordinances on "aboveground activity" including "traffic, lights, or noise," that do not "effectively prohibit an oil and gas operation[.]"¹³⁶

Tribal Lands

Texas encompasses three federally recognized Indian Tribes and two additional tribes that are recognized by the state.¹³⁷ The three federally recognized Tribes within the state include the Alabama-Coushatta Tribe of Texas, the Kickapoo Traditional Tribe of Texas, and the Ysleta Del Sur Pueblo.¹³⁸ The Tribes recognized by the state include the Lipan Apache Tribe and the Texas Band of Yaqui Indians.¹³⁹ For all federally recognized tribes within the state, the EPA maintains primacy over the implementation of the UIC program on said tribal lands¹⁴⁰ and the BIA regulates leases of tribally-owned oil and gas interests.¹⁴¹

The Ysleta del Sur Pueblo is the only Pueblo Tribe in Texas, and the Tribe is largely located in the Ysleta section of El Paso, 13 miles from downtown.¹⁴² It has 76 acres of Tribal land in the western tip of the state.¹⁴³

¹³² 16 TEX. ADMIN. CODE § 3.106 (2020).

¹³³ TEX. UTIL. CODE ANN. § 181.004 (West 2020).

¹³⁴ TEX. CONST. art. XI, § 5.

¹³⁵ TEX. NAT. RES. CODE ANN. § 81.0523 (West 2020).

¹³⁶ *Id.*; see also City of Denton Ordinances, 35.5.10.1(A)(3), https://www.cityofdenton.com/CoD/media/City-of-Denton/Government/Ord_2015-233__Gas_Well_Drilling_and_Production_-_current.pdf, (recognizing state preemption and stating that its ordinance is intended to regulate activity under the authority given in Tex. Nat. Res. Code Ann. § 81.0523).

¹³⁷ NAT'L CONFERENCE OF STATE LEGISLATURES, FEDERAL AND STATE RECOGNIZED TRIBES, <https://www.ncsl.org/research/state-tribal-institute/list-of-federal-and-state-recognized-tribes.aspx#tx> (last visited July 11, 2020).

¹³⁸ *Id.*

¹³⁹ *Id.*

¹⁴⁰ U.S. EVTL PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC), UNDERGROUND INJECTION CONTROL IN EPA REGION 6 (AR, LA, NM, OK, AND TX), <https://www.epa.gov/uic/underground-injection-control-epa-region-6-ar-la-nm-ok-and-tx> (last visited July 9, 2020).

¹⁴¹ 25 C.F.R. §§ 211.1 to 212.58 (2020).

¹⁴² *About Us*, YSELTA DEL SUR PUEBLO, <https://www.ysletadelsurpueblo.org/about-us> (last visited July 17, 2020).

¹⁴³ *Where in Texas are Indigenous Peoples?*, THE TEXAS POLITICS PROJECT, https://texaspolitics.utexas.edu/archive/html/cult/features/0500_02/indianreservation.html (last visited July 17, 2020).

¹²³ TEX. WATER CODE ANN. § 27.003 (West 2020).

¹²⁴ *Id.*

¹²⁵ TEX. ADMIN. CODE. § 3.46(a) (2020).

¹²⁶ *Id.*

¹²⁷ TEX. ADMIN. CODE. § 5.303 (2020).

¹²⁸ TEX. ADMIN. CODE. § 5.305(1)(G) (2020); see also TEX. ADMIN. CODE. § 5.308(a) (2020) (providing that compliance with this plan must be maintained to verify geologic storage).

¹²⁹ R.R. COMM'N OF TEX., OIL & GAS, APPLICATIONS AND PERMITS, GROUNDWATER ADVISORY UNIT (GAU), <https://www.rrc.texas.gov/oil-gas/applications-and-permits/groundwater-advisory-unit/> (last visited July 12, 2020).

¹³⁰ TEX. WATER CODE ANN. § 27.033 (West 2020).

¹³¹ 15 U.S.C.A. § 717f (West 2020).

The KTTT Reservation encompasses 125 acres located just south of Eagle Pass, Texas and is situated alongside the Rio Grande and the U.S.-Mexico border.¹⁴⁴ Lastly, the Alabama-Coushatta Tribe of Texas has the oldest and largest reservation in the state, with approximately 10,200 acres of land in the Big Thicket of Deep East Texas near Houston.¹⁴⁵

The Alabama-Coushatta Tribe of Texas has an extensive natural resource management program, which includes the Tribal Environmental Office (“TEO”) and the Tribal Oil and Gas Department (“TOGD”).¹⁴⁶ The TEO is responsible for the protection of the Tribe’s human health and natural resources, and fulfills these responsibilities with the help of EPA funding through the General Assistance Program and Section 106 of the federal Clean Water Act.¹⁴⁷ This funding is used to conduct activities, including “building capacity and infrastructure, including planning and development; administrative, technical, and legal communication; and environmental education of tribal members.”¹⁴⁸ The TOGD has the responsibility of negotiating mineral leases, conducting well site evaluations, monitoring gas production, negotiating rights-of-way, arranging land use permits for seismic operations or other operations requiring temporary occupation of Tribal lands, and corresponding with the relevant federal agencies, such as the BIA and the BLM.¹⁴⁹ In addition, the TOGD maintains a record of production data, including production, revenue, oil and gas well files, lease agreements, and “all data pertaining to the Tribal minerals.”¹⁵⁰

We were not able to locate specific rules pertaining to oil and gas development on the remaining reservations.

Eminent Domain:

Article 1, Section 17 of the state’s constitution provides that just compensation must be paid in the event that a person’s property is “taken, damaged, or destroyed for or applied to a public use[.]”¹⁵¹ The Supreme Court of Texas, in *KMS Retail Rowlett, LP v. City of Rowlett*, held that “whether a taking is for a constitutional public use is a question ultimately decided by the courts, but . . . a legislative declaration on public use is entitled to our deference.”¹⁵² Like North Dakota, the Texas Constitution also expressly excludes a taking “for transfer to a private entity for the primary purpose of economic development or enhancement of tax revenues” from the meaning of “public use” in this section.¹⁵³ The state’s Government Code reiterates this prohibition, and also states that no property may be taken for any private, non-public, use.¹⁵⁴ Chapter 21 of the state’s Property Code provides general procedural requirements for condemnation proceedings within the state.¹⁵⁵ Specific grants of eminent domain power can be found elsewhere in Vernon’s Texas Statutes.

“Like North Dakota, the Texas Constitution also expressly excludes a taking “for transfer to a private entity for the primary purpose of economic development or enhancement of tax revenues” from the meaning of “public use” in this section.”

The state’s Natural Resource Code authorizes the use of eminent domain powers for common carrier pipeline operators to “enter on and condemn the land, rights-of-way, easements, and property of any person or corporation necessary for the construction, maintenance, or operation of the common carrier pipeline.”¹⁵⁶ Pipelines sited using this power must comply with statutory disclosure¹⁵⁷ and

¹⁴⁴ KICKAPOO TRADITIONAL TRIBE OF TEXAS, <https://kickapootexas.org/> (last visited July 17, 2020).

¹⁴⁵ *Our History*, ALABAMA-COUSHATTA TRIBE OF TEXAS, <https://www.alabama-coushatta.com/about-us/our-history/> (last visited November 3, 2020).

¹⁴⁶ U.S. ENVTL PROT. AGENCY, ALABAMA-COUSHATTA TRIBE OF TEXAS COMMUNITY-SCALE AIR TOXICS AMBIENT MONITORING PROJECT PROPOSAL (2018), <https://www3.epa.gov/ttnamti1/files/2015csatam/AlabamaCoushattaTribeTexasProjectNarrative.pdf> (last visited July 29, 2020).

¹⁴⁷ *Id.*

¹⁴⁸ *Id.*

¹⁴⁹ *Id.*

¹⁵⁰ *Id.*

¹⁵¹ TEX. CONST. art. 1, § 17(a).

¹⁵² *KMS Retail Rowlett, LP v. City of Rowlett*, 593 S.W.3d 175, 182 (Tex. 2019); *see also* Hous. Auth. of City of Dallas v. Higginbotham, 143 S.W.2d 79, 83 (Tex. 1940).

¹⁵³ TEX. CONST. art. 1, § 17(b).

¹⁵⁴ TEX. GOV’T. CODE ANN. § 2206.001(b) (West 2020).

¹⁵⁵ *See generally* TEX. PROP. CODE ANN. § 21.001 *et seq.* (West 2020).

¹⁵⁶ TEX. NAT. RES. CODE ANN. § 111.019(b) (West 2020).

¹⁵⁷ TEX. NAT. RES. CODE ANN. § 111.019(c) (West 2020).

restoration obligations.¹⁵⁸ Pipeline companies engaged in transportation of carbon dioxide and feedstock for carbon gasification,¹⁵⁹ and which are “to or for the public for hire,” may qualify as common carriers after filing a declaration and tariff with the Texas RRC.¹⁶⁰ Pipelines “limited in their use to the wells, stations, plants, and refineries of the owner and that are not a part of the pipeline transportation system,” are explicitly excluded from attaining common carrier status.¹⁶¹ However, in *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline*, the Texas Supreme Court held that merely complying with RRC registration requirements did not give a pipeline common carrier status and accompanying eminent domain authority.¹⁶² The court concluded that for a pipeline to actually meet the requirements of a common carrier, “a reasonable probability must exist that the pipeline will at some point after construction serve the public by transporting gas for one or more customers who will either retain ownership of the gas or sell it to parties other than the carrier.”¹⁶³

Geologic CO₂ Storage Regulation and Incremental Storage:

The RRC is tasked with regulating geologic storage of anthropogenic CO₂ to the extent that Texas has jurisdiction over such injection and storage.¹⁶⁴ The RRC defines a storage reservoir as a “natural or artificially created subsurface sedimentary stratum, formation, aquifer, cavity, void, or coal seam.”¹⁶⁵

Before beginning injection and storage procedures, an operator must apply for and be granted a permit from the RRC.¹⁶⁶ An application must include a seismic history of the area, as well as a report on the potential for seismicity caused by CO₂ injection.¹⁶⁷ Operators are required to provide financial assurances to the RRC before injection may begin in the form of a bond or surety deposit.¹⁶⁸ The RRC will grant a permit only after finding that CO₂ injection and storage will not damage any mineral or water sources and that the geology of the storage reservoir makes induced seismicity unlikely.¹⁶⁹

¹⁵⁸ TEX. NAT. RES. CODE ANN. § 111.0193 (West 2020).

¹⁵⁹ See TEX. NAT. RES. CODE ANN. § 111.002(6) (West 2020); see also TEX. NAT. RES. CODE ANN. § 111.002(7) (West 2020).

¹⁶⁰ See TEX. NAT. RES. CODE ANN. § 111.002(6) (West 2020); see also TEX. NAT. RES. CODE ANN. § 111.002(7) (West 2020); see also TEX. NAT. RES. CODE ANN. § 111.013 (West 2020).

¹⁶¹ TEX. NAT. RES. CODE ANN. § 111.003(a) (West 2020).

¹⁶² *Id.*

¹⁶³ *Id.* at 202.

¹⁶⁴ 16 TEX. ADMIN. CODE § 5.101 (2020).

¹⁶⁵ 16 TEX. ADMIN. CODE § 5.102(27) (2020).

¹⁶⁶ 16 TEX. ADMIN. CODE § 5.202 (2020).

¹⁶⁷ 16 TEX. ADMIN. CODE § 5.203(c) (2020).

¹⁶⁸ 16 TEX. ADMIN. CODE § 5.205 (2020).

¹⁶⁹ 16 TEX. ADMIN. CODE § 5.206 (2020).

The RRC may suspend or cancel a storage permit if the sequestration “endangers” drinking water sources, if the injected fluids are “escap[ing] from the injection zone[.]” or if the operator is violating the terms of the permit.¹⁷⁰

The RRC does not specify whether injected CO₂ remains the property of the operator, or whether ownership may at some point devolve to the state. However, Texas courts may analogize CO₂ sequestration to natural gas storage and find that ownership of and liability for injected CO₂ rests in the operator.¹⁷¹



“Texas courts may analogize CO₂ sequestration to natural gas storage and find that ownership of and liability for injected CO₂ rests in the operator.”

¹⁷⁰ 16 TEX. ADMIN. CODE § 5.202(d) (2020).

¹⁷¹ See TEX. NAT. RES. CODE ANN. § 91.182 (West 2020).

WEST VIRGINIA

Executive Summary

West Virginia enacted a limited statutory regime on CO₂ sequestration in 2009.¹ Pilot tests for secondary oil recovery occurred in the state as early as the 1960s², but little recent activity in enhanced oil recovery has occurred in the state. The West Virginia Carbon Dioxide Sequestration Work Group, formed by the State Legislature, identified in a 2011 report a number of barriers to CO₂ sequestration in the state, including the cost of acquiring pore space from landowners through eminent domain.³ Lack of pipelines and potential leakage from orphan wells also present challenges.⁴ In addition, “West Virginia, by far, has the longest and most complex series of oil and gas conservation statutes of all of the 50 states.”⁵ Similarly, deeds conveying mineral interests are interpreted on a case-by-case basis, creating uncertainty for mineral and landowners. Eminent domain rules are fairly liberal but are limited by a so-called “anti-Kelo” provision that limits eminent domain for economic development purposes. Although CO₂ infrastructure could be construed as “economic development,” this interpretation is unlikely.

Background:

West Virginia includes federal, state, and fee land. The majority of the state is private land. Only 7% of land is federally owned and an even smaller 2.9% of land is owned by the state. There is no tribal land within West Virginia.

A distinctive feature of land in Appalachia, including West Virginia, is the concentration of private surface land ownership in a relatively small number of out-of-state companies: mostly timber, energy, and land-holding companies. Although not as concentrated as in the past, the latest estimates indicate the top 25 landowners hold 17.6% of the state’s approximately 13 million acres of private land. The top ten landowners own at least 50% of private land in six counties in the state.

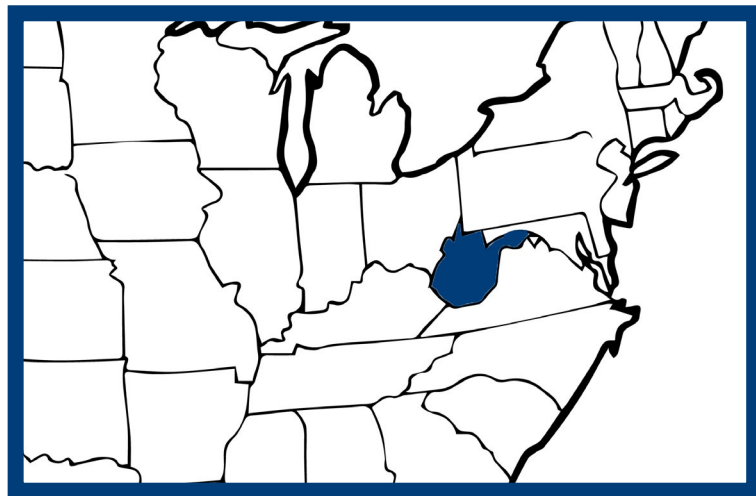
¹ W. VA. CODE ANN. § 22-11A-1 et seq. (West 2020).

² WEST VIRGINIA GEOLOGIC AND ECONOMICAL SURVEY (“WVGES”), ASSESSING SUITABILITY OF DEPLETED FIELDS FOR ENHANCED OIL RECOVERY IN WEST VIRGINIA, http://www.wvgs.wvnet.edu/www/presentations/2013/WVGES_AAPG2013_Poster_Panel_3.pdf (last visited Sept. 15, 2020).

³ THE WEST VIRGINIA CARBON DIOXIDE SEQUESTRATION WORKING GROUP, REPORT TO THE LEGISLATURE (July 2011), <https://dep.wv.gov/executive/Documents/WVCCS%20Working%20Group%20Final%20Report%20-%20June%2030,%202011.pdf>.

⁴ ASSESSING SUITABILITY OF DEPLETED FIELDS FOR ENHANCED OIL RECOVERY IN WEST VIRGINIA, *supra* note 2.

⁵ Bruce M. Kramer, *Compulsory Pooling and Unitization with an Emphasis on the Statutory and Common Law of the Eastern United States*, 27 ENERGY & MIN. L. FOUND. 223, 237 (2007).



Five of these counties are in the southern coalfields. In Wyoming County, located in the southern coalfields, the top ten landowners hold 75.8% of the private land. Much more of the mineral rights in the state are owned by out-of-state companies, but those data are difficult to gather, so the percentages are unknown.

Another feature of land ownership in Appalachia, Native American communities, and African American communities is the prevalence of “heirs’ property.” Heirs’ property is land that has been passed from generation to generation, often through intestacy. The land is highly fractionated with dozens, hundreds, or even thousands of owners. This fractionated ownership often forms a barrier to mineral development and might likewise present a barrier to the acquisition of pore space rights for incremental or geologic storage.

West Virginia has a common law legal system. Circuit Courts are the trial courts of general jurisdiction and there are 31 circuits. The Supreme Court of Appeals of West Virginia is the highest court in the state.

CO₂-EOR in West Virginia:

A handful of areas in West Virginia have been the subject of pilot tests, beginning as early as the 1960s, but there have been few successful CO₂ enhanced recovery projects, all of which are of relatively small scale.⁶ Notable CO₂-EOR projects include: (1) a pilot CO₂ flood in the Granny Creek field in the late 1970s, utilizing approximately 12,000 tons of CO₂; (2) operations in the Hilly Upland field, using 1,500 tons of CO₂; and (3) Walton-Rock Creek field operations, using approximately 24,000 tons of CO₂, beginning in 1976.⁷

⁶ RILEY, R., ET AL., EVALUATION OF CO₂-ENHANCED OIL RECOVERY AND SEQUESTRATION OPPORTUNITIES IN OIL AND GAS FIELDS IN THE MRCSP REGION, MRCSP PHASE II TOPICAL REPORT, DOE Cooperative Agreement No. DE-FC26-05NT42589 (Oct. 2005 – Oct. 2010).

⁷ ASSESSING SUITABILITY OF DEPLETED FIELDS FOR ENHANCED OIL RECOVERY IN WEST VIRGINIA, *supra* note 2.

The West Virginia Geologic and Economic survey identified a number of challenges to CO₂-EOR including lack of pipelines and potential leakage from orphan wells, which was a critical issue in the Walton-Rock Creek project.⁸ The historic oil fields in north-central West Virginia hold the potential for future secondary and tertiary recovery efforts despite the challenges.⁹

West Virginia has a limited statutory regime on CO₂.¹⁰ In addition to creating limited requirements for CO₂ storage, the statutory regime created the West Virginia Carbon Dioxide Sequestration Work Group. The Work Group created Feasibility, Geology and Technology, and Legal Subcommittees. The Group submitted an extensive report to the legislature in 2011, which included detailed reports from each subcommittee.¹¹

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

In West Virginia, deeds and leases are subject to the interpretation and construction that govern contracts generally.¹² When the language is plain and unambiguous, courts must apply, not construe, the contract.¹³ The controlling factor in interpretation is the intent of the parties.¹⁴

Grants and reservations of minerals have been interpreted on a case-by-case basis, given the specific facts of each case. Where there is a grant or reservation of minerals without other words of limitation or restriction, all minerals are granted or reserved.¹⁵ The term “mineral” includes petroleum and natural gas, unless the words of the conveyance or restriction indicate a contrary intent.¹⁶ Likewise, the reservation of “all minerals, coal, iron,

⁸ *Id.*

⁹ *Id.*

¹⁰ W. VA. CODE ANN. § 22-11A-1 et seq. (West 2020).

¹¹ THE WEST VIRGINIA CARBON DIOXIDE SEQUESTRATION WORKING GROUP, REPORT TO THE LEGISLATURE (July 2011), <https://dep.wv.gov/executive/Documents/WVCCS%20Working%20Group%20Final%20Report%20-%20June%2030,%202011.pdf>.

¹² See *Arnold v. Palmer*, 686 S.E.2d 725 (W. Va. 2009).

¹³ See *Faith United Methodist Church & Cemetery of Terra Alta v. Morgan*, 745 S.E.2d 461 (W. Va. 2013).

¹⁴ See *Murphy v. Van Voorhis*, 119 S.E. 297 (W. Va. 1923).

¹⁵ See *Waugh v. Thompson Land & Coal Co.*, 137 S.E. 895, 897-98 (W. Va. 1927).

¹⁶ *Sult v. A. Hochstetter Oil Co.*, 61 S.E. 307 (W. Va. 1908). See also *Prindle v. Baker*, 178 S.E. 513 (W. Va. 1935); *Burdette v. Bruen*, 191 S.E. 360 (W. Va. 1937); *Horse Creek Land & Mining Co. v. Midkiff*, 95 S.E. 26 (W. Va. 1918). But see *Buren v. Thaxton*, 28 S.E.2d 59 (W. Va. 1943) (a reservation of “all the coal and iron minerals” did not reserve oil and gas); *Murphy v. Van Voorhis*, 119 S.E. 297 (W. Va. 1923) (reservation retaining all oil privileges, including the right to “bore and mine on said land for minerals or [petroleum] oil...” did not reserve title to natural gas on the property).

etc.” includes oil and gas.¹⁷ However, although the term “mineral” generally includes sand and gravel, reservation of “oil, gas and other minerals” did not reserve sand and gravel.¹⁸ Where a deed references a separately described vein of coal, the conveyance does not include other veins of coal in the tract of land that were not known to the parties.¹⁹

Split Estates

The owner of a fee simple interest in land may sever the land into separate surface and mineral estates. The owner may convey ownership of a particular mineral underlying the tract, a seam of one mineral, or all minerals, retaining the surface of the tract.²⁰ The landowner may also convey the surface only while retaining the minerals. The separate estates created may later be conveyed or devised.²¹ The mineral estate is dominant to the surface estate. The language of a lease will dictate which estate is dominant between an oil and gas estate and a coal estate.²² The owner of the mineral estate has the implicit right to use the surface estate overlying the minerals in a reasonable manner to access the minerals.²³

A well-recognized rule in West Virginia recognizes that a landowner who has conveyed the underlying mineral estate retains the right to surface support “in its natural state” unless there is an express waiver to such support.²⁴ A lessee’s development of the mineral estate through off-site horizontal drilling falls within this implied right, even though horizontal drilling did not exist at the time of the lease.²⁵ In a recent case, West Virginia’s

¹⁷ See *Norman v. Lewis*, 130 S.E. 913, 914 (W. Va. 1925).

¹⁸ See *W. Va. Dept. of Highways v. Farmer*, 226 S.E.2d 717 (W. Va. 1976).

¹⁹ See *Armstrong v. Ross*, 55 S.E. 895 (W. Va. 1906).

²⁰ *EQT Production Company v. Crowder*, 241 W. Va. 738, 828 S.E.2d 800 (2019).

²¹ *Id.*

²² *Cabot Oil & Gas Corp. v. Pocahontas Land Corp.*, 180 W. Va. 200, 376 S.E. 2d 94, 97 (1988) (Oil and gas lease required lessee’s successor to move pipeline at lessee’s expense. Lease stated that oil and gas interests were subservient to coal estate and lease also provided that lessee would bear cost of pipeline relocation.).

²³ See *Squires v. Lafferty*, 95 W. Va. 307, 212 S.E. 90 (1924). See also *EQT Production Company v. Crowder*, 828 S.E.2d 800, 806 (W. Va. 2019); *Andrews v. Antero*, 828 S.E.2d 858 (W. Va. 2019).

²⁴ *Winnings v. Wilpen Coal Co.*, 59 S.E.2d 655, 658-59 (1950). See generally *Cogar v. Sommerville*, 379 S.E.2d 764 (W. Va. 1989); *Continental Coal Co. v. Connellsville By-Product Coal Co.*, 138 S.E. 737 (W. Va. 1927); *Cole v. Signal Knob Coal Co.*, 122 S.E. 268 (W. Va. 1924); *Goodykoontz v. White Star Mining Co.*, 119 S.E. 862 (W. Va. 1923); *Hall v. Harvey Coal & Coke Co.*, 108 S.E. 491 (W. Va. 1921); *Godfrey v. Weyanoke Coal & Coke Co.*, 97 S.E. 186 (W. Va. 1918); *Griffin v. Fairmont Coal Co.*, 53 S.E. 24 (W. Va. 1905); *McElroy Coal Co. v. Schoene*, 813 S.E.2d 128 (W. Va. 2018).

²⁵ *Andrews v. Antero*, 828 S.E.2d 858 (W. Va. 2019).

highest court held little or no difference existed between the impact of vertical drilling and horizontal drilling on the surface owner.²⁶ However, the mineral owner or lessee does not have the right, absent an agreement with the surface owners, to use the surface to benefit operations on other lands.²⁷ In 1994, the West Virginia Oil and Gas Production Damage Compensation Act statutorily declared that the right to explore and develop the mineral estate and the right to use the surface estate constitute equal rights, which coexist with one another.²⁸ This Act also places an obligation upon the mineral developer to compensate the surface estate owner for surface damages sustained during development,²⁹ and provides procedures by which the surface owner may notify the developer of a claim for such compensation.³⁰ In the absence of a written agreement, the developer has sixty days to make an offer of settlement or reject the surface owner's claim.³¹ However, a surface owner may still obtain compensation through arbitration or judicial proceedings commenced within eighty days of notification.³²

Pore Space Ownership

In *Tate v. United Fuel Gas*, the Supreme Court of Appeals of West Virginia interpreted a conveyance to conclude that pore space belonged to the surface owners.³³ The decision was premised on the specific and unique language of the mineral conveyance at issue in that case, thus the holding is narrow.³⁴ In *Tate*, the Court held that so long as no recoverable minerals existed in the subsurface stratum, the surface owner possessed the right to grant storage rights.³⁵ This too is fairly narrow, limiting the surface owner's subsurface rights only to storage and only within non-mineral bearing stratum, thus leaving ownership unclear across numerous other scenarios. No statutory provisions exist, and no other case law was found pertaining to pore space in West Virginia.

The West Virginia Carbon Dioxide Sequestration Working Group's Report to the Legislature in 2011 presumes that the pore space is owned by the surface owner.³⁶ The report cites payment of compensation

²⁶ *Id.*

²⁷ See EQT Production Company, 828 S.E.2d at 810.

²⁸ W. VA. CODE ANN. § 22-7-1(a)(1) (West 2020).

²⁹ W. VA. CODE ANN. § 22-7-3 (West 2020).

³⁰ W. VA. CODE ANN. § 22-7-5 (West 2020).

³¹ W. VA. CODE ANN. § 22-7-6 (West 2020).

³² W. VA. CODE ANN. § 22-7-7 (West 2020).

³³ See *Tate v. United Fuel Gas*, 71 S.E.2d 65 (W. Va. 1952).

³⁴ See generally *Tate v. United Fuel Gas*, 71 S.E.2d 65 (W. Va. 1952).

³⁵ *Id.*

³⁶ THE WEST VIRGINIA CARBON DIOXIDE SEQUESTRATION WORKING GROUP, REPORT TO THE LEGISLATURE (July 2011), [https://dep.wv.gov/executive/Documents/WVCCS%20Working%20Group%20Final%20](https://dep.wv.gov/executive/Documents/WVCCS%20Working%20Group%20Final%20Report%20-%20June%2030,%202011.pdf)

to the owners of the pore space as a major barrier to implementation in the state. The report also cites the Midwest Governors Association proposal that states either unitize pore space or declare the pore space below 2,500 feet not associated with hydrocarbon development as accessible for public use.³⁷

Water Rights

Landowners adjacent to streams or rivers enjoy riparian rights to reasonable use of the water. The West Virginia Supreme Court of Appeals adopted the riparian doctrine for surface water in *Gaston v. Mace*, 33 W. Va. 14, 10 S.E. 60 (1889). The Court explained that “[r]easonable use is the touchstone for determining the rights of the parties.”³⁸

West Virginia adopted the “American Rule,” or reasonable use rule, for groundwater rights in *Pence v. Carney*, 58 W. Va. 296, 52 S.E. 702, 706 (1905). The reasonable use rule grants the right to use the water to the owner of overlying land who is able to withdraw the groundwater. However, the use is legally protected only if it is (1) made on the overlying tracts and (2) a “reasonable” use.³⁹

Lithium Ownership and Extraction

Although there are trace elements of lithium in West Virginia coals, no case law or statutory provisions exist.

Classification of CO₂: Commodity and Pollutant

West Virginia classifies carbon dioxide as a pollutant within its limited regulatory framework for carbon capture and sequestration.⁴⁰ These provisions acknowledge increasing pressure to reduce CO₂ emissions and provide for an inventory and plan for CO₂ emissions for compliance with federal law.⁴¹

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The West Virginia Department of Environmental Protection (“WVDEP”) holds broad, perhaps exclusive, authority to regulate oil and gas operations in the state.⁴² The state consolidates environmental regulatory

Report%20-%20June%2030,%202011.pdf.

³⁷ REPORT TO THE LEGISLATURE, *supra* note 31, at 105.

³⁸ *Gaston v. Mace*, 10 S.E. 60 (W. Va. 1889).

³⁹ *Pence v. Carney*, 52 S.E. 702, 706 (W. Va. 1905).

⁴⁰ W. VA. CODE ANN. §§ 22-11A-1, et seq.

⁴¹ W. VA. CODE ANN. §§ 22-5-19, 22-5-20.

⁴² W. VA. CODE ANN. §§ 22-1-1(a)(2), § 22-6-2(c)(12) (West 2020).

programs, including oil and gas regulation, within the WVDEP.⁴³

The Secretary of the WVDEP holds the authority to promulgate rules, enforce relevant statutes, and “[p]erform all duties as the permit issuing authority for the state in all matters pertaining to the exploration, development, production, storage and recovery of th[e] state’s oil and gas.”⁴⁴ The Oil and Gas Conservation Commission sets spacing requirements for deep wells and makes rules to prevent waste and protect correlative rights.⁴⁵ The Oil and Gas Conservation Commission defines wells in West Virginia as either “deep” or “shallow.” “Deep well” is defined as a well drilled to a formation below the top of the uppermost member of the “Onondaga Group,” other than a shallow well or coalbed methane well.⁴⁶ “Shallow well” refers to a well drilled no deeper than one hundred feet below the top of the “Onondaga Group,” other than a coalbed methane well.⁴⁷ A shallow well may not produce, perforate, or stimulate the Onondaga Group formation or any formation below that group.⁴⁸ In practice, this divides Marcellus Shale wells and virtually all historic oil and gas production activities into “shallow wells,” and reserves future, deeper, wells such as the Utica Shale into “deep wells.” This provides some potential sources of confusion, as Marcellus Shale wells—while considered shallow—are deep enough to support the use of supercritical CO₂, the typical medium for use in CO₂ sequestration projects.⁴⁹

If a shallow well drilling site is above a seam of coal, the owner or the coal estate may file objections in writing with the Director of the West Virginia Department of Environmental Protection, who will notify the chair of the Shallow Well Review Board, who will then review the objection and make a determination on whether to approve a permit for a shallow well.⁵⁰ If the review board advises not to approve the permit, the Director must deny the permit. Prior to a determination by the review board, a conference between the well operator and the coal seam owner shall be held to either agree on the proposed well

location or agree to an alternative location.⁵¹ Similarly, a coal operator may object to a deep well placement with the Director if the well is above a coal seam, and a hearing must be held by the Director prior to an approval or denial of the permit for a proposed deep well.⁵²

Pipeline Regulation

Through certification by OPS, West Virginia inspects and enforces the pipeline safety regulations for intrastate gas and hazardous liquid pipeline operators in the state. The Gas Pipeline Safety Section of the Engineering Division of the Public Service Commission performs this work. Chapter 24B of the West Virginia Code, and the regulations promulgated thereunder, govern gas pipeline safety in the state. By letter dated June 28, 2019, OPS notified the state of deficiencies in the excavation damage prevention law.⁵³ The state was given until September 1, 2021 to correct the deficiencies.⁵⁴ Failure to correct may result in a reduction in PHMSA’s State Base Grant funding.

No particular provisions for CO₂ pipelines could be located. However, gas utility pipelines are categorized as common carriers.⁵⁵

State Environmental Laws

West Virginia obtained primacy for the Class II UIC program under Section 1425 of the SDWA in 1984. The West Virginia Class II UIC program is managed by the Office of Oil and Gas (“OOG”) under Chapter 22 of the West Virginia Code. Article 6 of Chapter 22 contains specific authority, with general authority under Articles 1 and 11. Most of the rules applicable to the Class II UIC program can be found in the West Virginia Legislative Rule Title 47, Series 13, and Title 35, Series 4 “Oil and Gas Wells and Other Wells.” West Virginia does not hold primacy with respect to Class VI injection wells.

“West Virginia, by far, has the longest and most complex series of oil and gas conservation statutes of all of the 50 states.”⁵⁶ The Shallow Gas Well Review Board seeks to ensure the cooperative and “fullest practical . . . recovery” of the oil and natural gas where they are

See also City of Morgantown, No. 11-C-411, 2011 WL 3584376 (W. Va. Cir. Ct. Aug. 12, 2011).

⁴³ W. VA. CODE ANN. § 22-1-1(b)(2) (West 2020).

⁴⁴ W. VA. CODE ANN. § 22-6-2 (West 2020).

⁴⁵ W. VA. CODE ANN. § 22C-9-4(f) (West 2020).

⁴⁶ W. VA. CODE ANN. § 22C-9-2(12) (West 2020). *See also* Katharine Lee Avary, *Geology of the Marcellus Shale*, WEST VIRGINIA GEOLOGICAL & ECONOMIC SURVEY (WVGES), http://www.wvgs.wvnet.edu/www/datastat/WVGES_GeologyMarcellusShale.pdf (last visited Sept. 15, 2020).

⁴⁷ W. VA. CODE ANN. § 22C-9-2(11) (West 2020).

⁴⁸ *Id.*

⁴⁹ NAT’L ENERGY TECH. LABORATORY, CARBON STORAGE FAQs, <https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs>.

⁵⁰ W. VA. CODE ANN. § 22-6-17 (West 2020).

⁵¹ W. VA. CODE ANN. § 22c-8-7(a) (West 2020).

⁵² W. VA. CODE ANN. § 22-6-15 (West 2020).

⁵³ Letter from Massoud Tahamtani, Deputy Associate Director, Policy and Programs, Office of Pipeline Safety, to Michael A. Albert, Chairman, W. Va. Pub. Serv. Comm’n (June 28, 2019), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/safety-awareness/pipeline/9221/wv-signed-notice-inadequacy-letter-2018-ph-19-0112-signed.pdf>.

⁵⁴ *Id.*

⁵⁵ W. VA. CODE ANN. § 24-3-3a (West 2020).

⁵⁶ *See* Bruce M. Kramer, *Compulsory Pooling and Unitization with an Emphasis on the Statutory and Common Law of the Eastern United States*, 27 ENERGY & MIN. L. FOUND. 223, 237 (2007).

produced from the same land.⁵⁷ The Review Board holds limited authority to set spacing requirements and establish drilling units when a coal owner or operator objects to proposed shallow gas recovery efforts.⁵⁸ No other method exists by which a shallow gas well can be statutorily pooled. The statute explicitly excepts enhanced oil recovery.⁵⁹ This exception is the only explicit reference to enhanced oil recovery in the West Virginia Code or in state case law. “Shallow well” is defined in the same way as referred to in The Regulatory Landscape Section.⁶⁰

The Oil and Gas Conservation Commission has the authority to establish drilling units and issue pooling orders for both conventional deep wells and secondary recovery operations.⁶¹ Secondary recovery wells are the only wells for which a minimum percentage of operators and royalty owners must consent to the pooling interests; 75% of each well must consent.⁶²

Partition is also an important component of oil and gas law in West Virginia, given the lack of forced pooling for shallow wells and the requirement that all cotenants agree before the minerals can be developed.⁶³ West Virginia uses the minority rule with respect to the development of co-tenancy property. This rule requires 100% of the co-owners to consent to any action on the property, including oil and gas development.⁶⁴

The West Virginia partition statute grants the right to partition in kind, as opposed to partition by sale, of oil and gas interests to be considered.⁶⁵ Partition allows courts to divide or sell land or mineral interests, where necessary, to resolve problems that arise when concurrent owners cannot agree on the proper use or development of the land. Anecdotal evidence suggests that energy companies often purchase the interest of one owner in order to be able to file a partition action to acquire the interests of the remaining owners. However, courts in the state have struggled to apply partition principles to oil and gas cases.

The West Virginia legislature passed the Co-tenancy Modernization and Majority Protection Act in 2018 in response to the difficulties with partition and the

lack of forced pooling.⁶⁶ Under the Act, if there are seven or more royalty owners, the operator makes reasonable efforts to negotiate with all royalty owners in an oil or natural gas mineral property; and, if the royalty owners vested with at least three-fourths of the right to develop, operate, and produce oil, natural gas, or their constituents consent to the lawful use or development of the oil or natural gas mineral property, then the minerals may be developed.⁶⁷ The statute has been compared to forced pooling for a single parcel.

Industrial Siting Requirements

No relevant industrial siting requirements relative to CO₂-EOR or CO₂ pipelines could be located. West Virginia has requirements for solid waste facilities that include siting, location, design, construction, installation, establishment, financial assurance, permitting, modification, operating, groundwater monitoring, and closure and post-closure care.⁶⁸

Local Regulation

State regulation of oil and gas development largely preempts local regulation of oil and gas development. Local governments may not ban those activities.⁶⁹ However, no case law exists as to the extent by which local governments can reasonably regulate these activities through zoning. The West Virginia Code provides that “essential utilities and equipment” are a permitted use in any zoning district.⁷⁰ “Essential utilities and equipment” include underground gas systems including mains, drains, and conduits.⁷¹ No case law exists, but the structure of the act appears to include only transmission facilities, not generation or storage facilities.

Tribal Land

There are no state or federally recognized tribes in West Virginia.

Eminent Domain:

West Virginia Code Section 54-1-2(a) prescribes the purposes for which private property may be taken or damaged for public use by entities and governments other

⁵⁷ W. VA. CODE ANN. § 22C-8-1 (West 2020).

⁵⁸ W. VA. CODE ANN. § 22C-8-5 to § 22C-8-11 (West 2020).

⁵⁹ W. VA. CODE ANN. § 22C-8-3 (West 2020).

⁶⁰ W. VA. CODE ANN. § 22C-8-2(21) (West 2020).

⁶¹ W. VA. CODE ANN. § 22C-9-7 to § 22C-9-8 (West 2020); *See also* James E. McDonald, *Statutory Pooling and Unitization in West Virginia: The Case for Protecting Private Landowners*, 118 W. VA. L. REV. 439, 460 (2015).

⁶² W. VA. CODE ANN. § 22C-9-8 (West 2020).

⁶³ *See, e.g.,* McDonald, *supra* note 51.

⁶⁴ *Law v. Heck Oil Co.*, 145 S.E. 601, 602 (W. Va. 1928).

⁶⁵ *See Consolidated Gas Supply Corp. v. Riley*, 247 S.E.2d 712, 716 (W. Va. 1978).

⁶⁶ W. VA. CODE ANN. § 37B-1-1 *et seq.* (West 2020).

⁶⁷ W. VA. CODE ANN. § 37B-1-4(a) (West 2020).

⁶⁸ W. VA. CODE ANN. § 22-15-1 *et seq.* (West 2020).

⁶⁹ *See generally* *EQT Production Co. v. Wender*, 870 F.3d 322 (4th Cir. 2017) (striking down a Fayette County, West Virginia zoning ordinance that banned the storage of fracking wastewater within the county). *See also* *Ne. Nat. Energy, L.L.C. v. City of Morgantown*, No. 11-C-411, 2011 WL 3584376 (W. Va. Cir. Ct. August 12, 2011) (striking down Morgantown’s ban of fracking within city limits and within one mile of city limits).

⁷⁰ W. VA. CODE ANN. § 8A-7-3(e) (West 2020).

⁷¹ W. VA. CODE ANN. § 8A-A-1-2(f) (West 2020).

than the United States and the State of West Virginia.⁷² Subparagraph (3) includes the authority to condemn “for underground storage areas and facilities, and the operation and maintenance thereof, for the injection, storage and removal of natural gas in subterranean oil and/or gas bearing stratum.”⁷³ CO₂ storage is not specifically mentioned, so it is likely not authorized.

West Virginia Code Section 54-1-2(a)(4) covers water plants and systems and provides broad authority for condemnation for water supply systems, pipelines, and associated facilities.⁷⁴ In addition, condemnation may be used to protect water quality under that provision.

The State of West Virginia may exercise eminent domain “for any and every other public use, object and purpose not herein specifically mentioned, but in no event may “public use,” for the purposes of this subdivision, be construed to mean the exercise of eminent domain primarily for private economic development.”⁷⁵ The United States of America may exercise eminent domain “for each and every legitimate public use, need and purpose of the government of the United States, within the purview, and subject to the provisions of chapter one of this code.”⁷⁶ The 2006 amendments, in response to *Kelo*,⁷⁷ make clear that the State of West Virginia and its political subdivisions may not exercise eminent domain for the primary purpose of “private economic development.” CO₂-EOR/CCS likely falls outside of this prohibition.

No case law exists, but West Virginia Code Section 54-1-2(a)(4) appears to give authority for condemnation for municipal water. Interestingly, West Virginia Code Section 54-1-10 expressly grants railroads the right to exercise eminent domain to take water itself for the operation of its engines.⁷⁸

West Virginia Code Section 54-1-2(a)(3) gives broad condemnation authority with respect to subsurface areas.⁷⁹ Section 54-1-2(a)(3) includes the authority to condemn:

for underground storage areas and facilities, and the operation and maintenance thereof, for the injection, storage and removal of natural gas in

⁷² See W. VA. CODE ANN. § 54-1-2(a) (West 2020).

⁷³ See W. VA. CODE ANN. § 54-1-2(a)(3) (West 2020).

⁷⁴ See W. VA. CODE ANN. § 54-1-2(a)(4) (West 2020).

⁷⁵ W. VA. CODE ANN. § 54-1-2(11) (West 2020).

⁷⁶ *Id.*

⁷⁷ See *Kelo v. City of New London*, 545 U.S. 469 (2005) (holding that economic development constitutes a valid public use to justify the use of eminent domain).

⁷⁸ See W. VA. CODE ANN. § 54-1-10 (West 2020).

⁷⁹ See W. VA. CODE ANN. § 54-1-2(a)(3) (West 2020).

subterranean oil and/or gas bearing stratum, which, as shown by previous exploration of the stratum sought to be condemned and within the limits of the reservoir proposed to be utilized for such purposes, has ceased to produce or has been proved to be nonproductive of oil and/or gas in substantial quantities, when for public use, the extent of the area to be acquired for such purpose to be determined by the court on the basis of reasonable need therefor.⁸⁰

CO₂ Storage Regulation for EOR and Incremental Storage:

Chapter 22, Article 11A of the West Virginia Code sets forth provisions for the permitting of CO₂ storage facilities in West Virginia.⁸¹ The statutory requirements are currently relatively minimal but do require permit approval of the West Virginia Department of Environmental Regulation prior to conducting any carbon dioxide sequestration. Specifically, West Virginia Code Section 22-11A-5 requires a sequestration permit application to describe the: (i) plans and procedures for environmental surveillance, detection, prevention and control; (ii) site and facilities description; (iii) injection well design and mechanical testing plans; (iv) monitoring plan for any injected carbon dioxide to assess and ensure the retention of the carbon dioxide in the sequestration site; (v) plan to provide proof of notice to surface owners, mineral claimants and other owners of record of subsurface interests regarding the contents of the permit application; and (iv) “proof of bonding or financial assurance to ensure that carbon dioxide sequestration sites and facilities will be constructed, operated and closed” in accordance with any future promulgated rules.

A carbon sequestration working group was also established under the provisions of Chapter 22, Article 11A, and the final report of the working group is available in the footnote below.⁸² The Geology and Technical Subcommittee concluded that the potential for sequestration exists in the state. The Midwest Regional Carbon Sequestration Project (MRCSP) in its Phase I

⁸⁰ *Id.*

⁸¹ See W. VA. CODE ANN. § 22-11A-1 et seq. (West 2020).

⁸² *Report to the Legislature*, THE W. VA. CARBON DIOXIDE SEQUESTRATION WORKING GROUP, W. VA. DEP’T OF ENVTL PROT., (July 2011) <https://dep.wv.gov/executive/Documents/WVCCS%20Working%20Group%20Final%20Report%20-%20June%2030,%202011.pdf>.

report estimated the potential at about 60,810 million metric tons.⁸³ This estimation includes storage potential in shale. This estimation includes storage potential in shale. The Legal Subcommittee focused on property ownership and acquisition and concluded that the cost of acquisition poses a substantial barrier to CO₂ storage in the state. At one site alone, approximately 20,000 surface owners and 1,000 mineral owners exist. Conservatively, title examinations alone would cost \$100 million. Add to this cost the cost of compensation to landowners and transaction costs, leading to the conclusion that alternative strategies must be pursued. The subcommittee concluded that use of pore space below 2,500 feet, which arguably avoids the need for compensation, should be explored.

In addition, Chapter 22, Article 9 of the West Virginia Code sets out various provisions applying to ‘gas storage reservoirs.’ Presumably, these provisions would also apply to any CO₂ storage project because the statutes apply to ‘gas’ meaning “any gaseous substance.”⁸⁴ These statutes generally require anyone who “proposes to inject or store gas” to file a map and data with the West Virginia Department of Environmental Protection showing: (i) the location, strata and boundaries of the proposed storage reservoir; (ii) the location of all known oil and gas wells which have been drilled into or through the storage stratum along with detailed information pertaining to said wells; and (ii) a statement as to the use of the storage reservoir, methods of injection and storage along with maximum contemplated pressures.⁸⁵ Such map and requisite data filings are required to be “amended or supplemented semiannually in case any material changes have occurred.” (cite id). The statutes impose additional substantive and approval requirements for storage reservoirs underlying or within two thousand linear feet of an operating coal mine.⁸⁶



“The statutes impose additional substantive and approval requirements for storage reservoirs underlying or within two thousand linear feet of an operating coal mine.”

⁸³ WICKSTROM, L.H. ET AL., CHARACTERIZATION OF GEOLOGIC SEQUESTRATION OPPORTUNITIES IN THE MRCSP REGION, PHASE I TASK REPORT PERIOD OF PERFORMANCE, DOE/NETL DE-PS26-05NT42255 (Oct. 2003 – Oct. 2005).

⁸⁴ W. Va. Code Ann. § 22-9-1(5).

⁸⁵ See W. Va. Code Ann. § 22-9-2.

⁸⁶ See W. Va. Code Ann. § 22-9-5.

WYOMING

Executive Summary

Wyoming is one of two states with primacy over Class I-VI UIC wells. Wyoming law and regulations address numerous aspects of CO₂-EOR and geologic storage. Wyoming has a well-established history of tertiary recovery operations, growing CO₂ pipeline infrastructure, and two developed commercial CO₂ capture facilities. Furthermore, Wyoming has clear laws governing split estates and pore space ownership. Despite this, the significant amount of federal land in Wyoming and Wyoming courts' intent-based approach to interpretation of conveyances of interests in land and minerals—including pore space and CO₂—may complicate efforts to transition CO₂-EOR projects to incremental geologic storage or to resolve conflicts between multiple surface and mineral estates. As a result, a detailed title examination and judicial review may be required to determine ownership and priority within any specific parcel. Owners of concurrent estates in the same property are customarily permitted to use their property provided it does not substantially interfere with or diminish the rights of others to the same resource and does not create waste. Where conflicts exist, subsequent users may be required to accommodate earlier established uses.

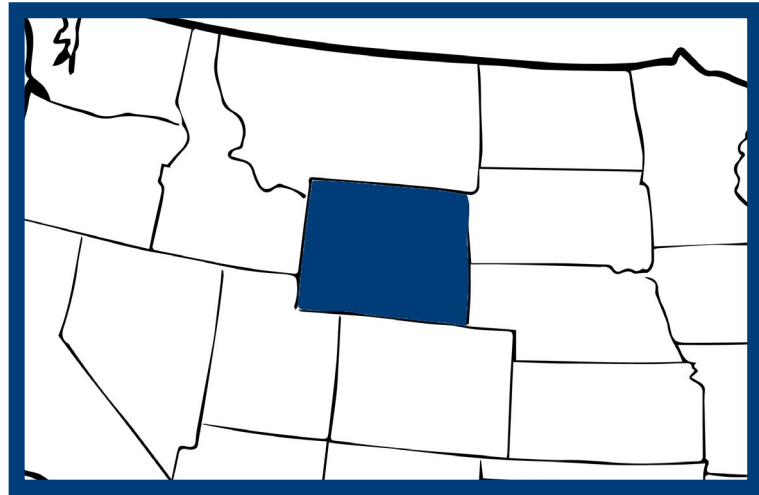
Background:

Wyoming includes federal, state, fee, and tribal land. Wyoming includes 2.2 million acres of tribal land on the Wind River Reservation. Nearly half of Wyoming's land (48.19%) is federal land. In southern Wyoming, much of this land is checkerboarded in alternating 1 square mile sections. There are an additional 11.6 million acres of federal split estate lands with private surface and federal minerals. These ownership patterns mean that most projects in the state cannot be developed without the inclusion of federal surface land or minerals.

Wyoming has a common law legal system. The district courts are the trial courts of general jurisdiction. It has 23 district courts and nine judicial districts. The Wyoming supreme court is the highest court in the state. There is no intermediary appellate court.

CO₂-EOR in Wyoming:

CO₂-EOR in Wyoming began in the early 1980s. Currently there are two developed sources of anthropogenic CO₂ in the state—the Shute Creek Gas Plant and the ConocoPhillips Gas Plant at Lost Cabin. CO₂ from the Shute Creek plant serves seven commercial CO₂-EOR projects in Wyoming. Over 90% of these projects are located on federal land. As of 2018, these projects have cumulatively recovered ~153 million



barrels of incremental oil and injected four trillion cubic feet (229 million tons) of CO₂.¹ Additionally, 43 thousand barrels of incremental oil production have been recovered from 23 separate CO₂-EOR pilot tests in Wyoming.² The Lost Cabin site currently does not serve any CO₂-EOR Projects due to lack of compression. Additionally, some CO₂ is currently transported from Wyoming to the Bell Creek Field in Montana.

Wyoming has a significant opportunity for additional incremental oil production through CO₂-EOR. This potential is presently constrained by CO₂ availability and proximity to existing CO₂ infrastructure. The Enhanced Oil Recovery Institute (“EORI”) has developed a list of 100 suitable candidate fields in Wyoming that are amendable to tertiary recovery efforts and which include estimated recoverable reserves of approximately 1.5 billion barrels of oil.³ The 28 most likely candidate fields would require an additional two trillion cubic feet of CO₂ and contain an estimated 280 million barrels of incrementally recoverable reserves.⁴ The Wyoming legislature has advanced several initiatives to encourage additional investments in CO₂ capture and transportation infrastructure. In 2020, the legislature passed a bill authorizing cost recovery and a higher return on equity for public utility investments in carbon capture, utilization, and storage technology.⁵ Additionally, Wyoming is in the process of creating a pipeline corridor with the goal of expanding its pipeline infrastructure for natural gas and other associated natural resources, including CO₂.⁶

¹ Jones, N., Whitaker, S., & Freye, A., *An Overview of CO₂-EOR in Wyoming 2018*, EORI Bulletin, #1901/2019, ENHANCED OIL RECOVERY INSTITUTE (2019).

² *Id.*

³ *Id.*

⁴ *Id.*

⁵ H.B. 200, 65th Leg., Budget Sess., 2020 Wyo Sess. Laws ch. 144 (Wyo. 2020).

⁶ WYO. STAT. ANN. § 39-14-205 (West 2020).

Land Use, Mineral, Water, and Pore Space Rights:

Mineral Rights

Wyoming courts have consistently followed the rules of contract interpretation to determine the intent of the parties to conveyances and reservations of mineral interests.⁷ That intent is determined from using a four corners approach in which clear and unambiguous language of the document, considering the entire instrument, is given its apparent effect. However, Wyoming courts have noted that when interpreting contracts, particularly those related to minerals, courts should also consider the facts and circumstances surrounding the execution of those contracts, including terms that are used by a particular trade when both parties are involved in that trade.⁸

Consistent with its intent approach to interpreting instruments, the Court has resolved conflicts regarding ownership of various mineral attributes based on an analysis of the “general intent of the parties, concentrating on the purposes of the grant in terms of respective manner of enjoyment of surface and mineral estates.”⁹ Instruments granting or reserving minerals may include named substances such as “coal,” “gas,” or “oil and gas,” and general grants such as “other minerals” or “other hydrocarbons.” Whereas the majority of substances unequivocally fall into one category or another, at times grants and reservations of specific substances can seem in conflict as applied to a specific substance. The outcome is based closely on the intent of the parties as indicated by the specific language of the conveyance. For instance, in *Newman v. Rag*,¹⁰ the court looked at numerous facts and circumstances contemporaneous with the grant of a coal lease to determine whether it included CBM. Similarly, in *Miller Land & Mineral Co v. State Highway Commission*,¹¹ the Wyoming Supreme Court applied its standards of interpretation to determine that gravel was not a mineral, and thus could not be included in mineral reservations. While rejecting definitions developed in federal case law and administrative rules, the court adopted the “ordinary and natural meaning test” as applied to general grants in mineral conveyances.¹² Wyoming courts have not found

natural CO₂ to be either oil, gas, or “other mineral” as a matter of law, and thus ownership would be determined based on the intent or the parties.

“Wyoming has recognized that a mineral interest is an interest in real property and consists of various rights or “incidents” associated with and necessary to the production of oil and gas.”

Wyoming has recognized that a mineral interest is an interest in real property and consists of various rights or “incidents” associated with and necessary to the production of oil and gas.¹³ Thus, a conveyance of the minerals not only conveys the right to capture the physical substance but certain rights necessary to the extraction and enjoyment of the conveyed mineral estates. These rights include “the right to develop, the right to lease, the right to receive bonus payments, the right to receive rentals, and the right to receive royalty payments.”¹⁴ Each of these can be separately alienated and conveyed. The rule of perpetuities has not been applied to extinguish grants of oil and gas top leases in Wyoming.¹⁵

As a result of the free alienability of mineral interests, it is possible for land to involve numerous split estates. For instance, surface, coal, oil, gas, hardrock minerals, and pore space are all separately alienable. In addition, certain rights such as royalty and executive rights may be alienated from those interests. Conflicts between competing subsurface and surface-mineral interests are resolved using a scheme which favors the accommodation doctrine.¹⁶ For conflicts involving state land, the Wyoming Board of Land Commissioners Rules and Regulations

⁷ *Boley v. Greenough*, 2001 WY 47, 22 P.3d 854 (Wyo. 2001); *Cheyenne Mining & Uranium Co. v. Fed. Res. Corp.*, 694 P.2d 65 (Wyo. 1985); *Dawson v. Meike*, 508 P.2d 15 (Wyo. 1973); *Caballo Coal Co. v. Fid. Expl. & Prod. Co.*, 84 P.3d 311 (Wyo. 2004).

⁸ *Boley*, at ¶¶ 10-11, 22 P.3d at ; *Caballo Coal Co.*, at ¶ 11, 84 P.3d at 314-17.

⁹ See, e.g., *Newman v. RAG Wyo. Land Co.*, 53 P.3d 540, 546 (Wyo. 2002); *Caballo Coal Co.*, at P.3d at 313; *McGee v. Caballo Coal Co.*, 69 P.3d 908, 910 (Wyo. 2003).

¹⁰ *Newman*, 53 P.3d at 549-50.

¹¹ 757 P.2d 1001, 1004 (Wyo. 1988).

¹² *Id.*

¹³ *Denver Joint Stock Land Bank of Denver v. Dixon*, 122 P.2d 842, 848 (Wyo. 1942).

¹⁴ See *Smith v. B&G Royalties*, 469 P.3d 1206, 1212 (Wyo. 2020).

¹⁵ *Williams v. Watt*, 668 P.2d 620, 633 (Wyo. 1983).

¹⁶ *BTU Western Res., Inc. v. Berenergy Corp.*, 442 P.3d 50, 60 (Wyo. 2019), *aff'g Berenergy Corp. v. BTU Western Resources, Inc.*, No. 34642, 2015 WL 13240305 at *10 (Wyo. Dist. Apr. 1, 2015) (*citing Belle Fourche Pipeline Co. v. State*, 766 P.2d 537, 544 (Wyo. 1988); WYO. RULES & REGS. BD. LAND COMM'NRS, ch. 18, § 18; ch. 19, § 18 (2020)).

“Land Rules”) encourage accommodation and give priority to the first user, so long as the a subsequent lessee can conduct operations without substantially “interfering with or raising the cost[s]” of the first lessee or “materially reducing the amount or value of the resources” produced by the first lessee.¹⁷ In rare cases, if the proposed benefits from the operations of the second lessee are clearly more beneficial than those of the first lessee the Director may require the first lessee to terminate operations with payment for value lost.¹⁸ Although the issue has not yet been adjudicated, multiple mineral conflicts arising out of grants and conveyances between coal and oil and gas interests in private land would be resolved according to the rules of contract interpretation and would be subject to the accommodation doctrine.¹⁹

Split Estates

In Wyoming and most other states, the mineral estate is considered to be the dominant estate such that a “mineral lessee is entitled to possess that portion of the surface estate reasonably necessary to the production and storage of the mineral.”²⁰ However, Wyoming modified this common law doctrine with passage of the Wyoming Split Estate Act of 2005.²¹

The Split Estate Act requires the mineral developer to “reasonably accommodate existing surface use”²² and, prior to development, to either reach a surface use agreement with the surface owner or to post a surety bond with the Wyoming Oil and Gas Conservation Commission (“WOGCC”) in order to secure payment for any surface damages that may occur in the event that surface use agreement negotiations are ultimately unsuccessful.²³ The WOGCC requires the surety bond to be posted in an amount equal to \$10,000 per permitted wellbore with such bond covering all anticipated surface damages related to the oil and gas operations (including EOR operations), including those for well pads, pipelines, roads, and facility infrastructure.²⁴ However, the surface

owner is entitled to recover any damages sustained as a result of oil and gas and enhanced recovery operations, and such actual surface damages payable by the oil and gas operator can ultimately exceed the amount of the posted bond.²⁵ At times, particularly where the surface may be intensively developed for residential or renewable energy uses, this compensation requirement may make subsequent mineral development economically impracticable. The implied rights of a mineral owner to use the surface as is reasonably necessary to production of oil or gas would not extend to use of the surface for incremental CO₂ storage or geologic storage operations.

Pore Space Ownership

Wyoming vests pore space ownership with the surface owner by statute.²⁶ Pore space, is defined by the statute as the “subsurface space which can be used as storage space for CO₂ or other substances”²⁷ Wyoming’s statutory declaration, however, is not dispositive with respect to federally reserved minerals or tribal property within state borders. Furthermore, in Wyoming, rights to pore space can be separately conveyed; thus, a title evaluation will be necessary to conclusively determine pore space ownership to any specific parcel. Wyoming recognizes that owners of pore space have “corresponding rights” with respect to use of the pore-space storage capacity for sequestration.²⁸ It is unknown whether these rights would extend to other transboundary uses of pore space.

Both the surface and mineral owners have rights to use and occupy the pore space. The implied right to use the surface for mineral development includes the right to dispose of produced water, subject to limitations on use for the benefit of extralateral parcels, and to dispose of water or CO₂ as part of enhanced recovery operations. Wyoming’s pore space declaration does not change this well-established common law rule.²⁹ Injection operations into the pore space for geologic storage, gas storage, or chemical disposal require rights from the surface owner. The majority of injection wells are permitted by the Wyoming Department of Environmental Quality pursuant to the Underground Injection Control Program.³⁰ Class II wells, which are the majority of injection wells for CO₂-EOR are subject to regulation by the WOGCC.³¹

¹⁷ WYO. RULES & REGS. BD. LAND COMM’NRS ch. 18, § 18(c); ch. 19, § 18(c) (2020).

¹⁸ WYO. RULES & REGS. BD. LAND COMM’NRS ch. 18, § 18(d)(iii)-(iv); ch. 19, § 18(d)(iii)-(iv) (2020).

¹⁹ *Berenergy Corp. v. BTU Western Res., Inc.*, Civ. No. 34642, 2018 WL 7107276 at *2 - *3 (D. Wyo. June 11, 2018).

²⁰ *Mingo Oil Producers v. Kamp Cattle Co.*, 776 P.2d 736, 741 (Wyo. 1989).

²¹ See WYO. STAT. ANN. §§ 30-5-401 through 30-5-410 (2020). The Wyoming Split Estate Act is also applicable to enhanced oil recovery operations.

²² WYO. STAT. ANN. § 30-5-402(a) (West 2020).

²³ See WYO. STAT. ANN. § 30-5-402(c) (West 2020).

²⁴ See WYO. STAT. ANN. § 30-5-404(b) (West 2020); see also *Fox Creek Land & Livestock*, No. 5194-2019 (Wyo. Oil & Gas Conservation Comm’n Mar. 10, 2020); *Brw East, LLC Obj. to EME Bond*, No. 6560-2019 (Wyo. Oil & Gas Conservation Comm’n Mar. 10, 2020).

²⁵ See WYO. STAT. ANN. § 30-5-404(c) (West 2020); WYO. STAT. ANN. § 30-5-404(e) (West 2020).

²⁶ WYO. STAT. ANN. § 34-1-152 (West 2020).

²⁷ WYO. STAT. ANN. § 34-1-152(d) (West 2020).

²⁸ WYO. STAT. ANN. § 34-11-314 (West 2020).

²⁹ WYO. STAT. ANN. § 34-1-152(e) (West 2020).

³⁰ See generally, WYO. RULES & REGS. ENVTL QUALITY ch. 27 (2020).

³¹ WYO. RULES & REGS. Oil Gen ch. 4, §§ 7-10 (2020).

Water Rights

Wyoming is an appropriation state in terms of water administration. The Wyoming State Constitution establishes: (1) any water, except such water that is defined to be percolating water, is property of the state held in trust for the people of the state;³² (2) priority of appropriation is the guiding doctrine of Wyoming water law;³³ (3) water subject to appropriation under the State Constitution is any water (surface or ground) which would naturally reach a stream;³⁴ (4) only beneficial uses of water may give rise to an appropriation;³⁵ (4) an appropriation of water typically may not be denied if there is available water to appropriate;³⁶ and that (5) the Board of Control is responsible for regulating the appropriation, distribution and diversion of Wyoming's waters.³⁷ Generally, water rights in Wyoming are tied to a specific type of beneficial use and cannot be separately conveyed or severed from the lands in which they are used;³⁸ however, there are procedures for permanent or temporary changes of use and it is relatively common for the Board of Control, through the State Engineer's Office, to approve temporary changes of use to benefit oil and gas drilling and enhanced recovery operations.³⁹

While "percolating water," was generally considered to be "waste" or "seepage" water at common law,⁴⁰ water produced during oil and gas operations is considered "by-product water" and is subject to appropriation under Wyoming statutory law.⁴¹ Specifically, any "person intending to appropriate by-product water for beneficial use shall file an application with the state engineer on the forms and in the manner prescribed for groundwater applications."⁴²

Although all non-percolating water is property of the state, following prior appropriation for beneficial purposes there is a property interest in the "right to use that water."⁴³ Therefore, any municipal or governmental condemnation of such appropriated water rights requires "just compensation."⁴⁴ Specifically, water rights "may be

condemned to supply water for such preferred" public and semi-public purposes, including and in the following order: (i) water for human and livestock drinking purposes; (ii) water for municipal purposes; (iii) water for railway, culinary, laundry, bathing and refrigerating uses; and (iv) water for industrial purposes.⁴⁵

Lithium Ownership and Extraction

Our search did not reveal any laws or regulations in Wyoming with respect to lithium extraction. Wyoming is believed to potentially have substantial lithium brine deposits which could be recovered in association with CCUS, though the economics of the extraction of such deposits appear to be a hurdle.⁴⁶ Based on Wyoming's approach to interpreting conveyances and reservations of minerals, lithium is unlikely to be considered oil or gas, but will likely be included in conveyances or reservations of "other minerals" in the absence of indication of intent to the contrary. Disposal and storage of brines may be subject to regulation by the Oil and Gas Conservation Commission and Department of Environmental Quality. Lithium is a locatable mineral under federal law.⁴⁷ Potential conflicts between lithium recovery operations and those for CO₂-EOR would likely be resolved according to Wyoming law regarding conflicts between mineral uses.

Classification of CO₂: Commodity and Pollutant

Wyoming classifies CO₂ as both a commodity and a pollutant. For purposes of taxation and revenue, CO₂ is classified as a gas and is subject to severance tax.⁴⁸ Severance taxes paid on CO₂ may be deducted from those paid on tertiary oil produced.⁴⁹ CO₂ is also classified as a commodity—a gas and an associated natural resource—for purposes of the Office of State Lands and Investments and the Wyoming Pipeline and Infrastructure Authority.⁵⁰

CO₂ is also classified as an air pollutant and greenhouse gas for purposes of the Wyoming Department of Environmental Quality air quality regulatory program.⁵¹

³² WYO. CONST. art. 8 § 1.

³³ WYO. CONST. art. 8 § 3.

³⁴ See *Bower v. Big Horn Canal*, 307 P.2d 593, 602 (Wyo. 1957).

³⁵ WYO. CONST. art. 8 § 3.

³⁶ *Id.*

³⁷ WYO. CONST. art. 8 § 2.

³⁸ See WYO. STAT. ANN. § 41-3-101 (West 2020).

³⁹ WYO. RULES & REGS. STATE ENGINEER, Surface Water ch. 4; see also Wyo. State Engineer, Temporary Water Use Agreement form available at <http://seo.wyo.gov/applications-forms#Surface> (last visited Apr. 28, 2020).

⁴⁰ See *Binning v. Miller*, 102 P.2d 54, 61 (Wyo. 1940).

⁴¹ See WYO. STAT. ANN. § 41-3-903 (West 2020).

⁴² WYO. STAT. ANN. § 41-3-904(a) (West 2020).

⁴³ *Johnston v. Little Horse Creek Irr. Co.*, 79 P. 22, 24 (Wyo. 1904).

⁴⁴ See WYO. CONST. art. 1, § 33; *Bush Land Dev. Co. v. Crook Cty Weed and Pest Cont. Dist.*, 388 P.3d 536, 540 (Wyo. 2017).

⁴⁵ See WYO. STAT. ANN. § 41-3-102 (West 2020).

⁴⁶ See, Karl G. Taboga, et. al, *Lithium Resources in Wyoming*, Wyoming State Geological Survey Report, of Investigations No. 69, (2015); Department of Fossil Energy, *DOE-Sponsored Project Shows Huge Potential for Carbon Storage in Wyoming* (June 3, 2014) <https://www.energy.gov/fe/articles/doe-sponsored-project-shows-huge-potential-carbon-storage-wyoming>; John C.K. Daly, *Researchers Have Stumbled on a Massive Lithium Mine That Could Meet All US Demand*, OILPRICE.COM, (Apr. 29, 2013) <https://www.businessinsider.com/new-wyoming-lithium-deposit-could-meet-all-us-demand-2013-4>.

⁴⁷ 30 U.S.C.A. § 22 (West 2020).

⁴⁸ WYO. STAT. ANN. § 39-14-201 (West 2020).

⁴⁹ WYO. STAT. ANN. § 39-14-205 (West 2020).

⁵⁰ WYO. STAT. ANN. § 36-6-301 (West 2020); Wyo. Stat. § 39-14-205 (West 2020).

⁵¹ WYO. RULES & REGS. ENVTL QUALITY ch. 1, § 3 (West 2020).

Regulation of CO₂-EOR and CO₂ Pipelines:

Oil and Gas Conservation Regulation

The WOGCC has broad authority to oversee oil and gas development in Wyoming and is charged with the regulation of “all aspects of oil mining operations.”⁵² “Oil mining operations means operations associated with the production of oil or gas from reservoir access holes drilled from underground shafts or tunnels.”⁵³ Specifically, the WOGCC regulates seismic activities, the drilling and plugging of oil and gas wells, the chemical treatment or stimulation of wells, injection wells, the spacing of wells, disposal of produced water and drilling fluids and all aspects of oil and gas unitization and enhanced recovery methods.⁵⁴ Although the rule of capture generally applies to oil and gas operations in Wyoming,⁵⁵ it has been modified by the Oil and Gas Conservation Act and the WOGCC regulates oil and gas production activities for the purposes of preventing waste, protecting correlative rights, and protecting the public health, safety, and welfare.⁵⁶

all royalty owners and 80% of all working interest owners within the proposed unit area must approve or ratify such proposed unit plan of operations (both may be reduced to 75% upon application and WOGCC approval).⁵⁹ In addition, the WOGCC, in consultation with the Wyoming Department of Environmental Quality, has been delegated statutory authority to regulate CO₂ storage incidental to enhanced recovery operations.⁶⁰ Although the WOGCC authorizes unitization for injection, subsurface trespass may still result. Wyoming courts have held that receipt of an injection permit or approval of an administrative unit is not a defense against subsurface trespass or conversion resulting therefrom.⁶¹ Wyoming’s unitization laws and regulations do not differentiate between oil and gas or conventional and shale resources.

Similar to other conventional oil and gas operations, an operator is required to maintain a general bond for enhanced recovery operations.⁶² CO₂-EOR operations are also subject to reporting and monitoring requirements including the substances injected, volume injected, production, and sales.⁶³ If the storage of CO₂ is merely a result of using CO₂ in enhanced oil or gas recovery, the operator may apply for certification from the WOGCC.⁶⁴ This certification recognizes that there is incidental storage occurring and certifies the quantity being stored.⁶⁵ Wyoming does not have separate laws pertaining to natural gas storage and does not differentiate based on subsurface storage medium.

Pipeline Regulation

The Wyoming Public Service Commission (“WPSC”) is responsible for inspecting and enforcing PHMSA pipeline safety regulations for intrastate natural gas pipeline operators in the State of Wyoming.⁶⁶ However, the WPSC does not have safety jurisdiction for Hazardous Liquids and Interstate Gas Pipelines, which are subject to inspection and enforcement by the Office of Pipeline Safety.⁶⁷

⁵⁹ WYO. STAT. ANN. § 30-5-110(f) (West 2020).

⁶⁰ See WYO. STAT. ANN. § 30-5-502 (West 2020).

⁶¹ ANR Prod. Co. v. Kerr-McGee Corp., 893 P.2d 698 (Wyo. 1995).

⁶² WYO. RULES & REGS. OIL GEN. ch. 3, § 4 (2020).

⁶³ WYO. RULES & REGS. OIL GEN. ch. 3, §§ 13(a), § 43(d), § 46(a); ch. 4, § 10 (2020).

⁶⁴ WYO. STAT. ANN. § 30-5-502(a) (West 2020).

⁶⁵ WYO. STAT. ANN. § 30-5-502(a) (West 2020).

⁶⁶ See WYO. PUB. SERV. COMM’N, *Wyo. Pub. Serv. Comm’n Pipeline Industry*, available at <https://psc.wyo.gov/pipeline> (last visited Apr. 15, 2020).

⁶⁷ *Id.*

“Similar to other conventional oil and gas operations, an operator is required to maintain a general bond for enhanced oil recovery operations.”

A party desiring to conduct water-flooding, CO₂ injection or other enhanced oil recovery operations may apply to the WOGCC for an order approving such unit operations.⁵⁷ The WOGCC then holds a public hearing, hears evidence and ultimately issues an order either accepting or rejecting such proposed enhanced oil recovery unit operations.⁵⁸ However, prior to any order accepting the unit proposal taking effect, at least 80% of

⁵² See WYO. STAT. ANN. § 30-5-104 (West 2020).

⁵³ WYO. STAT. ANN. § 30-5-104(d)(ii)(F) (West 2020).

⁵⁴ See WYO. STAT. ANN. § 30-5-104 (West 2020).

⁵⁵ Union Pacific Resources Co. v. Texaco, Inc., 882 P.2d 212, 223 (Wyo. 1994).

⁵⁶ See WYO. STAT. ANN. § 30-5-104 (West 2020).

⁵⁷ See WYO. STAT. ANN. § 30-5-110 (West 2020).

⁵⁸ *Id.*

State Environmental Laws

The WOGCC's rules pertaining to the regulation of underground injection disposal wells of "fresh water, salt water, brackish water, or other water unfit for domestic, livestock, irrigation, or other general uses" are located in Ch. 4, Section 5,⁶⁸ while rules pertaining to the regulation of injection wells for enhanced recovery operations are located in Ch. 4, Section 7.⁶⁹ Of particular significance, a party seeking approval for such enhanced recovery or disposal wells must demonstrate that the proposed injection will not endanger fresh water sources, that the proposed injection will not initiate fractures of the overlying strata, and that the injection well will meet and maintain specific mechanical integrity requirements.⁷⁰

CO₂-EOR is also regulated through the WOGCC's rules for Class II wells and tertiary production.⁷¹ The UIC program is administered by the Wyoming Department of Environmental Quality ("WYDEQ"), with the exception of such Class II injection wells which are regulated by the WOGCC.⁷² Effective as of December 23, 1982, the EPA approved the WOGCC for primacy for the regulation of Class II UIC wells (the injection of fluids associated with oil and natural gas production) in the State of Wyoming.⁷³ As indicated earlier, and in conjunction with Ch. 4 of the Rules and Regulations of the WOGCC, the WOGCC ensures that "EPA's minimum requirements for construction, operation, monitoring, testing, reporting and closure requirements" for injection wells are met.⁷⁴

More recently, Wyoming was granted primary responsibility for enforcing the regulation of Class VI UIC wells (CO₂ underground injection storage wells). On April 1, 2020, the EPA Administrator signed a proposed rule which initially determined that the State of Wyoming meets the requirements for Class VI UIC well primacy.⁷⁵ On May 29, 2020, EPA concluded its required public comment period on its proposed rule,⁷⁶ and, effective as

of October 9, 2020, the WYDEQ received approval from the EPA for primacy over Class VI UIC well regulation.⁷⁷ In accordance with this delegated authority, the Wyoming Department of Environmental Quality has set up a permitting regime for Class VI wells.⁷⁸

The WYDEQ also maintains permitting, inspection, and monitoring authority relevant to the oil and gas and enhanced oil recovery industries pursuant to its Clean Air Act and Clean Water Act oversight. Specifically, various facilities may require a Title V Clean Air Act Operating Permit which is issued by WYDEQ.⁷⁹ However, the WOGCC is generally responsible for venting and flaring approval in compliance with WYDEQ air quality rules.⁸⁰

Industrial Siting Requirements

Wyoming requires any facility with an estimated construction cost exceeding a certain amount to obtain a permit from the Industrial Siting Council.⁸¹ Additionally, any commercial household, industrial, hazardous, or radioactive waste facility, or any commercial wind or solar electric generation facility to obtain a permit regardless of the cost of the facility.⁸² However, pipelines, except coal slurry pipelines, as well as oil and gas drilling, producing, and wellfield activities and facilities are exempt from Industrial Siting Commission jurisdiction.⁸³ Accordingly, pipelines and injection facilities as part of CO₂-EOR operations are likely exempt from state industrial siting requirements.

Local Regulation

State regulation of oil and gas development largely preempts local regulation of oil and gas development. The Wyoming constitution grants cities and towns home rule powers over local affairs, "subject to statutes . . . uniformly applicable to all cities and towns."⁸⁴ While CO₂-EOR and other oil and gas are subject to reasonable exercise of zoning authority, counties cannot "prevent any use or occupancy reasonably necessary to the extraction or production of the mineral resources in or under any lands subject thereto."⁸⁵

⁶⁸ See WYO. RULES & REGS. OIL GEN. ch. 4, § 5 (2020).

⁶⁹ See WYO. RULES & REGS. OIL GEN. ch. 4, § 7 (2020).

⁷⁰ See WYO. RULES & REGS. OIL GEN. ch. 4, §§ 5; ch. 4, § 7 (2020).

⁷¹ WYO. RULES & REGS. OIL GEN. ch. 1 §§ 2(i), (ggg); ch. 3, §§ 13(a), § 43(d), § 46(a); ch. 4, § 10 (2020).

⁷² WYO. RULES & REGS. OIL GEN. ch. 4, § 7 (2020).

⁷³ See State Underground Injection Control Programs: Wyoming, 47 Fed. Reg. 52434 (proposed Nov. 15, 1982) (codified at 40 C.F.R. 123).

⁷⁴ See WYO. OIL & GAS CONSERVATION COMM'N, *What is a disposal well?*, <http://wogcc.wyo.gov/disposal-wells> (last visited Apr. 15, 2020).

⁷⁵ See Wyoming Underground Injection Control Program; Class VI Primacy, 85 Fed. Reg. 20621 (proposed Apr. 1, 2020) (to be codified at 40 C.F.R. 147) *available at* <https://www.epa.gov/uic/wyoming-proposed-uic-program-revision-class-vi-injection-wells>.

⁷⁶ See Wyoming Underground Injection Control Program; Class VI Primacy, 85 Fed. Reg. 20621 (proposed Apr. 14, 2020) (to be codified at 40 C.F.R. 147) (comments at EPA-HQ-OW-2020-0123).

⁷⁷ 40 C.F.R. § 147.2550 (2020).

⁷⁸ WYO. RULES & REGS. WATER QUALITY ch. 24, § 4 (2020).

⁷⁹ See WYO. DEPT. ENVTL. QUALITY, ABOUT TITLE V, *available at* <http://deq.wyoming.gov/aqd/title-v-operating-permit-program/resources/about-title-v/> (last visited Apr. 16, 2020).

⁸⁰ See WYO. RULES & REGS. OIL GEN. ch. 3, Sec. 39 (2020).

⁸¹ WYO. STAT. ANN. §§ 35-12-102, 106 (West 2020).

⁸² WYO. STAT. ANN. §§ 35-12-102, 106 (West 2020).

⁸³ WYO. STAT. ANN. § 35-12-119 (West 2020).

⁸⁴ WYO. CONST. art. XIII, § 1(b).

⁸⁵ WYO. STAT. ANN. § 18-5-201 (West 2020).

Tribal Land

The Wind River Reservation is located in Wyoming. The Wind River reservation is home to two federally recognized tribes—the Eastern Shoshone Tribe and the Northern Arapaho tribe. The Eastern Shoshone and Northern Arapaho tribes have separate governments, tribal codes, and administrative business councils as well as a joint business council.⁸⁶ The Joint Business Council is responsible for day-to-day management of jointly owned resources and joint programs. There is no state agency or office that serves as a liaison between the state and the tribes.

The Wind River Agency of the BIA is responsible for the administration of the Wind River oil and gas leasing program after authorization and in consultation with the Joint Business Council.⁸⁷ The BLM has primary responsibility for field inspection of oil and gas operations on tribal lands working alongside the Tribal Minerals Department.⁸⁸ Additionally, the EPA is responsible for the implementation of the Reservation's UIC Program for all classes of injection wells.⁸⁹ Accordingly, CO₂-EOR and geologic CO₂ storage operations on tribal land would be federally administered. Our research did not indicate any tribal codes specific to CO₂ storage.

Eminent Domain:

Eminent Domain rights in Wyoming are often defined by whether the taking is being effectuated by a private or public entity. Governmental entities have wide latitude to take private property rights so long as just compensation is provided.⁹⁰ However and according to the Wyoming Constitution, eminent domain for private use is limited to “ways of necessity, and for reservoirs, drains, flumes or ditches on or across the lands of others for agricultural, mining, milling, domestic or sanitary purposes” and only so long as just compensation is provided.⁹¹ The Wyoming Supreme Court has yet to define a “way of necessity”; however, a recent Goshen County District Court Opinion concluded that a “way of necessity” in the context of private eminent domain

⁸⁶ Shoshone & Arapahoe Tribes of the Wind River Reservation Code tit. 14, ch. 13, § 14-13-1 (2020).

⁸⁷ 25 C.F.R. §§ 227, 227.4, 227.5 (2020).

⁸⁸ 25 U.S.C.A. §§ 396a *et seq.* (West 2020); 25 U.S.C.A §§ 23-2101 to 2108 (West 2020); 25 C.F.R. §§ 200-227.3 (2020); Shoshone & Arapahoe Tribes of the Wind River Reservation Code § 11-2-1 *et seq.* (2020).

⁸⁹ See U.S. ENVTL PROT. AGENCY, *Underground Injection Control in Region 8 (CO, Mt, ND, SD, UT, and WY)*, Tribal Programs, available at <https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#primacy> (last visited June 21, 2020).

⁹⁰ See WYO. CONST. art. 1, § 33; *Bush Land Dev. Co. v. Crook Cty. Weed and Pest Cont. Dist.*, 388 P.3d 536, ¶¶ 9-11, 388 P.3d 536, 540 (Wyo. 2017).

⁹¹ WYO. CONST. art. 1, § 32.

is limited to those purposes set forth in Wyo. Stat. § 1-26-815(a).⁹² The Wyoming Supreme Court has found that private eminent domain rights extend to at least include roads, pipelines (including enhanced oil recovery pipelines), and easements for utilities and communication lines.⁹³ Wyoming does not impose common carrier requirements on pipelines developed using condemnation to secure rights-of-way.⁹⁴

The Wyoming Eminent Domain Act, Wyo. Stat. §§ 1-26-501 through 1-26-817, governs condemnation proceedings in Wyoming. Among other provisions, the Act provides for entry prior to a condemnation action for surveying and information gathering purposes⁹⁵ and specifically details condemnation rights of pipeline companies⁹⁶ and other oil, gas, and mineral exploration and development companies.⁹⁷ Condemnation of pore space rights for geologic storage is expressly prohibited.⁹⁸

Geologic CO₂ Storage Regulation and Incremental Storage:

The Wyoming legislature has differentiated storage incidental to enhanced oil recovery from storage for the sole purpose of storing carbon in the pore space.⁹⁹ Wyoming regulates geologic storage operations including unitization of pore space, ownership of injected substances, injection permitting, eminent domain, liability, and monitoring, verification, and reporting.¹⁰⁰

⁹² See Order on Plaintiff's Application for Order to Show Cause and Order Permitting Entry dated May 22, 2020, in the State of Wyoming District Court of the Eighth Judicial District, County of Goshen, Civil Action No. CV-2019-108-DC. This case is currently on appeal to the Wyoming Supreme Court (S-20-0197 and S-20-0198).

⁹³ See *Barlow Ranch Ltd. P'ship v. Greencore Pipeline Co., LLC*, 301 P.3d 75, 99-101 (Wyo. 2013) (CO₂ pipeline easement); *Bridle Bit Ranch Co. v. Basin Elec. Power Co-op*, 118 P.3d 996, 1014-15 (Wyo. 2005) (electric power transmission line); *Wyo. Res. Corp. v. T Chair Land Co.*, 49 P.3d 999, 1003-04 (Wyo. 2002) (access road for oil and gas development); *WYMO Fuels Inc. v. Edwards*, 723 P.2d 1230, 1236-37 (Wyo. 1986) (mine haul road); *Canyon View Ranch v. Basin Elec. Power Corp.* 628 P.2d 530, 540-41 (Wyo. 1981) (electric power transmission line); and *Coronado Oil Co. v. Grieves*, 603 P.2d 406, 411-13 (Wyo. 1979) (access road for oil and gas development).

⁹⁴ *Id.*

⁹⁵ See WYO. STAT. ANN. § 1-26-507 (West 2020).

⁹⁶ See WYO. STAT. ANN. § 1-26-814 (West 2020).

⁹⁷ See WYO. STAT. ANN. § 1-26-815 (West 2020).

⁹⁸ WYO. STAT. ANN. § 35-11-316(j) (West 2020).

⁹⁹ WYO. STAT. ANN. §§ 30-5-502; § 35-11-313(b) (West 2020).

¹⁰⁰ WYO. STAT. ANN. § 34-1-153 (West 2020).

The WOGCC has a separate process for the approval of geologic storage units.¹⁰¹ Wyoming permits any interested person to apply for unitization of pore space interests for geologic storage. The applicant must provide a “proposed plan of unitization applicable to the proposed unit area which the applicant considers fair, reasonable and equitable and which shall include provisions for determining the pore space to be used within the area.”¹⁰² Approval of the owners of 80% of the “pore space storage capacity” within the unit area is required (which may be reduced to 75% upon application and WOGCC approval).¹⁰³ Any pore space owner not included within a unitization order but within the unit may petition for inclusion.¹⁰⁴

While the process for obtaining certification for incidental storage is relatively simple, the process for obtaining a permit for the sole purpose of sequestration is more complex and falls under the jurisdiction of the Department of Environmental Quality.¹⁰⁵ To obtain such a permit, the injector must identify the general geology of the area, including the presence of any aquifers in the injection zone.¹⁰⁶ Additionally, the injector must show proof of notice to all surface and mineral owners, lessees, and claimants.¹⁰⁷ The intent of the notice is to give both the surface owner, owning the pore space, and the mineral interest owners an opportunity to protest the permit. The injector must show proof of bonding or other financial assurance and make other showings necessary to ensure the sequestration sites, facilities, and operations will be in accord with the public health and safety.¹⁰⁸

Were a Wyoming operator to transition an asset from CO₂-EOR options to pure geologic storage, it would need to address new regulatory requirements in addition to obtaining new property rights from the surface owner. Once recovery ends or if the recovery efforts “results in an increased risk to an underground source of drinking water as compared to enhanced oil recovery operations” the site may become a geologic sequestration site.¹⁰⁹ Wyoming defines geologic sequestration to mean “the injection of carbon dioxide and associated constituents

into subsurface geologic formations intended to prevent its release into the atmosphere.”¹¹⁰ Once this occurs, regulation of the site is transferred from the WOGCC to the Department of Environmental Quality.¹¹¹

The ownership of all and other substances injected into the pore space for geologic sequestration “shall be presumed to be owned by the injector of such material”¹¹² and title includes “all rights, benefits, burdens and liabilities of such ownership.”¹¹³ To rebut this presumption, it must be shown by a preponderance of the evidence that someone else holds title to the injected substances.¹¹⁴ Additionally, an owner of pore space simply granting permission to inject does not automatically shift title to the owner of the pore space, as both title, benefits, and liabilities presumptively lie with the injector.¹¹⁵ Although the state has created a special revenue account for post closure monitoring and verification, it does not assume liability for geologic storage.¹¹⁶



“The WOGCC has a separate process for the approval of geologic storage units.”

¹⁰¹ WYO. STAT. ANN. §§ 35-11-313 to 318 (West 2020); WYO. RULES & REGS. OIL GEN. ch. 3, § 43 (West 2020).

¹⁰² WYO. STAT. ANN. § 35-11-315 (West 2020).

¹⁰³ WYO. STAT. ANN. § 35-11-316 (West 2020).

¹⁰⁴ *Id.*

¹⁰⁵ WYO. STAT. ANN. § 35-11-313 (West 2020).

¹⁰⁶ WYO. STAT. ANN. § 35-11-313(f)(ii)(A)-(B) (West 2020).

¹⁰⁷ WYO. STAT. ANN. § 35-11-313(f)(ii)(N) (West 2020).

¹⁰⁸ WYO. STAT. ANN. § 35-11-313(f)(ii)(K) (West 2020).

¹⁰⁹ WYO. STAT. ANN. § 35-11-313(c) (West 2020).

¹¹⁰ WYO. STAT. ANN. § 35-11-103(c)(xx) (West 2020).

¹¹¹ WYO. STAT. ANN. § 35-11-313(c) (West 2020).

¹¹² WYO. STAT. ANN. § 34-1-153(a) (West 2020).

¹¹³ WYO. STAT. ANN. § 34-1-153(a) (West 2020).

¹¹⁴ WYO. STAT. ANN. § 34-1-153(a) (West 2020).

¹¹⁵ WYO. STAT. ANN. § 34-1-153(a)-(b) (West 2020).

¹¹⁶ WYO. STAT. ANN. § 35-11-318 (West 2020).

TRENDS

Introduction

CO₂-EOR operations and geologic CO₂ storage operations are subject to numerous, and often complex, statutory, regulatory, and common law rules. Project developers should be aware of, and carry out operations consistent with, these rules. The following summaries and tables consolidate the information contained in the state reports. These tables are not meant to serve as a substitute for the information in the state reports and do not constitute advice as to the applicability of such laws, regulations and policies to any specific situation. Instead, these summaries and tables demonstrate the differences, gaps, and inconsistencies in laws, regulations, and policies applicable to CO₂-EOR and geologic CO₂ operations throughout various states. These gaps and inconsistencies could present obstacles to multi-state projects and/or opportunities for state legislative attention.

Dominance of the Mineral Estate

All states in this report recognize that the surface estate is servient to the mineral estate. The dominance of the mineral estate permits a split-estate mineral owner to access land as is reasonably necessary for production for oil and gas. This right generally includes the right to inject water or CO₂ for purposes of enhanced oil recovery.

However, the dominance of the mineral estate may be subject to state specific statutory and common law limitations and surface protection doctrines including the “reasonable use rule,” or the “accommodation doctrine.” These doctrines generally limit the rights of the mineral owner to engage in surface-destroying activities. While the scope of any given judicial rule or doctrine changes from state to state, all are similar in that they restrict the ability of a mineral operator to interfere with or prevent existing surface operations. Conflicts with surface uses, including renewable energy development and subsurface uses, will likely be resolved according to these rules. The majority of western states have enacted statutory surface protection laws. For instance, Colorado, Illinois, Kentucky, Montana, New Mexico, North Dakota, Tennessee, West Virginia, and Wyoming all have enacted versions of Split Estate Acts or Surface Owner Protection Acts which may entitle the surface owner to notice, compensation, and other procedural protections.

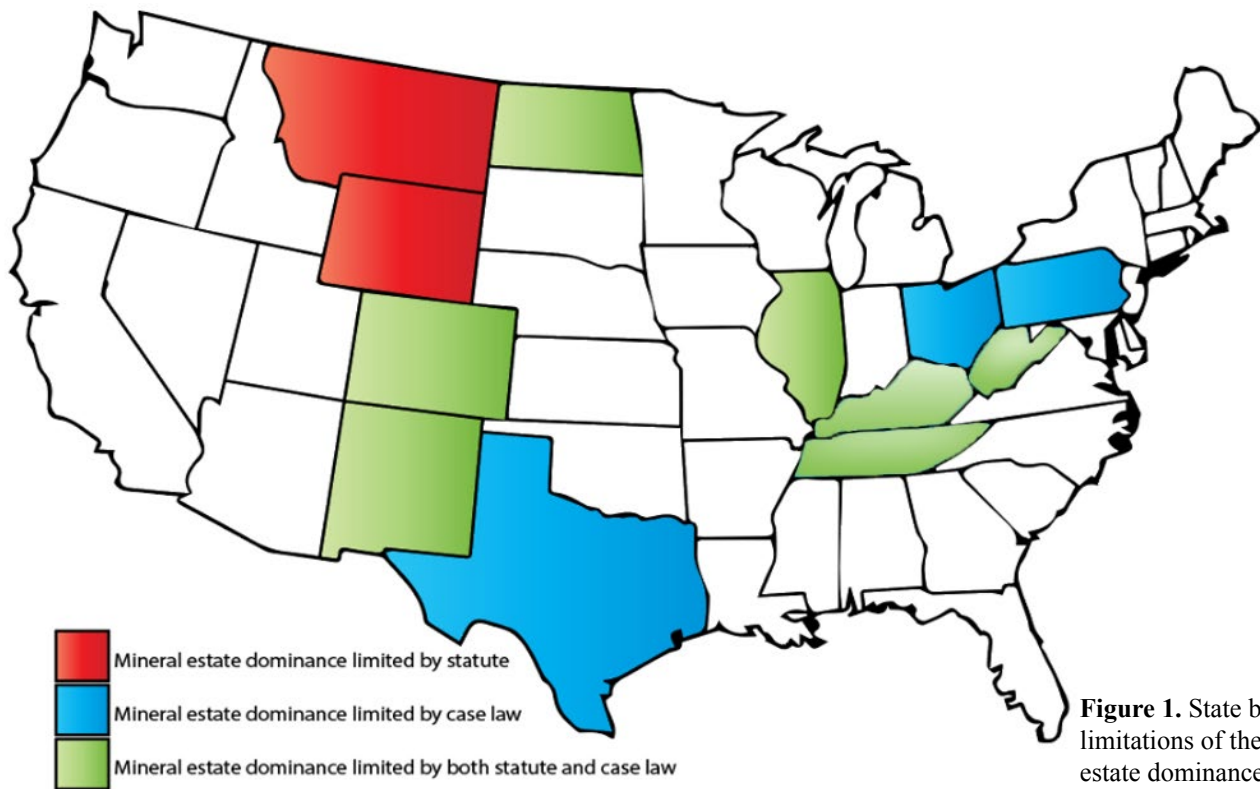


Figure 1. State by state limitations of the mineral estate dominance.

Dominance of the Mineral Estate			
	Dominant Nature of Mineral Estate	Dominance Limited by Case Law	Split Estate or Surface Owner Protection Act
CO	Gerrity Oil & Gas Corp. v. Magness, 946 P.2d 913 (Colo. 1997).	Reasonable Use Rule, Gerrity Oil & Gas Corp. v. Magness, 946 P.2d 913 (Colo. 1997).	COLO. REV. STAT. ANN. § 35-60-127 (West 2020).
IL	<i>See</i> Jilek v. Chicago, Wilmington & Franklin Coal Co., 47 N.E.2d 96 (Ill. 1943); <i>see also</i> Miller v. Ridgley, 117 N.E.2d 759 (Ill. 1954).	Right to use of the surface to enjoy mineral estate, <i>see</i> Jilek v. Chicago, Wilmington & Franklin Coal Co., 47 N.E.2d 96 (Ill. 1943); <i>see also</i> Miller v. Ridgley, 117 N.E.2d 759 (Ill. 1954).	765 ILL. COMP. STAT. ANN. 530/1 (West 2020).
KY	Akers v. Baldwin, 736 S.W.2d 294 (Ky. 1987).	Akers v. Baldwin, 736 S.W.2d 294 (Ky. 1987).	KY. REV. STAT. ANN. § 353.595 (West 2020).
MT	Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc., 259 P.3d 766 (Mont. 2011).	—	MONT. CODE ANN. § 82-10-501 <i>et seq</i> (West 2020).
NM	McNeill v. Burlington Res. Oil & Gas Co., 82 P.3d 21 (N.M. 2008).	Reasonable Use Rule, Amoco Production Co. v. Carter Farms Co., 703 P.2d 894, 897-98 (N.M. 1985) (abrogated by McNeill v. Burlington Res., 182 P.3d 121 (N.M. 2008)).	N.M. STAT ANN. § 70-12-1 <i>et seq.</i> (West 2020).
ND	Hunt Oil Co. v. Kerbaugh, 283 N.W.2d 131 (N.D. 1979).	Accommodation Doctrine, Hunt Oil Co. v. Kerbaugh, 283 N.W.2d 131 (N.D. 1979).	Surface Owner Protection Act, N.D. CENT. CODE ANN. §§ 38-18-01 to 08 (West 2020); Oil and Gas Production Damage Compensation Act, N.D. CENT. CODE ANN. §§ 38-11.1-01 to 10 (West 2020).
OH	<i>See</i> Chesapeake Exploration, L.L.C. v. Buell, 45 N.E.3d 185 (Ohio 2015).	Surface Destruction Doctrine, Chesapeake Exploration, L.L.C. v. Buell, 45 N.E.3d 185 (Ohio 2015).	OHIO REV. CODE ANN. §§ 1509.072, .32, .33 (West 2020).
PA	Belden & Blake Corp. v. DCNR, 969 A.2d 528 (Pa. 2009).	Reasonable Use Rule, Oberly v. H.C. Frick Coke Co., 104 A. 864 (Pa. 1918).	—
TN	McBurney v. Glenmary Coal & Coke Co., 118 S.W. 694 (Tenn. 1909).	Limited to ownership and extraction alone, McBurney v. Glenmary Coal & Coke Co., 118 S.W. 694 (Tenn 1909).	Oil and Gas Surface Owners Compensation Act of 1984, TENN. CODE ANN. §§ 60-1-601 to -608 (West 2020).
TX	Getty Oil Co. v. Jones, 470 S.W.2d 618 (Tex. 1971).	Accommodation Doctrine. Getty Oil Co. v. Jones, 470 S.W.2d 618 (Tex. 1971).	—
WV	Squires v. Lafferty, 212 S.W. 90 (W. Va. 1924).	Reasonable Use Rule, Squires v. Lafferty, 212 S.W. 90 (W. Va. 1924).	Oil and Gas Production Damage Compensation Act, W. VA. CODE ANN. §§ 22-7-1 to -8 (West 2020)
WY	Mingo Oil Producers v. Kamp Cattle Co., 776 P.2d 736 (Wyo. 1989).	—	Wyoming Split Estate Act, WYO. STAT. ANN. § 30-5-401 to 410 (West 2020).

Multiple Mineral Conflicts

Only two states, North Dakota and Wyoming, have an established process or mechanism in place to address disputes between multiple mineral estates and/or developers. Conflicts between multiple mineral developers may arise between the owners of different minerals, for instance coal and oil and gas or coal and hard rock mining. In North Dakota, the Industrial Commission is tasked with resolving conflicts between mineral estates to prevent waste and to protect correlative rights. In Wyoming, courts have adapted the local accommodation doctrine to resolve such disputes. The remaining states only regulate some aspects of certain conflicts, if they regulate multiple mineral conflicts at all. It is difficult to predict how any one state will handle such conflicts in the absence of any judicial or legislative directive, much less anticipate any trends among the states.

Multiple Mineral Conflict Resolution	
CO	No statutory or judicial priority between mineral estates or resolution mechanism. However, counties are required to adopt mineral extraction plans for effective multiple sequential use. COLO. REV. STAT. ANN. § 31-1-304 (West 2020).
IL	No statutory or judicial priority between mineral estates or resolution mechanism.
KY	No statutory or judicial priority between mineral estates or resolution mechanism.
MT	Earlier-in-time hard-rock mining claims on public land take precedence over later-in-time claims. MONT. CODE ANN. § 82-2-110 (West 2020).
NM	On state lands, the commissioner may extend or suspend oil and gas operations to prevent waste of all substances. N.M. STAT. ANN. § 19-0-8 (West 2020). Oil and gas operations are prohibited in areas with commercial deposits of potash. N.M. STAT. ANN. § 70-2-3 (West 2020).
ND	The North Dakota Industrial Commission is authorized to regulate conflicts among multiple mineral estates. N.D. CENT. CODE ANN. § 38-15-03 (West 2020).
OH	No statutory or judicial priority between mineral estates or resolution mechanism.
PA	No statutory or judicial priority between mineral estates or resolution mechanism.
TN	No statutory or judicial priority between mineral estates or resolution mechanism.
TX	No statutory or judicial priority between mineral estates or resolution mechanism.
WV	No statutory or judicial priority between mineral estates or resolution mechanism.
WY	Conflicts are resolved according to the accommodation doctrine, giving priority to the first user. Conflicts regarding ownership of various mineral estate attributes are resolved by interpreting the intent of the parties. <i>See Newman v. RAG Wyo. Land Co.</i> , 53 P.3d 540 (Wyo. 2002); <i>BTU Western Res., Inc. v. Berenergy Corp.</i> , 442 P.3d 50 (Wyo. 2019); WYO. RULES & RES. BD. LAND COMM'RS ch. 18, § 15 and ch. 19, § 18 (2020).

Pore Space Ownership

The majority of states have vested ownership of pore space in the surface owner, but Colorado, Illinois, Ohio, Tennessee, and Pennsylvania have not directly addressed ownership of pore space. Except Colorado, even these states recognize the right of a surface owner to bring a claim for subsurface trespass in the pore space. In Kentucky, pore space ownership is only settled within the context of CO₂ storage. With the notable exceptions of West Virginia and North Dakota, all states that have vested pore space ownership in the surface owner recognize that a surface owner has standing to bring a subsurface trespass claim. West Virginia courts have not yet had occasion to address subsurface trespass claims. In contrast, North Dakota legislatively removed previously existing statutory and judicial claims a surface owner could bring relative to unauthorized use of pore space. This statutory action represents a departure from the majority of states' demonstrated preference to protect surface owner property rights in the subsurface.

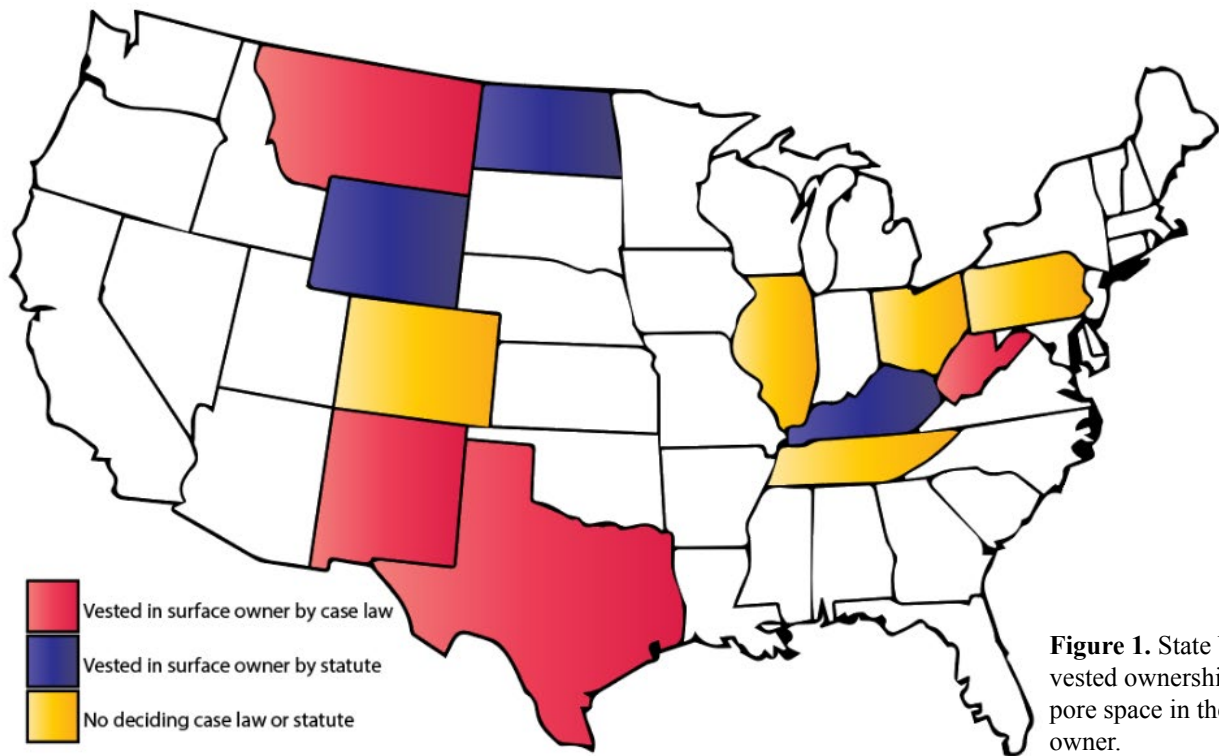


Figure 1. State by state vested ownership of pore space in the surface owner.

Pore Space Ownership	
CO	No deciding case law or statute.
IL	No deciding case law or statute, <i>but see</i> IL HB4370 “Carbon Dioxide Storage.”
KY	KY. REV. STAT. ANN. § 353.800.
MT	Burlington Res. Oil & Gas Co., LP v. Lan & Sons, Inc., 259 P.3d 766 (Mont. 2011).
NM	Jones-Noland Drilling Co. v. Bixby, 282 P. 382 (N.M. 1929).
ND	N.D. CENT. CODE ANN. § 47-31-03.
OH	No deciding case law or statute.
PA	No deciding case law or statute.
TN	No deciding case law or statute.
TX	Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39 (Tex. 2017).
WV	Tate v. United Fuel Gas, 71 S.E.2d 65 (W. Va. 1952).
WY	WYO. STAT. ANN. § 34-1-152.

Subsurface Trespass

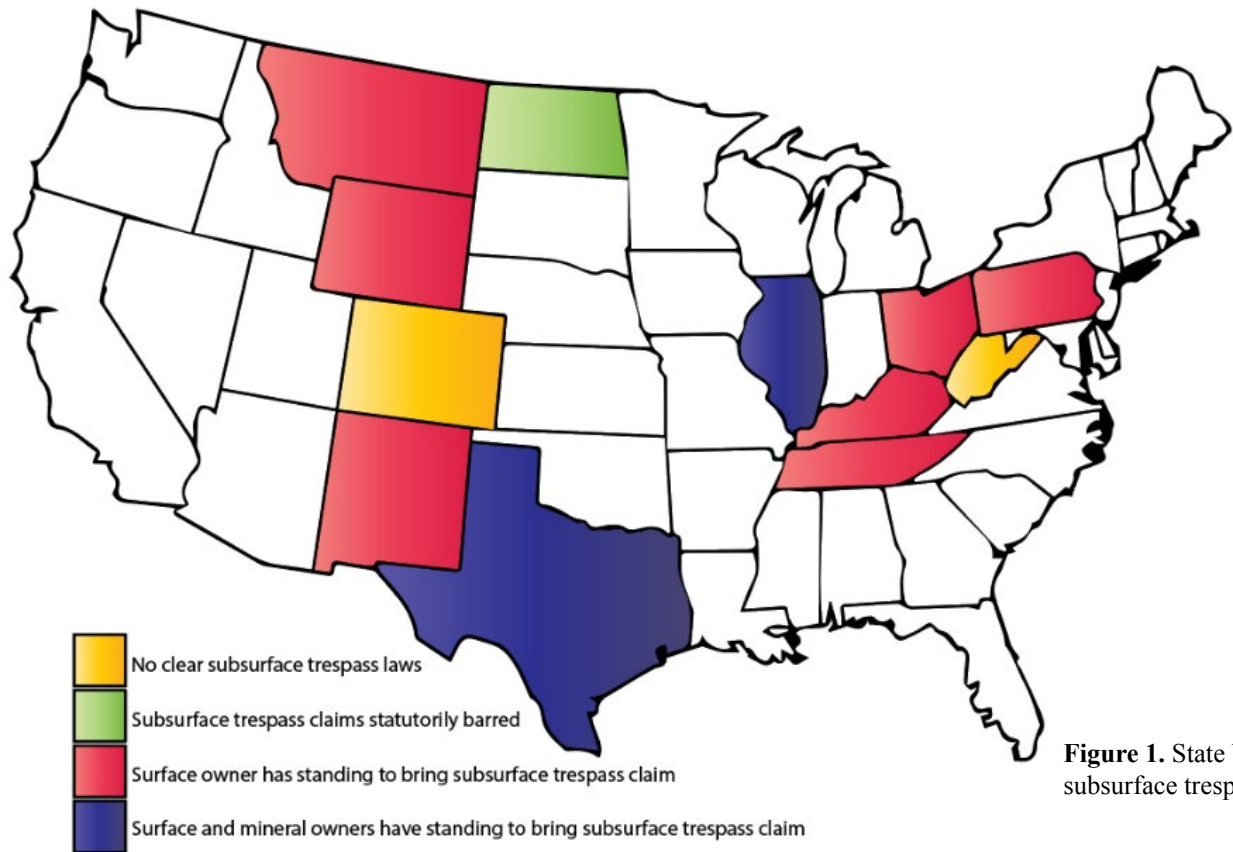


Figure 1. State by state subsurface trespass laws.

Subsurface Trespass		
	Who Has Standing	Requirement for Subsurface Trespass Claim
CO	No clear subsurface trespass laws.	—
IL	Both surface and mineral owners or lessees may bring subsurface trespass claims. <i>See City of Chicago v. Troy Laundry Machinery Co.</i> , 162 F. 678 (7 th Cir. 1908); <i>Texas Co. v. Hollingsworth</i> , 604 Ill. App. 607 (Ill. App. Ct. 1940).	A surface owner must prove more than mere migration of substances, it must also prove “negligent or intentional conduct” which results in an “intrusion on the plaintiff’s interest in exclusive possession of land.” <i>Vill. of DePue</i> , <i>Illinois v. Viacom Int’l, Inc.</i> , 632 F. Supp. 2d 854, 865 (C.D. Ill. 2009) (citing <i>Porter v. Urbana–Champaign Sanitary Dist.</i> , 604 N.E.2d 393, 397 (Ill. App. Ct. 1992).
KY	Surface owner may bring subsurface trespass claim. <i>See Harrod Concrete & Stone v. Crutcher</i> , 458 S.W.3d 290 (Ky. 2015).	The surface owner must demonstrate a loss in fair market value of their property, but the application of this requirement has not yet been used in a subsurface migration context. <i>See Harrod Concrete & Stone v. Crutcher</i> , 458 S.W.3d 290 (Ky. 2015).
MT	Surface owner may bring subsurface trespass claim. <i>See Burlington Res. Oil & Gas Co., LP v. Lang & Sons</i> , 259 P.3d 766 (Mont. 2011).	To prevail, surface owner must demonstrate a loss in agricultural production or income, or devaluation of the surface or improvements. <i>See Burlington Res. Oil & Gas Co., LP v. Lang & Sons</i> , 259 P.3d 766 (Mont. 2011).

NM	Surface owner may bring subsurface trespass claim. <i>See Snyder Ranches, Inc. v. Oil Conservation Comm'n of State of N.M.</i> , 798 P.2d 587 (N.M. 1990); <i>Hartman v. Texaco Inc.</i> , 937 P.2d 979 (N.M. Ct. App. 1997).	A subsurface trespass claim requires proof of actual invasion. <i>Schwartzman, Inc. v. Atchison, Topeka & Santa Fe Ry. Co.</i> , 857 F. Supp. 838 (D.N.M. 1994).
ND	Surface owners have no statutory or common law claims for unauthorized use of pore space. N.D. CENT. CODE ANN. §§ 38-08-25, 38-11.1-03, 40-31-09 (West 2020).	—
OH	Surface owner may bring subsurface trespass claim. <i>See Chance v. BP Chemicals, Inc.</i> , 670 N.E.2d 985 (Ohio 1996).	To prevail, a surface owner cannot merely show that a trespass has occurred but must also show that the trespass actually interferes with the “reasonable and foreseeable use of the subsurface.” <i>Chance v. BP Chemicals, Inc.</i> , 670 N.E.2d 985, 992 (Ohio 1996).
PA	Fee owner has standing to bring subsurface trespass claim. <i>See Briggs v. Southwestern Energy Production Co.</i> , 224 A.3d 334 (Pa. 2020).	A subsurface trespass claim must allege a physical intrusion, and not merely an inference based on generalized characteristics of a particular drilling method. <i>Briggs v. Southwestern Energy Production Co.</i> , 224 A.3d 334, 352 (Pa. 2020).
TN	Surface owner may bring subsurface trespass claim. <i>See Coal Creek Min. & Mfg. Co. v. Mose</i> , 83 Tenn. 300 (Tenn. 1885).	No articulated requirements for a subsurface trespass claim.
TX	Both surface and mineral owners or lessees may bring subsurface trespass claims. <i>See Coastal Oil & Gas Corp. v. Garza Energy Tr.</i> , 268 S.W.3d 1 (Tex. 2008); <i>Lightning Oil Co. v. Anadarko E&P Onshore, LLC</i> , 520 S.W.3d 39 (Tex. 2017).	A subsurface trespass claim requires a demonstration of actual injury; simple drainage of oil and gas from fracturing does not constitute actionable injury. <i>Coastal Oil & Gas Corp. v. Garza Energy Tr.</i> , 268 S.W.3d 1 (Tex. 2008).
WV	Subsurface trespass has been alleged in several cases, but no court has definitively ruled on the issue. <i>See, e.g. EQT Production Co. v. Crowder</i> , 828 S.E.2d 800 (W.V. 2019).	No articulated requirements for subsurface trespass claim.
WY	Mineral operator may bring subsurface trespass claim. <i>See ANR Prod. Co. v. Kerr-McGee Corp.</i> , 893 P.2d 698 (Wyo. 1995).	To prevail, the party claiming subsurface trespass must demonstrate injury. <i>See ANR Prod. Co. v. Kerr-McGee Corp.</i> , 893 P.2d 698 (Wyo. 1995).

Local Regulation of Oil and Gas Development

Half of the states examined in this report have statewide oil and gas laws that expressly or impliedly preempt local regulation of oil and gas development. All of these states, however, allow local governments to exercise some regulatory authority through zoning, or zoning-type, ordinances. Montana is unique in that its legislature created a loophole to state preemption by allowing property owners to band together to form zoning districts with the authority to potentially prevent unwanted mineral development. Six states have not expressly preempted local regulation, but even these states do not allow local governments to regulate all aspects of oil and gas development. Some rules, like those on unitization, remain in the exclusive domain of the state government. Colorado, which recently adopted the most permissive conservation act with respect to local regulation, allows city and county governments to adopt more stringent regulations than the Colorado Oil and Gas Conservation Commission, but only with respect to surface use and operation siting for the purposes of protecting public health, safety, welfare, and the environment.

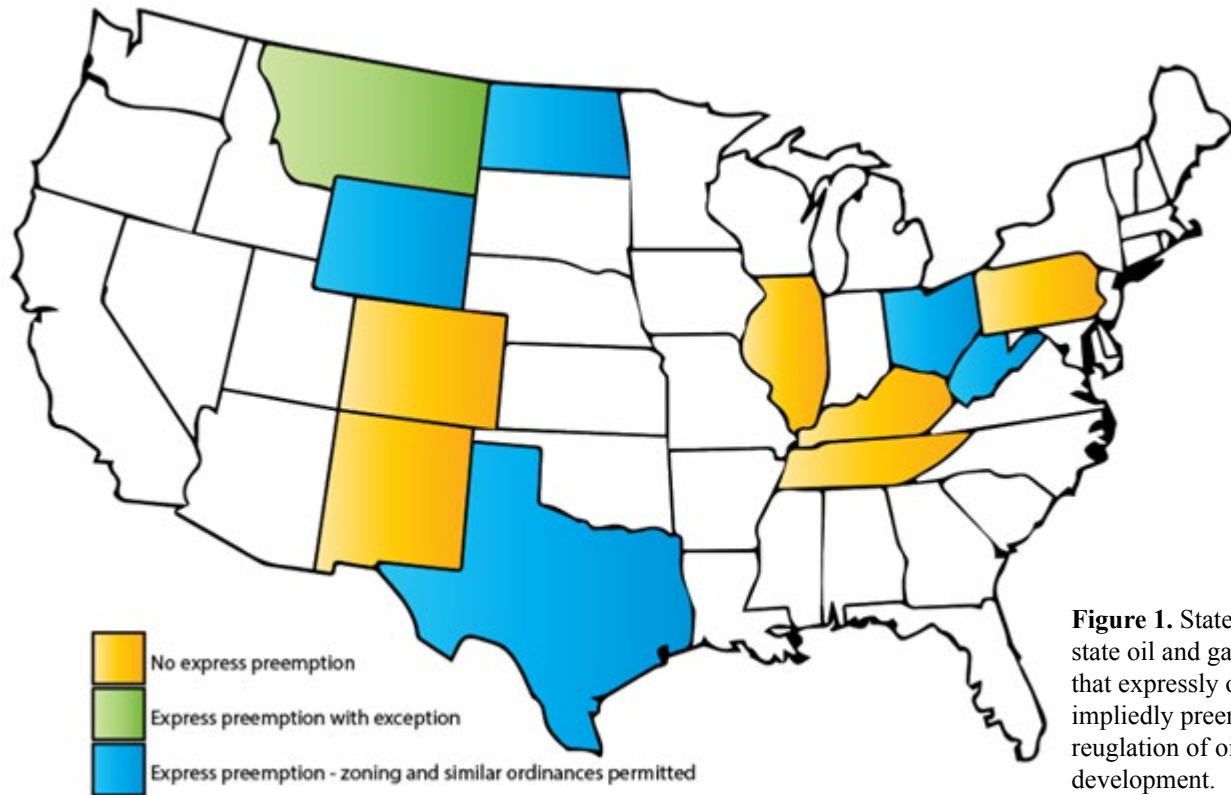


Figure 1. State by state oil and gas laws that expressly or impliedly preempt local regulation of oil and gas development.

Local Regulation		
	Preemption	Local Governments May Regulate:
CO	Statutes prohibit preemption of local regulation regarding land and surface use. COLO. REV. STAT. ANN. § 29-20-104; 34-60-131.	Local governments may impose more protective or stricter regulations, regulate land and surface use, and regulate the location and siting of oil and gas facilities for the purposes of protecting public health, safety, welfare and the environment. COLO. REV. STAT. ANN. § 29-20-104; 34-60-116; 34-60-131.
IL	No preemption. 65 ILL. COMP. STAT. ANN. 5/1-56-1; 225 ILL. COMP. STAT. ANN. 725-13.	Oil and Gas Commission will not issue a permit without the consent of the local government, 225 ILL. COMP. STAT. ANN. 725-13; <i>see also</i> Tri-Power Res., Inc. v. City of Carlyle, 967 N.E.2d 811 (Ill. App. Ct. 5 th Dist. 2012).

KY	No express or implied preemption. KY. REV. STAT. ANN. § 353.500; <i>Blancett v. Montgomery</i> , 398 S.W.2d 877 (Ky. 1996).	Municipalities retain police power to regulate oil and gas operations. <i>Blancett v. Montgomery</i> , 398 S.W.2d 877 (Ky. 1966).
MT	Some local regulation preempted. MONT. CODE ANN. § 76-1-13; 76-2-209.	Real property owners may create planning and zoning districts which may ban mineral estate development. MONT. CODE ANN. § 76-2-101 and 109.
NM	No express or implied preemption. <i>See SWEPI, LP v. Mora Cty.</i> , N.M. 81 F.Supp.3d 1075 (D.N.M. 2015).	Counties have concurrent jurisdiction with state over oil and gas operations and may enact more and stricter regulations than the state but may not completely ban activities permitted by the state. <i>SWEPI, LP v. Mora Cty. N.M.</i> , 81 F.Supp.3d 1075 (D.N.M. 2015).
ND	Local regulation is largely preempted. <i>Envtl. Driven Sols., LLC v. Dunn Cty.</i> , 890 N.W.2d 841 (N.D. 2019).	Local governments may regulate aspects expressly delineated by legislature. <i>Sauby v. City of Fargo</i> , 747 N.W.2d 65 (N.D. 2008).
OH	Local regulation is largely preempted. OHIO REV. CODE ANN. § 4905.96; State ex rel. <i>Morrison v. Beck Energy Corp.</i> , 37 N.E.3d 128 (Ohio 2015).	Local governments may not exercise police power over oil and gas operations, State ex rel. <i>Morrison v. Beck Energy Corp.</i> , 37 N.E.3d 128 (Ohio 2015), but may enforce certain zoning ordinances. State ex rel. <i>Kostoff v. Beck Energy Corp.</i> , 34 N.E.3d 775 (Ohio Ct. App., 2019).
PA	Local regulation is largely preempted.	Local governments may impose zoning ordinances. 58 Pa. C.S. §§ 2301 to 3504; <i>Huntley & Huntley, Inc. v. Borough Council of Borough of Oakmont</i> , 600 Pa. 207 (2009), charge fees, 58 Pa. Stat. and Cons. Stat. Ann. § 2302 (West); and enforce setback rules, <i>Frederick v. Allegheny Twp. Zoning Hearing Bd.</i> , 196 A.3d 677 (Pa. Commw. Ct. 2018).
TN	No express or implied preemption.	Local regulation may impose spacing rules in conformance with state regulations. Tenn. Comp. R. & Regs. 0400-52-04.01.
TX	Local regulation is largely preempted. TEX. NAT. RES. CODE ANN. § 81.0523.	Local governments may regulate aboveground activities. TEX. NAT. RES. CODE ANN. § 81.0523
WV	Local regulation is largely preempted, <i>Northeast Natural Energy, LLC v. The City of Morgantown</i> , No. 11-C-411, 2011 WL 3584376 (W. Va. Cir. Ct. 2011).	Local governments may impose and enforce zoning ordinances. W. VA. CODE ANN. § 8A-7-3.
WY	Local regulation is largely preempted. WYO. STAT. ANN. § 18-5-201.	Local governments may impose zoning ordinances. WYO. STAT. ANN. § 18-5-201.

Oil and Gas Unitization Regulatory Framework

All states examined in this report allow oil and gas reservoirs to be unitized for economic development. With the exception of Texas, all states have authorized their oil and gas conservation commissions to order or force unitization, and seven states, including Texas, allow property owners to voluntarily unitize their interests. Colorado recently updated its oil and gas regulations to allow “comprehensive drilling units,” which allow an oil and gas operator to voluntarily create larger units, upon approval of the COGCC, in order to produce greater quantities of oil and gas while minimizing environmental impacts.

The majority of states have not, however, addressed pore space unitization for purposes of CO₂ sequestration. Only Kentucky, Montana, North Dakota, and Wyoming have statutes in place permitting pore space unitization. Where state legislatures have not enacted rules for forced unitization, a storage operator will need to reach voluntary agreements with each surface owner whose pore space is part of the storage reservoir. In states like Colorado, where pore space ownership has not been vested in the surface owner as a matter of law, this may be more difficult than in states where pore space ownership is clearly delineated.

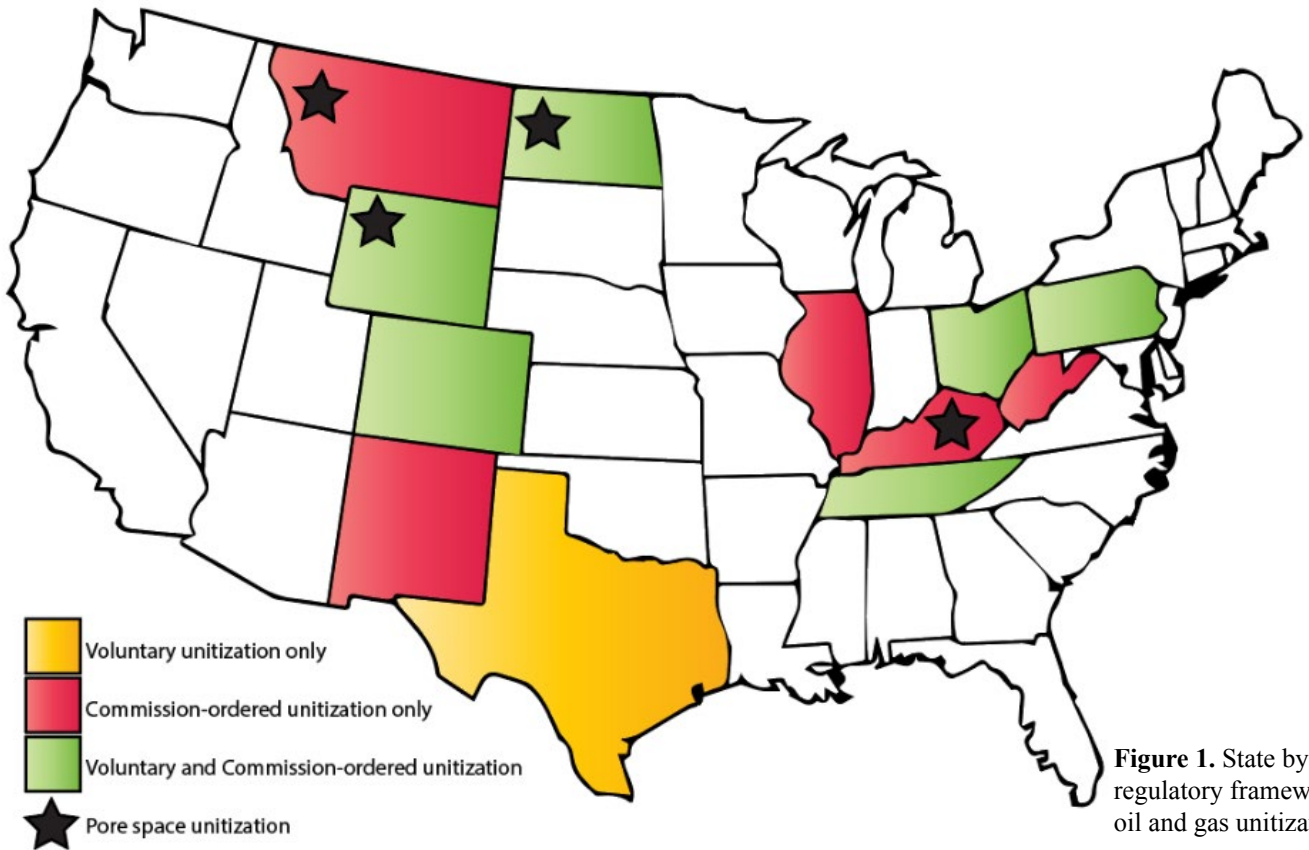


Figure 1. State by state regulatory framework for oil and gas unitization.

Unitization				
	Voluntary Unitization	Ordered Unitization	Consent of Owners Required	Unitization of Pore Space
CO	COLO. REV. STAT. ANN. § 34-60-118 (West 2020). Comprehensive Drilling Plans are permitted under new regulations, 2 Colo. Code Regs. § 404-1:216.	COLO. REV. STAT. ANN. § 34-60-118 (West 2020).	80% owner consent required. Colo. Rev. Stat. Ann. § 34-60-118 (West 2020).	—

IL	—	225 ILL. COMP. STAT. ANN. 725/23.3 (West 2013).	Consent of owners who will pay at least 51% of costs. 225 ILL. COMP. STAT. ANN. 725/23.3 (West 2013).	—
KY	—	KY. REV. STAT. ANN. § 353.652.	Consent of owners who will share 75% of costs and production. KY. REV. STAT. ANN. § 353.652	KY. REV. STAT. ANN. §§ 353.806 to 808 (West 2011).
MT	—	MONT. CODE ANN. § 82-1-205 (West 2019).	60% owner consent required. MONT. CODE ANN. § 82-1-204 (West 2019).	MONT. CODE ANN. § 82-11-183 (West 2019).
NM	—	Statutory Unitization Act, N.M. STAT. ANN. § 70-7- to 21 (West 2020).	Consent of owners who will pay 75% of costs.	—
ND	N.D. CENT. CODE ANN. § 38-08-09 (West 2020).	N.D. CENT. CODE ANN. § 38-08-09.5 (West 2020).	Consent of owners who will pay 55% of costs and 55% of royalty interest owners. N.D. CENT. CODE ANN. § 38-08-09.5 (West 2020).	N.D. CENT. CODE ANN. § 38-22-17.
OH	OHIO REV. CODE ANN. § 1509 (West 2011).	OHIO REV. CODE ANN. § 1509.27 (West 2015).	Consent of 65% of acreage owners. OHIO REV. CODE ANN. § 1809.28 (West 2019).	—
PA	58 PA. STAT. AND CONS. STAT. ANN. § 408.	58 PA. STAT. AND CONS. STAT ANN. § 408.	—	—
TN	TENN. CODE ANN. § 60-1-202 (West 2013)	TENN. CODE ANN. § 60-1-202 (West 2013).	Consent of 50% of acreage owners. TENN. CODE ANN. § 60—202 (West 2013).	—
TX	TEX. NAT. RES. CODE ANN. § 101.001 to 052 (West 2019).	—	—	—
WV	—	W. VA. CODE ANN. § 22C-9-8.	Consent of 75% of royalty owners and operators. W. VA. CODE ANN. § 22C-9-8.	—
WY	WYO. STAT. ANN. § 30-5-110 (West 2020).	WYO. STAT. ANN. § 30-5-110 (West 2020).	Consent of 80% of royalty and working interest owners. WYO. STAT. ANN. § 30-5-110 (West 2020).	WYO. STAT. ANN. §§ 35-11-313 to 318 (2020).

Geologic CO₂ Storage Regulatory Framework

Most states covered by this report regulate some aspect of CO₂ underground storage. Colorado, New Mexico, Ohio, Pennsylvania, and Tennessee currently have no regulatory framework in place for geologic CO₂ storage. Additionally, North Dakota and Wyoming are the only states in the U.S. with primacy over Class VI injection wells. Similarly, the majority of states have not directly addressed liability for injected CO₂ as part of geologic storage projects. Only North Dakota and Kentucky have current statutory programs for liability transfer to the state, whereas Montana has a contingency regulation which could permit liability transfer. Although Wyoming has no statute regarding liability transfer, it specifies that liability for injected CO₂ remains with the injector and its laws establish a fund for state monitoring, reporting, and verification. Where there is no specific statute, regulation, or case law regarding liability, analogs to natural gas storage projects and to oil and gas injection operations indicate the liability may remain with the injector. For states adopting the discovery rule for statutes of limitation, this could extend liability for a potentially indefinite period. Inconsistency in state liability transfer programs and the absence of a federal program for liability transfer may be an impediment to transboundary or regional geologic storage projects or project that involve a combination of state, federal, private, and tribal lands.

Only three states, Kentucky, Montana, and North Dakota, provide a mechanism for ownership of injected CO₂ to be transferred to the state, although Montana does so only in contingency statutes. Of these three, both Montana and North Dakota require “certification” of injected CO₂ before ownership can be transferred. Certification in these states simply verifies that the CO₂ is stable, or bonded with molecules in the pore space reservoir, and unlikely to migrate out of the storage reservoir into other geologic formations. Receipt of certification allows the storage operator to decrease or cease required monitoring activities at the storage reservoir for CO₂ escape. In the absence of certification and ownership transfer mechanisms, storage operators, or their successors, will maintain ownership and liability for injected CO₂ in perpetuity.

Two states mentioned in this report certify CO₂ injected and stored for purposes not related to liability transfer regimes. Wyoming’s certification process only certifies CO₂ stored incidental to CO₂-EOR projects, whereas in Texas, certification is only given to qualifying CO₂-EOR wells to verify the applicability of a severance tax rate that is used in conjunction with anthropogenic CO₂.

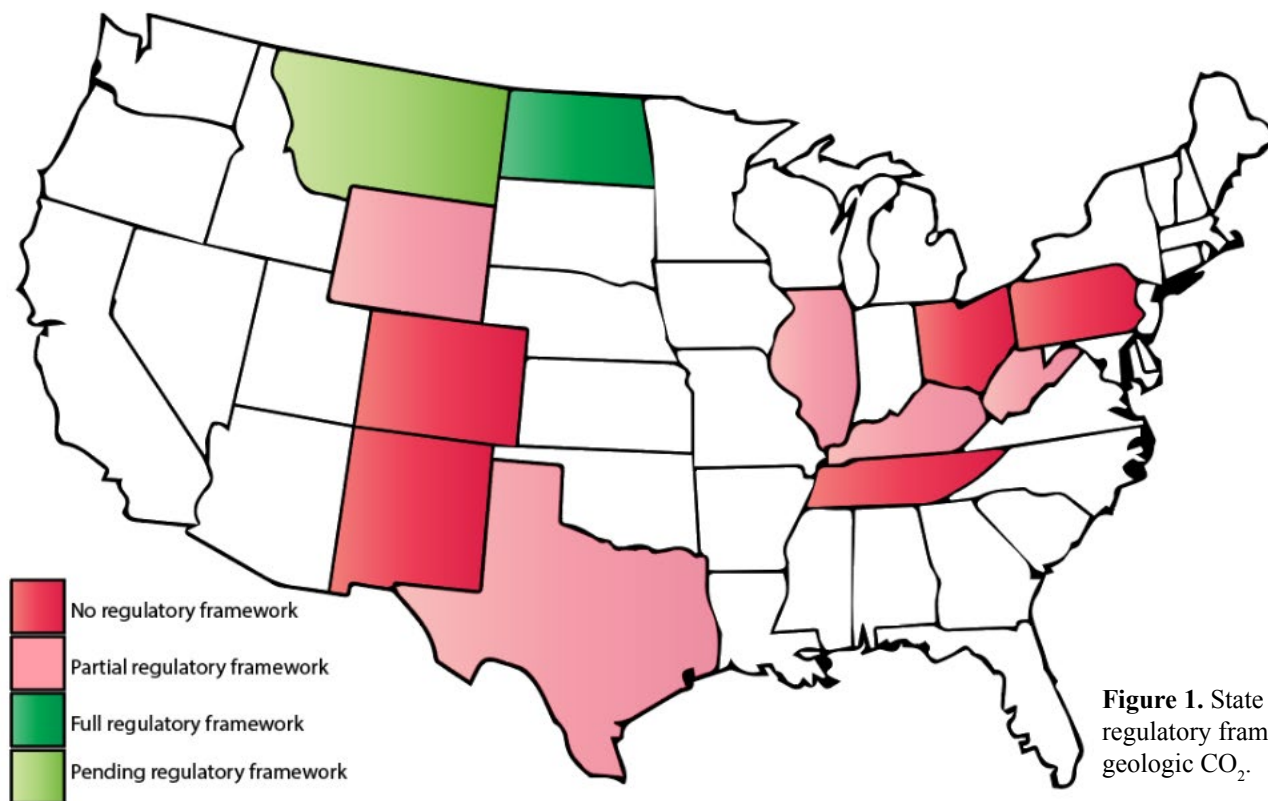


Figure 1. State by state regulatory framework for geologic CO₂.

Geologic CO ₂ Storage Regulatory Framework						
	Regulated by oil and gas conservation commission	Ownership and liability for injected CO ₂	Ownership of injected CO ₂ transferred to the state	Pore space operated as a unit of CO ₂ geologic storage	Bonding Requirements for CO ₂ Drilling	Certification regulations
CO	—	—	—	—	—	—
IL	Illinois Environmental Protection Agency. 35 ILL. ADM. CODE 730/182.	20 ILL. COMP. STAT. ANN. 1105/20; <i>see also</i> 35 Ill. Adm. Code 730/193	—	—	35 ILL. ADM. CODE 730/185.	—
KY	KY. REV. STAT. ANN. § 353.804.	KY. REV. STAT. ANN. § 353.810.	KY. REV. STAT. ANN. § 353.810.	KY. REV. STAT. ANN. § 353.806.	—	—
MT	MONT. CODE ANN. § 82-11-111.	MONT. CODE ANN. § 82-11-182.	MONT. CODE ANN. § 82-11-183.	—	MONT. CODE ANN. § 82-11-123 and 137.	MONT. CODE ANN. § 82-11-183 (West 2019)
NM	—	—	—	—	—	—
ND	N.D. CENT. CODE ANN. § 38-22-03.	N.D. CENT. CODE ANN. § 38-22-16.	N.D. CENT. CODE ANN. § 38-22-17.	N.D. CENT. CODE ANN. § 38-22-08 to 10.	N.D. CENT. CODE ANN. § 38-22-14 and 15.	N.D. CENT. CODE ANN. § 38-22-17.
OH	—	—	—	—	—	—
PA	—	—	—	—	—	—
TN	—	—	—	—	—	—
TX	16 TEX. ADMIN. CODE § 5.101.	—	—	—	16 TEX. ADMIN. CODE § 5.205.	Certification required for eligibility for CO ₂ -EOR tax rate reduction. 16 TEX. ADMIN. CODE § 3.50.
WV	West Virginia Department of Environmental Protection W. VA. CODE ANN. § 22-11A-3.	—	—	—	W. VA. CODE ANN. § 22-11A-5.	—
WY	WYO. STAT. ANN. § 35-11-313 to 318.	WYO. STAT. ANN. § 34-1-153.	—	WYO. STAT. ANN. § 35-11-313 to 316.	—	Certification of CO ₂ incidental to CO ₂ -EOR. WYO. STAT. ANN. § 30-5-502.

Induced Seismicity Regulation

Most states regulate induced seismicity to some extent: of the states studied, only Kentucky, Tennessee, West Virginia, and Wyoming have no rules or policy relative to induced seismicity. Texas, North Dakota, and Illinois all directly regulate induced seismicity. Texas and North Dakota (as well as Montana through its contingency statutes) are proactive in their regulatory approach, and require injection operators to take, or refrain from, specific actions to reduce earthquake potential. Conversely, Illinois regulations are reactionary, and require operators and the state Geologic Survey to monitor an area only after seismic activity has occurred. Other states, including Colorado, New Mexico, Ohio, Pennsylvania, and North Dakota (in addition to its regulations), have policies in place requiring CO₂-EOR and geologic storage operators to prepare reports on the potential for induced seismicity with regard to CO₂ injection. Most state regulations or policy are directed at either Class II or Class VI wells, but most aspects are equally applicable to the other well type. For example, reports on the likelihood of induced seismicity can be prepared and analyzed for both Class II and VI wells.

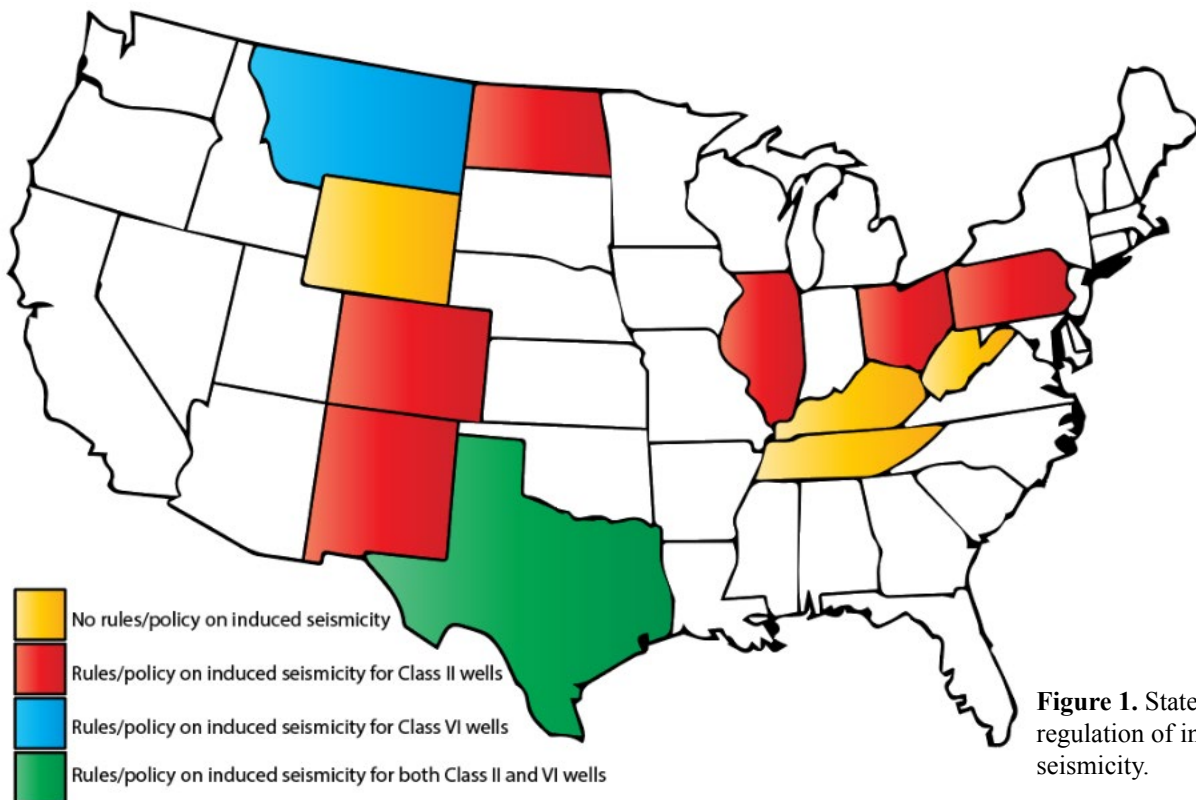


Figure 1. State by state regulation of induced seismicity.

Induced Seismicity Regulation	
CO	COGCC policy mandates that injectors in Class II wells keep pressure and injection level below standards established for each well. COGCC monitors basement rocks and sealing zones to reduce induced seismicity potential. <i>See</i> Engineering Unit, Colo. Oil & Gas Conservation Comm'n Seismicity Review for Class II Underground Injection Control Wells (2011).
IL	In the event a Class II well induces seismic activity, the operator must develop a monitoring plan in conjunction with the Illinois State Geologic Survey and Department of Natural Resources. ILL. ADMIN. CODE tit. 62, § 240.796.
KY	Operators must regulate injection pressure to avoid adding stress to extant fractures or creating new ones. 805 KY. ADMIN. REGS. 1:110 § 3 (2020)
MT	Contingency statutes require MBOGC to monitor and regulate Class VI wells for CO ₂ escape and induced seismicity. MONT. CODE ANN. § 82-11-123 (effective on the date that the board or oil and gas conservation is granted primacy to administer activities at CO ₂ sequestration wells by the EPA as established in 2009 Mont. Laws ch. 474, § 7).

NM	NMOCD policy prohibits injection below certain geologic sequences and formations, and coordinates with the N.M. Bureau of Geology and Mineral Resources to monitor seismic activity relative to Class II injection wells. State of New Mexico Class II UIC Program Peer Review, Ground Water Protection Council (2020).
ND	To minimize induced seismicity, NDIC rules prohibits Class II injection wells be located in open faults or fractures and NDIC policy generally requires that disposal injection wells be located a half-mile below underground water sources and two miles above basement rock formations. N.D. ADMIN. CODE 43-02-05-05; North Dakota State Government, Underground Injection Control Program Frequently Asked Questions.
OH	The Ohio Environmental Protection Agency will deny an injection permit if the proposed injections are likely to induce seismicity. OHIO REV. CODE ANN. § 6111.044 (West 2016).
PA	Application for Class II well operations must include a report on the potential for induced seismicity. Pennsylvania Dept of Envntl. Protection, Injection Wells for Enhanced Recovery Disposal.
TN	No legislative or judicial rules or regulations on induced seismicity.
TX	All disposal well operators must supply RRC with information on potential for induced seismicity. 16 TEX. ADMIN. CODE § 3.9. Storage well operators must do likewise. 16 TEX. ADMIN. CODE § 5.203. The RRC may modify, suspend or terminate a Class II well permit if the well is either likely to or found to be inducing seismicity. 16 TEX. ADMIN. CODE § 3.46(d).
WV	No legislative or judicial rules or regulation on induced seismicity.
WY	No legislative or judicial rules or regulations on induced seismicity.

Eminent Domain Authority for Common Carrier Pipelines

The majority of states recognize the authority of a pipeline operator to carry out eminent domain proceedings. Only a select few of the states covered in this report require the pipeline operator to be a common carrier, whereas most states grant eminent domain authority to Public Utility Commissions (PUCs) and corporations. Most eminent domain statutes fail to consider carbon dioxide pipelines in their regulatory scheme. Illinois, North Dakota, and Kentucky are the only three states covered in this report that have a full CO₂ pipeline regulatory framework. Illinois and North Dakota specifically regulate CO₂ pipeline safety and siting and grant CO₂ common carrier pipelines eminent domain authority, whereas Kentucky does not require the CO₂ pipeline to be a common carrier. Tennessee does not have a full CO₂ pipeline regulatory framework; however, the Attorney General of Tennessee opined that a pipeline corporation has the right to condemn land for the transportation and distribution of carbon dioxide.

EMINENT DOMAIN AUTHORITY				
State	Pipeline Siting Authority	Common Carriers Authorized to Exercise Eminent Domain	CO ₂ Pipelines Authorized to Exercise Eminent Domain	Common Carrier Requirement for CO ₂ Pipelines
CO	Colorado Public Utilities Commission	Possibly [<i>See</i> COLO. REV. STAT. ANN. § 38-4-102; <i>but see also</i> Larson v. Sinclair Transportation Co., 284 P.3d 42, 45 (Colo. 2012), <i>rehearing denied</i> (2012)]	Possibly with common carrier status [<i>See</i> COLO. REV. STAT. ANN. § 38-4-102; <i>but see also</i> Larson v. Sinclair Transportation Co., 284 P.3d 42, 45 (Colo. 2012), <i>rehearing denied</i> (2012)]	No
IL	Illinois Commerce Commission	Enbridge Energy, L.L.C. v. Keurth, 99 N.E.3d 210 (Ill. App. 2018). <i>See also</i> 735 ILL. COMP. STAT. ANN. 30/5-5-5(c) and 220 ILL. COMP. STAT. ANN. 5/9-509	220 ILL. COMP. STAT. ANN. 75/20.	220 ILL. COMP. STAT. ANN. 75/10.
KY	Kentucky Public Service Commission	KY. REV. STAT. ANN. § 416.675	KY. REV. STAT. ANN. § 154.27-100	No
MT	Montana Department of Environmental Quality; Board of Environmental Review	MONT. CODE ANN. § 69-13-103	MONT. CODE ANN. § 69-13-101	MONT. CODE ANN. § 69-13-103
NM	New Mexico Public Safety Commission Pipeline Service Bureau; Oil Conservation Division	N.M. STAT. ANN. § 70-3-5	N.M. STAT. ANN. § 70-3-5	No
ND	North Dakota Public Service Commission	N.D. CENT. CODE ANN. § 49-19-09; N.D. Cent. Code Ann. § 49-19-12	Allowed with common status [N.D. CENT. CODE ANN. § 49-19-09; N.D. CENT. CODE ANN. § 49-19-12]	N.D. CENT. CODE ANN. § 49-19-08

OH	Public Utilities Commission of Ohio	OHIO REV. CODE ANN. § 163.09. <i>See also</i> OHIO REV. CODE ANN. § 1723.01 for what constitutes a common carrier.	Condemnation for CO ₂ is not specifically authorized. Condemnation for gas, petroleum, coal permitted pursuant to OHIO REV. CODE ANN. § 1723.01; natural gas, petroleum, water, or electricity permitted pursuant to OHIO REV. CODE ANN. § 743.39; transporting, selling, or storing gas permitted pursuant to OHIO REV. CODE ANN. § 1571.17	—
PA	Pennsylvania Public Utilities Commission	15 PA. STAT. AND CONS. STAT. ANN. § 1511. Note that only pipelines registered as a public utility corporation, not a common carrier, may exercise eminent domain	Condemnation for CO ₂ is not specifically authorized. Condemnation for the transportation of artificial or natural gas, petroleum permitted pursuant to 15 PA. STAT. AND CONS. STAT. ANN. § 1551(a)(2).	—
TN	Tennessee Regulatory Authority	TENN. CODE ANN. § 29-17-102.	The Attorney General opined that a pipeline corporation has the right to condemn land for the transportation and distribution of carbon dioxide. <i>See</i> Tenn. Op. Att’y Gen. No. 09-165.	—
TX	Texas Railroad Commission	TEX. NAT. RES. CODE § 111.019	Allowed with common carrier status [Tex. Nat. Res. Code § 111.019]	No
WV	Public Service Commission of West Virginia	W. VA. CODE ANN. § 54-1-2. There is no requirement that a pipeline be a common carrier to exercise eminent domain.	Condemnation for CO ₂ is not specifically authorized. Broad condemnation authority permitted pursuant to W. VA. CODE ANN. § 54-1-2.	—
WY	Wyoming Public Service Commission; Wyoming Department of Environmental Quality Industrial Siting Council	<i>See</i> Barlow Ranch Ltd. P’ship v. Greencore Pipeline Co., 301 P.3d 75 (Wyo. 2013); <i>see also</i> WYO. STAT. ANN. §35-11-316	<i>See</i> Barlow Ranch Ltd. P’ship v. Greencore Pipeline Co., 301 P.3d 75 (Wyo. 2013); <i>see also</i> WYO. STAT. ANN. §35-11-316	No

Eminent Domain Authorized for Subsurface Rights

Eminent domain is likely not authorized for Kentucky and Ohio, as both states are silent on it. However, the remainder of states in this report authorize eminent domain authority for subsurface rights in various ways. West Virginia prescribes broad authority for subsurface rights, whereas Pennsylvania only prescribes specific eminent domain authority to a water company.

In the west, both Colorado and Montana have explicitly enumerated underground natural gas storage reservoirs as a public use for eminent domain purposes. Wyoming, on the other hand, has expressly prohibited the use of eminent domain for the purpose of condemning pore space rights. The remainder of the west is much less clear on their position regarding the condemnation of pore space rights, which presents a great deal of uncertainty for any potential operators in these areas.

State	Eminent Domain Authorized for Subsurface Rights
CO	<i>Natural Gas Storage Reservoirs</i> – COLO. REV. STAT. ANN. § 34-64-103 to 106
IL	See 220 ILL. COMP. STAT. ANN. 15 et seq.
KY	KY. REV. STAT. ANN. § 65.478
MT	<i>Natural Gas Storage Reservoirs</i> – MONT. CODE ANN. § 70-30-102(43); see also MONT. CODE ANN. § 70-30-105; MONT. CODE ANN. § 70-30-104(a)(v); see also MONT. CODE ANN. § 82-10-303
NM	—
ND	Pore space for geologic storage has not specifically been recognized as a public use for eminent domain purposes
OH	—
PA	16 PA. STAT. AND CONS. STAT. ANN. § 12907 (when county water supply authorities may acquire subsurface rights through eminent domain)
TN	TENN. CODE. ANN. § 65-28-101; see also TENN. CODE. ANN. § 7-39-101 et seq.
TX	—
WV	W. VA. CODE ANN. § 54-1-2(a)(3)
WY	Condemnation of pore space rights for geologic storage is expressly prohibited – WYO. STAT. ANN. § 35-11-316(j)

WATER

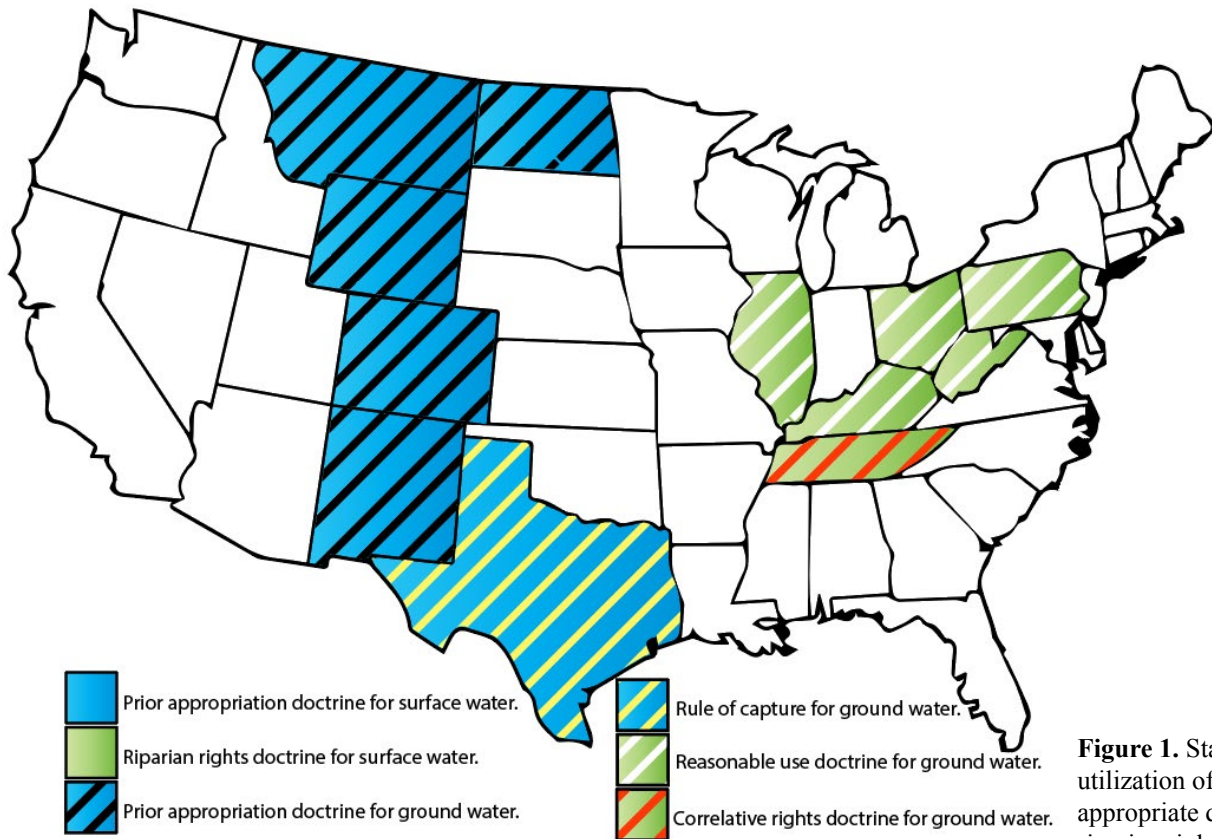


Figure 1. State by state utilization of prior appropriate doctrine and riparian rights.

Surface Water

The doctrinal split between prior appropriation and riparian rights is largely geographical. The doctrine of prior appropriation is utilized west of the 100th Meridian and the riparian doctrine is utilized in some form to the east. All of the riparian states covered implemented the riparian rights doctrine through case law. However, in the west, there is an even split between constitutional and statutory implementation of the prior appropriation doctrine.

SURFACE WATER APPROPRIATION DOCTRINES	
CO	<i>Prior Appropriation</i> – Colo. Const. art. XVI, §6
IL	<i>Riparian Rights</i> – Evans v. Merriweather, 4 Ill. 492 (Ill. 1842)
KY	<i>Riparian Rights</i> – Kraver v. Smith, 164 Ky. 674 (Ky. 1915)
MT	<i>Prior Appropriation</i> – MONT. CODE ANN. § 85-2-401(1)
NM	<i>Prior Appropriation</i> – N.M. Const. art. XVI, § 2
ND	<i>Prior Appropriation</i> – N.D. CENT. CODE § 61-04-06.3
OH	<i>Riparian Rights</i> – Cooper v. Williams, 4 Ohio St. 253 (Ohio 1831); <i>see also</i> Salem Iron Co. v. Hyland, 74 Ohio St. 160 (Ohio 1906)
PA	<i>Riparian Rights</i> – Lord v. Meadville Water Co., 135 Pa. 122 (Pa. 1890); Chambers v. Furry 1 Yeates 167 (Pa. 1792); Alburger v. Philadelphia Elec. Co., 535 A.2d 729 (1988)
TN	<i>Riparian Rights</i> – Webster v. Harris, 69 S.W. 782 (Tenn. 1902)
TX	<i>Prior Appropriation</i> – TEX. WATER CODE ANN. § 11.027
WV	<i>Riparian Rights</i> – Gaston v. Mace, 10 S.E. 60 (W.Va. 1889)
WY	<i>Prior Appropriation</i> – Wyo. Const. art. 8, § 3

Groundwater

The doctrinal split for groundwater is slightly less uniform. A strong preference for prior appropriation still dominates in the west. Texas is the lone western state to deviate from the doctrine of prior appropriation, utilizing the rule of capture. Similarly, in the east, the reasonable use doctrine dominates. Tennessee implements the doctrine of correlative rights for groundwater, but even Tennessee courts fail to recognize the slight differences between that doctrine and the reasonable use rule.

GROUNDWATER APPROPRIATION DOCTRINES	
CO	<i>Prior Appropriation</i> – COLO. REV. STAT. ANN § 37-90-109
IL	<i>Reasonable Use</i> - 525 ILL. COMP. STAT. ANN. 45/3(c)
KY	<i>Reasonable Use</i> - United Fuel Gas Co. v. Sawyers, 259 S.W.2d 466, 468 (Ky. 1953).
MT	<i>Prior Appropriation</i> – MONT. CODE ANN. § 85-2-401(1)
NM	<i>Prior Appropriation</i> – McBee v. Reynolds 399 P.2d 110 (N.M. 1965); <i>see also</i> N.M. Const. art. XVI, § 2
ND	<i>Prior Appropriation</i> – N.D. CENT. CODE ANN. § 61-04-06.3 (West 2020)
OH	<i>Reasonable Use</i> - McNamara v. Rittman, 107 Ohio St. 3d 243, 2005-Ohio-6433, 838 N.E.2d 640 (2005).
PA	<i>Reasonable Use</i> - Rothrauff v. Sinking Spring Water Co., 339 Pa. 129, 14 A.2d 87 (Pa. 1940)
TN	<i>Correlative Rights</i> - Nashville, C. & St. L. Ry. v. Rickert, 19 Tenn. App. 446, 89 S.W.2d 889 (1935)
TX	<i>Rule of Capture</i> – Houston & T.C. Ry. Co. v. East, 81 S.W. 279 (Tex. 1904).
WV	<i>Reasonable Use</i> – Pence v. Carney, 52 S.E. 702 (W.Va. 1905)
WY	<i>Prior Appropriation</i> – Wyo. Const. art. 8, § 1

Produced Water

Considering the arid nature of the west, it is no surprise that the west has a much more detailed framework in place for both the disposal and the appropriation of produced water. Every state in the west has rules governing the disposal of produced water. In addition, every state in the west, save for Texas and North Dakota, provides a framework for the appropriation of produced water for beneficial uses as a way to supplement other sources of water. Texas is no surprise, considering the state adheres to the rule of capture for groundwater withdrawals. In 2019, the North Dakota legislature specifically excluded fossil by-product water from its permit requirements for water impoundments.

Conversely, Illinois is the only eastern state with any type of produced water regulatory framework in place. However, it seems that Illinois is only concerned with the disposal of produced water, to prevent pollution, rather than the appropriations of produced water.

PRODUCED WATER		
State	Disposal or Injection	Appropriations
CO	Non-tributary water produced during oil and gas operations is subject to COGCC regulation if the produced water is disposed of or re-injected for enhanced recovery projects – <i>See</i> 2 CODE OF COLO. REGS. 404-1:901 to 1:911; <i>see also</i> 2 CODE OF COLO. REGS. 404-1:401 to 1:405.	Appropriations of produced water must comply with the state’s Water Rights Act, as well as the Groundwater Act – <i>See</i> Three Bells Ranch Associates v. Cache La Poudre Water Users Ass’n, 758 P.2d 164 (Colo. 1988); <i>see also</i> 2 CODE OF COLO. REGS. 402-17:17.12.

IL	Produced water may only be disposed of by injection into a Class II injection well that is below interface between fresh water and naturally occurring Class IV groundwater or in a permitted enhanced oil recovery operation. See Ill. Admin. Code tit. 62, § 245.940; 225 ILL. COMP. STAT. ANN. 732/1-75(C)(8)	_____
KY	_____	_____
MT	Disposal of produced water from oil and gas operations is under the jurisdiction of the Montana Board of Oil and Gas Conservation – See MONT. CODE ANN. § 85-2-510; <i>see also</i> MONT. CODE ANN. § 85-2-403(1).	Production and use of produced water from oil and gas operations is under the jurisdiction of the Montana Board of Oil and Gas Conservation; appropriations of produced water do not pass with the land – See MONT. CODE ANN. § 85-2-510; <i>see also</i> MONT. CODE ANN. § 85-2-403(1).
NM	Working interest owners and operators have ownership of produced water and are responsible for its disposal; ownership and responsibility are transferable – N.M. STAT. ANN. § 70-13-4(1).	Working interest owners and operators have ownership of produced water and are responsible for its disposal; ownership and responsibility are transferable – N.M. STAT. ANN. § 70-13-4(1).
ND	North Dakota Industrial Commission is responsible for regulating the disposal of produced water within the state – N.D. CENT. CODE ANN. § 38-08-04.	_____
OH	_____	_____
PA	_____	_____
TN	Tennessee regulates the disposal and transportation of produced water. Transportation is prohibited without authorization from the state. TENN. COMP. R. & REGS. 0400-45-06-.11(9) and (10).	_____
TX	Permit from Railroad Commission of Texas required for discharges of produced water into water in the state – TEX. WATER CODE § 26.131.	_____
WV	_____	_____
WY	The Wyoming Oil and Gas Conservation Commission has jurisdiction and authority over the disposal of produced water – See WYO. STAT. ANN. § 30-5-104.	Appropriations allowed; application must be filed with state engineer – WYO. STAT. ANN. § 41-3-903; WYO. STAT. ANN. § 41-3-904(a).

Water Acquisition

All states appear to give authority for water condemnation. The states covered in this report all grant some condemnation for water companies, municipal corporations, and public utilities. Interestingly, West Virginia and Tennessee both have specific provisions regarding the condemnation of water for railroad purposes.

WATER CORPORATIONS AUTHORIZED TO EXERCISE EMINENT DOMAIN	
CO	Colo. Rev. Stat. Ann. § 38-6-202(1)
IL	See 70 ILL. COMP. STAT. ANN. 3715; 70 ILL. COMP. STAT. ANN. 3705; 65 ILL. COMP. STAT. ANN. 5/11-124-5
KY	KY. REV. STAT. ANN. § 106.220; <i>see also</i> KY. REV. STAT. ANN. § 416.340 and KY. REV. STAT. ANN. § 96.080
MT	MONT. CODE ANN. § 7-13-4405
NM	<i>Municipalities</i> – See N.M. STAT. ANN. § 3-27-1; <i>see also</i> N.M. STAT. ANN. § 3-27-2 <i>Acequias</i> – N.M. STAT. ANN. § 73-2-2
ND	N.D. CENT. CODE ANN. § 61-01-04
OH	OHIO REV. CODE ANN. § 4933.151 and OHIO REV. CODE ANN. § 719.01.
PA	53 PA. STAT. AND CONS. STAT. ANN. § 5615(a)(1) and 16 PA. STAT. AND CONS. STAT. ANN. § 12907.
TN	TENN. CODE ANN. § 29-17-301
TX	TEX. WATER CODE ANN. § 11.033
WV	W. VA. CODE ANN. § 54-1-2(a)(4)
WY	WYO. STAT ANN. § 41-3-102

REGIONAL SUMMARIES

Regulatory Constraints to Expanded CO₂-EOR and Geologic Storage in the Permian Basin and the Rockies

Owing to its relatively established history of CO₂-EOR operations, developed industrial capture facilities, and natural sources of CO₂ in Colorado and New Mexico, the Interior West region has some of the most extensive CO₂-EOR and geologic storage regulations. The region already has two networks of CO₂ Pipelines, although they are not interconnected. Additionally, CO₂ storage projects are being evaluated in several states.

As recent disputes nationwide have demonstrated, the large amount of federal land interspersed within the interior west makes coordination of private, state, tribal, and federal lands of paramount importance to interstate and regional projects. Areas of inconsistency provide opportunities for state cooperation and legislative action and may also present challenges to implementation of CO₂-EOR policy on a regional basis. However, the growth of CO₂ transportation and injection operations in the region indicates that these differences do not present insurmountable hurdles to commercial projects.

There are fewer regulations regarding direct geologic storage in the region. Furthermore, it is unclear the extent to which judicial interpretations developed in the context of oil and gas and CO₂-EOR would apply to direct storage. Policies and regulations are unclear with respect to potential issues related to transitioning CO₂-EOR projects into direct storage, and comingling CO₂ streams for transportation for both CO₂-EOR and direct storage projects.

Regulatory Constraints to Expanded CO₂-EOR and Geologic Storage in the Appalachian and Illinois Basins

While the Appalachian and Illinois Basin states evaluated have a long and significant history of petroleum and petrochemical production, and an extensive regulatory background in mineral development, the study region has little clear regulation focused on CO₂-EOR, CO₂ pipelines, or CO₂ storage. Geologic feasibility studies and some small field demonstrations for CO₂ enhanced recovery have been performed; however, there is no commercial scale CO₂ utilization activity in the study region.

The regulatory frameworks in the region are relatively similar at the highest levels. Most state policies and regulations are consistent with riparian water rights and dominant mineral estates, and similar history and experience in permitting and regulating mineral extraction. Detailed laws, policies, and regulations can significantly differ from state to state; thus, regional projects will require state cooperation for interstate transport and utilization. More significantly, many states have substantial gaps in their regulatory programs, thus introducing uncertainty and opportunities for legislative action. While commercial projects are feasible, these regulatory gaps are likely significant enough that perceived project risk and uncertainty presents a barrier to field deployment.



“Areas of inconsistency provide opportunities for state cooperation and legislative action and may also present challenges to implementation of CO₂-EOR policy on a regional basis.”

CONSTRAINTS AND OPPORTUNITIES

State and federal lawmakers have an immediate opportunity to address regulatory uncertainty by clarifying key regulatory gaps and inconsistencies. Although in some cases uncertainty arises as a result of judicial interpretation, in the majority of cases the uncertainty arises as a result of incomplete or outdated regulatory frameworks, or lack of clarity regarding whether, and to what extent, existing frameworks would apply to CO₂. The below topics provide lawmakers with opportunities to clarify and expand legislative frameworks to encourage investments in CO₂-EOR and geologic storage.

Appropriation of Produced Water:

Water appropriations in the west are largely administered through the doctrine of prior appropriation. Additionally, most states provide opportunities to appropriate produced water through beneficial reuse. North Dakota is unique in the absence of any clear legal framework for appropriation of produced water.

In the east, the riparian doctrine and reasonable use doctrine apply. However, although recycling of oilfield brine and wastewater is common in these areas, state laws do not clarify ownership and rights of use or transfer in produced water. State laws only address produced water as related to disposal or treatment, principally through the UIC program and the SDWA.

Lawmakers have an opportunity to establish a clear allocation framework for the use of produced water, beyond what is currently in place for disposal. Doing so would promote consistency within the states and regionally, reducing legal uncertainty, and encouraging more efficient water usage and reuse.

Multiple Mineral Estate and Surface-Mineral Conflicts:

Conflicts between development of different mineral estates may pose problems with respect to both CO₂-EOR and geologic storage. State approaches to resolving these disputes differ, and in many areas may be unclear. While North Dakota statutorily authorizes the Industrial Commission to resolve conflicts, most states have no statutory law or common law rules to establish dispute resolution mechanisms. These approaches may also differ from those on adjacent or interspersed federal land.

All of the states studied provide some framework for resolution of disputes between surface and mineral owners with respect to CO₂-EOR. However, potential conflicts may arise between surface and mineral owners regarding the transition of associated storage projects to direct storage or regarding accommodation by the mineral owner for direct storage projects.

Although consistency in state approaches is not required for implementation, state legislatures have an opportunity to consider issues associated with the application of statutory and common law rules for surface-mineral and multiple-mineral conflicts to geologic storage projects.

Local Government Authority:

State approaches to local government authority differ significantly. Whereas Texas statutorily preempts local government regulation of oil and gas, Colorado, Illinois, and Kentucky explicitly authorize local governments to regulate a number of surface development aspects. Most states impliedly preempt much local government regulation, but some local government regulation may be allowed. In all states, the extent of local government authority, if any, over geologic storage operations is unclear. Differences in local government regulations and processes may add to the cost and feasibility of projects. Colorado may pose the greatest current regulatory challenge, as its new legislation empowers local jurisdictions to regulate land use to protect the “public health, safety, welfare and the environment” consistent with existing constitutional protections. Uncertainty regarding local authority over storage operations may add to the cost and feasibility of projects.

Pipeline Common Carriers and Eminent Domain:

Differences in state siting laws for CO₂ enhanced oil recovery (EOR) pipelines have not, thus far, operated as a significant hurdle to development in the west. Pipelines already connect CO₂ sources to oil fields within the region. For example, the Denbury Greencore Pipeline links CO₂ produced in the Lost Cabin and Shute Creek gas plants in Wyoming to the Bell Creek oil field in Montana.¹ Plans call for the Greencore Pipeline to be extended within 2020 to the Cedar Creek Anticline region in Montana and

¹ Melanie D. Jensen et al., *Bell Creek Test Site – Transportation and Injection Operations Report*, PLAINS CO₂ REDUCTION PARTNERSHIP, ENERGY & ENVTL RESEARCH CTR. (2015), <https://undeerc.org/PCOR/technicalpublications/pdf/TR-2015-Bell-Creek-Test-Site-Transportation-and-Injection-Operations-Report.pdf>.

North Dakota.² Similarly, the Cortez and Sheep Mountain Pipelines transport CO₂ from the McElmo Dome and the Sheep Mountain reservoir in Colorado to the Permian Basin in Texas. The Bravo Pipeline transports CO₂ from the Bravo Dome in New Mexico to the Permian Basin.³ Potential new pipelines include a line to connect a carbon capture study project at the Holcim Portland Plant in Florence, Colorado, to oil fields owned by Occidental for CO₂-EOR.⁴ In New Mexico, a project by Enchant Energy at the San Juan Generating Station aims to capture CO₂ for sequestration through either CO₂-EOR or injection into Class VI wells.⁵ However, many of these pipelines have been or will be developed as point-to-point projects, often serving a single source and a single end user.

To date, no interstate CO₂ pipelines exist in the east, and there are few intrastate CO₂ pipelines in the region.

While states with CO₂ pipeline infrastructure have cooperated to allow construction and maintenance of existing pipelines, a more robust and functioning multi-state pipeline network will be necessary for larger or more numerous CO₂-EOR operations and for geologic storage. Although federal safety standards assure a baseline of uniformity, siting processes, eminent domain authority, and common carrier requirements differ. In some cases, the most significant hurdle may be lack of clarity regarding the applicability of existing state laws that do not specifically reference CO₂.

While all states studied allow natural gas pipelines to exercise eminent domain to various extents, it is unclear whether this authority would extend to CO₂ pipelines. Some states, such as New Mexico, Illinois, and

Kentucky, specifically authorize eminent domain for CO₂ pipelines; however, in states where statutory definitions do not specify CO₂, it is unclear whether and to what extent existing regulatory frameworks for natural gas pipelines would extend to CO₂.

Common carrier requirements are not uniform. Common carrier requirements assure that pipelines constructed with eminent domain are available for public use through non-discriminatory access requirements and reasonable rates. While Federal rights-of-way, and laws in all eastern states, Colorado, North Dakota, Montana, Texas, require natural gas pipelines exercising eminent domain to operate as common carriers, Wyoming and New Mexico do not. Thus, it is unclear to what extent unaffiliated shippers could obtain non-discriminatory access to multi-jurisdictional pipelines and, if so, how rate disputes would be resolved.

Liability Transfer:

Liability transfer, a common issue between eastern and western states, is a significant issue for long-term CO₂ storage or sequestration projects. Of the states studied, only North Dakota currently has a state statute providing for liability transfer, although it is unclear to what extent that statute would apply to a multi-state project. Limited programs have been passed in Kentucky⁶ and Illinois,⁷ but both were project-focused and limited to transfers for pilot projects of relatively limited scale.⁸ This lack of clarity on long term liability is a significant barrier to large scale project development, with impacts on project risk and financing, and presents substantial opportunities for multi-state compacts and federal and state legislation.

Federal Pore Space Utilization:

The absence of clear laws and regulations regarding federal pore space utilization for geologic storage poses a significant hurdle to projects of mixed private and federal land. Total CO₂ storage capacity within federal lands is estimated to be substantial. While use of pore space for CO₂-EOR on federal lands is well established, these have limited applicability to geologic storage projects.

NEPA currently presents a significant hurdle to CO₂-EOR projects on federal land. Most, if not all, federal resource management plans currently do not include geologic storage. Amending these resource management

² *Future Tertiary Operations*, DENBURY, <https://www.denbury.com/operations/rocky-mountain-region/tertiary-operations/default.aspx> (last visited Sept. 14, 2020).

³ U.S. DEP'T OF ENERGY, *A Review of the CO₂ Pipeline Infrastructure in the U.S.*, National Energy Technology Laboratory, 4 (Apr. 21, 2015) https://www.energy.gov/sites/prod/files/2015/04/f22/QR%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

⁴ Jordan Blum, *Oxy, Total partner on carbon capture project in Colorado*, HOUSTON CHRONICLE, Jan. 6, 2020, <https://www.houstonchronicle.com/business/energy/article/Oxy-Total-partner-on-carbon-capture-project-in-14952579.php#:~:text=The%20project%20would%20target%20capturing,or%20even%20in%20West%20Texas>. (last visited June 2, 2020).

⁵ Hannah Grover, *NM Tech Receives Funding to Study Carbon Dioxide Storage Near the San Juan Generating Station*, FARMINGTON DAILY TIMES, <https://www.daily-times.com/story/news/local/2020/04/27/nm-tech-receives-funding-san-juan-carbon-dioxide-storage-study/3036807001/> (last visited August 18, 2020).

⁶ KY. REV. STAT. ANN. § 353.810(5) (West 2018).

⁷ 20 ILL. COMP. STAT. ANN. 1108/20 (West 2011).

⁸ KY. REV. STAT. ANN. § 353.804(1) (West 2011).

plans and conducting environmental analysis for geologic storage projects would be costly and time consuming. In some cases, where federal and private lands are intermixed, projects may only involve federal subsurface pore space and have no surface activities. Amending resource management plans to include geologic storage will provide an opportunity to identify conflicts with existing uses and address public concerns. Additionally, expanding categorical exclusions from NEPA to cover storage projects with no surface operations on federal land could streamline federal pore space utilization.

Federal lawmakers and agencies also have an opportunity to expand and clarify the regulatory program for pore space utilization. Section 302(b) of FLPMA gives broad authority for management of public lands, including for uses not specifically forbidden. Expired guidance from 2013 and 2015 indicates that applications for geologic storage projects would fall under 43 C.F.R. § 2920 and require application using Form 2920-1. Use of 43 C.F.R. § 2920 for geologic storage operations, however, is untested. The Department of Interior could provide significant clarity by issuing or reinstating guidance, or initiating rulemaking specific to the processes, terms, and conditions for obtaining rights to use federal land for geologic storage.

Certain aspects of regulation of geologic storage activities on federal land are also unclear. Most notably, federal law does not provide for unitization of pore space for purposes of geologic storage and it is unclear to what extent state pore space unitization processes would apply to federal land. While the Class VI regulatory program provides some guidance, many other regulatory aspects of storage projects are unaddressed in federal law. Rulemaking with respect to federal pore space utilization and geologic storage would streamline projects, especially those including mixed federal and private land.

In addition, there is legal uncertainty regarding the ownership of the pore space in federal “split-estate” lands where the federal government owns the mineral estate and where private individuals own the surface estate. Although this is a relatively small portion of total federal lands, the uncertainty can be a significant issue where federal split estate lands are intermixed with private fee and state lands. For instance, the possibility of federal ownership under a split estate parcel could potentially subject the entire project to NEPA. Although the courts would most likely need to interpret the language in federal statutes in order to establish that pore space is included within federal mineral reservations, federal lawmakers may be able to add clarity regarding the extent to which state law would govern the pore space ownership question on these split-estate lands.



“While all states studied allow natural gas pipelines to exercise eminent domain to various extents, it is unclear whether this authority would extend to CO2 pipelines.”

OPPORTUNITIES FOR FURTHER STUDY

Expansion and development of interstate CO₂ transport will likely be crucial for widespread deployment of CO₂-EOR, CO₂ utilization more generally, or sequestration in the US. While this work has examined comprehensive regulatory and policy factors in the states studied, key geographic gaps exist.

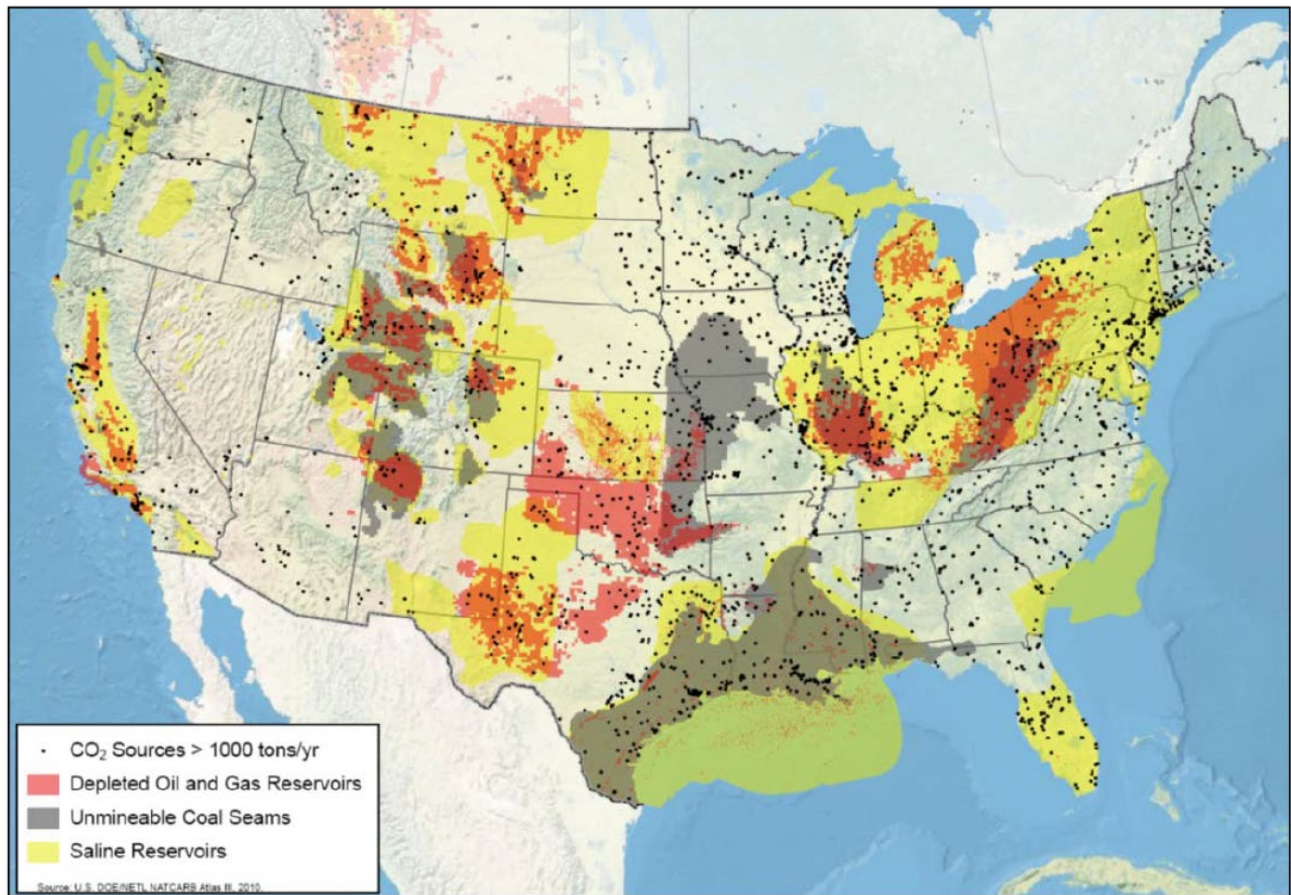


Figure 1. Map of CO₂ sources and likely sinks/utilization reservoirs. Source: Natcarb Database¹

Notable gaps in the eastern region include Indiana and Michigan. Analysis of these two states would provide geographic contiguity connecting CO₂ sources and sinks. Further, a large scale CO₂ capture and sequestration project has been announced by Wabash Valley Resources in Terre Haute, Indiana, targeting 1.5MT/Y in capture and sequestration.² Indiana shares portions of the Illinois Basin oil fields in the southwestern part of the state, and the New Albany Shale gas play in central Indiana, both potential targets for CO₂ utilization.³ In Michigan, the Midwest Carbon Sequestration Partnership (MRCSP) is currently engaged in utilizing CO₂-EOR in the Pinnacle Reef and Antrim Shale region⁴.

In the midwest, significant oil and gas activity exists, combined with large potential sources of CO₂, including ethanol-based CO₂ production. Oklahoma has significant existing oil and gas production, including historic EOR experience, ranking 3rd in natural gas production and 4th in crude oil production in the US.⁵ Kansas holds more than 750MMBbl of technical CO₂-EOR potential and shares geological formations with Oklahoma.⁶

¹ NAT'L ENERGY TECH. LABORATORY, CARBON STORAGE ATLAS, <https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas> (last visited Sept. 8, 2020).

² *WV Resources*, WABASH VALLEY RESOURCES, <https://www.wvresc.com/> (last visited Sept. 8, 2020).

³ John A. Rupp, *A Brief Overview Of The History Of The Petroleum Industry In Indiana*, IND. GEOLOGICAL & WATER SURVEY, <https://igws.indiana.edu/OilGas/> (last visited Sept. 9, 2020).

⁴ *Phase III Project Updates*, MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP, <https://www.mrcsp.org/project-updates> (last visited Sept. 9, 2020).

⁵ MIDWEST GOVERNOR'S ASSOCIATION, CO₂-EOR Potential in the MGA Region (February 26, 2012), <https://www.betterenergy.org/blog/co2-eor-potential-in-the-mga-region/>; U.S. ENERGY INFORMATION ADMINISTRATION, OKLAHOMA, <https://www.eia.gov/state/?sid=OK> (last visited Sept. 9, 2020).

⁶ Crabtree, B., & Christensen, J. (2012). CO₂-EOR Potential in the MGA Region. Great Plains Institute for Sustainable Development Report.

In the southern United States, significant oil and gas activity already exists in Louisiana, Mississippi, Alabama, and Arkansas, and CO₂ pipelines exist connecting the Jackson Dome in Mississippi to Gulf Coast users.⁷ Louisiana is a large producer of both natural gas and oil, ranking 4th in the US in natural gas and 9th in crude oil.⁸ While Alabama and Arkansas have lower levels of production, they are crucial to discussions of any eastern United States CO₂ network that would connect sources and sinks between the Gulf Coast and the Appalachian basin.

In the west, significant opportunities exist for the deployment of enhanced recovery projects in Utah and California, both of which are top ten in oil production and top 15 in natural gas production. Utah provides a ready partner to other states in this Phase 1 study, and has been estimated to have more than two billion barrels of oil that could be recovered through CO₂-EOR.⁹ For California, Arizona, and Nevada, the opportunities are more for connection of sources and sinks. California is a significant producer, ranking 7th in crude oil production and 14th in natural gas production, and has several large point CO₂ sources. Recognizing that California has existent CO₂ cap-and-trade provisions, there may be further market forces to drive CO₂ infrastructure buildout and CO₂ utilization, primarily to reservoirs, both saline and oil and gas, in states to the east.¹⁰ In this model, CO₂ pipelines would necessarily cross Nevada and Arizona.

Study of these states permits analysis on policy conflicts and opportunities for harmonization. More significant regional analyses can also be performed, including examination of potential likely groups of states, based on matching of state parameters and alignment of CO₂ sinks and sources. Expected networks could be envisioned between the Appalachian basin and the Gulf Coast, connecting significant CO₂ sources in both regions with equally significant utilization reservoirs, including as-yet demonstrated opportunities in the Marcellus and Utica shale plays. Other likely networks would include expansion of states contained in the Mountain West/Midwest analysis, such as Utah, Nebraska, Kansas and Oklahoma, connecting significant utilization basins in Texas, Oklahoma, Utah and Colorado with large CO₂ sources in Kansas, Nebraska and Missouri. Tools such as SimCCS could support this continued analysis, allowing for a more holistic analysis of state groups utilizing an economic optimization framework. The research team has been engaged with the developers of SimCCS during the performance of this project, and have identified potential pathways for integrating regulatory and policy information as a parameter in the SimCCS cost surface/allowable pathways framework. This approach would provide guidance on non-technical costs or risks to likely developers, and also provide further ability to focus resources to enable CO₂ transport and utilization.

Through this first phase analysis, the project team has determined that states have significant opportunities—and uncertainties—regarding the development of markets and regulation of CO₂ utilization and storage. A robust second phase analysis will allow planners and policymakers to geographically “connect the dots” but also provides a significant opportunity to identify regional partnerships. These regional analyses could then be used as the impetus to convene groups of relevant, regional stakeholders, project developers, regulatory authorities, and policymakers.

⁷ DENBURY, NATURALLY OCCURRING CO₂ SOURCES, <https://www.denbury.com/operations/gulf-coast-region/co2-sources-and-pipelines/default.aspx> (last visited Sept. 9, 2020).

⁸ U.S. ENERGY INFO. ADMIN., LOUISIANA, <https://www.eia.gov/state/?sid=LA> (last visited Sept. 9, 2020).

⁹ ZHIGIANG GU & MILIND DEO, UTAH GEOLOGIC SURVEY, APPLICABILITY OF CARBON DIOXIDE ENHANCED OIL RECOVERY TO RESERVOIRS IN THE UINTA BASIN, UTAH (2009).

¹⁰ A.B. 398 California Global Warming Solutions Act of 2006, 2017 Leg. (Cal. 2006).

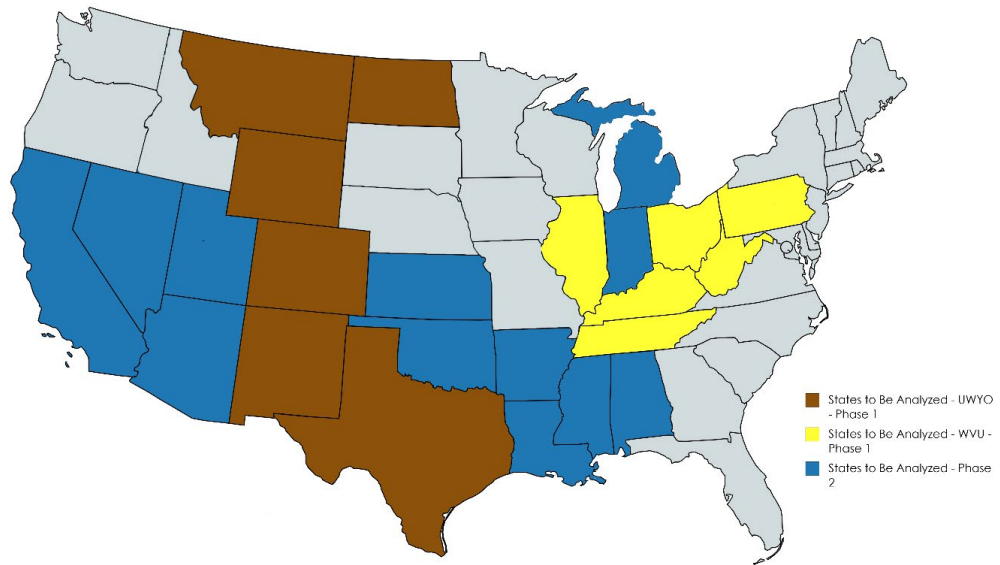


Figure 2. Proposed second phase states in blue. States identified connect regions or have significant CO₂ utilization or capture potential.

CONCLUSION

Regulatory uncertainty and inconsistency present a significant obstacle to widespread implementation of projects and infrastructure for CO₂-EOR and CO₂ storage. 45Q and state and federal policy have increased interest in carbon storage projects, prompting states to evaluate opportunities to expand and revise CO₂ regulatory programs and to identify new potential for carbon storage. These efforts provide an opportunity to harmonize state laws, policies, and regulations and to address regulatory gaps. Where states have no existing CO₂ regulatory programs, lawmakers have an opportunity to enact comprehensive policies addressing, without limitation, unitization for CO₂ projects, pipeline siting authority, pore space ownership, and multiple mineral conflicts. Other states can clarify existing frameworks by specifying the extent to which pipeline and eminent domain laws pertaining to oil and natural gas apply to CO₂ projects. Similarly, there is a significant opportunity for federal lawmakers to encourage more widespread pore space utilization through rulemaking that clarifies the procedures and regulations applicable to carbon storage projects on federal land. Finally, the study finds that in all areas of review, the greatest legal constraints to widespread implementation of CO₂-EOR and geologic storage are issues of coordination rather than inconsistency. Interstate cooperation among regions and federal backstop legislation may streamline project planning.

The findings of this project are necessarily limited by its geographic scope. Additional analysis is needed to fully appreciate the state regulatory landscape and to examine the implementation challenges presented by differential laws and regulations across states and on federal land. We propose additional areas of study of state laws, policies, and regulations on the west coast, in the south east, and in the midcontinent as well as in select states necessary to fill in gaps in the current analysis.



“Regulatory uncertainty and inconsistency present a significant obstacle to widespread implementation of projects and infrastructure for CO₂-EOR and CO₂ storage.”

GLOSSARY

Multiple Mineral Interest Owners

Rule of Capture – This rule stands for the proposition that when a landowner drills a well on his land, he owns all of the oil or gas produced from the well, even where the oil or gas drained or migrated into his well from a neighboring tract of land. Traditionally, landowners could prevent oil and gas located under their land from being produced by someone else by drilling a deeper well than their neighbors. Today, most state regulatory schemes have limited the applicability of the rule of capture through spacing rules, as well as through pooling and unitization agreements or orders. *See* 1 Williams & Meyers, Oil and Gas Law § 204 (2019).

Ownership in place theory – The theory that a landowner owns the oil and gas which was originally in place beneath his surface acreage. Under this theory, the landowner may create by grant or reservation a corporeal or possessory interest in the minerals, separate from the estate in the surface. This theory has been accepted in Arkansas, Kansas, Michigan, Mississippi, Montana, New Mexico, Ohio, Pennsylvania, Tennessee, Texas and West Virginia. Despite the theory of ownership in place, title to the oil and gas in place may be lost by legitimate drainage under the Rule of capture. *See* 1 Williams & Meyers, Oil and Gas Law § 204 (2019).

Correlative Rights – Where an oil or gas reservoir is owned by multiple separate entities, each owner has the right to produce oil or gas from the reservoir. Each owner is also burdened by a duty to the other owners to not commit waste or negligence when engaging in production. These corresponding rights and duties are known as correlative rights. Most regulatory regimes require the protection of correlative rights, which means that the regulatory agency must protect the right of each owner to produce from any given reservoir. *See* Black’s Law Dictionary “correlative-rights doctrine”; *see also* 1 Kuntz, Law of Oil and Gas § 4.3 (2020).

Spacing – Spacing rules regulate the distances between wells, as well as distances between wells and property lines. Most states authorize their oil and gas conservation agency to establish spacing, or drilling, units. Spacing units are areas defined by the conservation agency in which only one well may be drilled. Some states also, or alternatively, allow their conservation agency to create production units, which do not limit the number of wells but rather the amount of oil or gas allowed to be produced in each unit. This has the same effect as a spacing unit where one well can produce the entire amount allowed. By limiting the total amount of wells allowed in a state, spacing rules impact traditional oil and gas operations as well as CO₂-EOR operations. *See* 5 Kuntz, Law of Oil and Gas § 77.2 and .3 (2020).

Pooling – Pooling occurs when separate owners within a spacing unit combine their interests to engage in joint operations. Pooling prevents waste by removing the need for each owner to drill their own well. It also protects correlative rights by allowing each owner to recover their share of production from the single well. Most CO₂-EOR projects involve the oil or gas rights of more than one owner, so would not be viable without pooling. Most states allow either voluntary or forced pooling. *See* 6 Williams & Meyers, Oil and Gas Law § 901 (2019).

Unitization – Unitization is similar to pooling in that it allows multiple owners to operate their interests as if they were one. It differs from pooling in that the separately owned land is not confined to one spacing unit. Rather, it must encompass an entire reservoir or those parts of the reservoir that are useful. Like pooling, it both prevents waste by obviating the need for multiple wells and protects correlative rights by allowing each owner to recover their share of the proceeds. Most CO₂-EOR operations involve reservoirs much bigger than any one spacing unit, so rely on unitization agreements or orders to engage in operations. Additionally, most potential CO₂ storage reservoirs encompass a greater area than a spacing unit and will need unitization agreements in place to operate without violating any owners’ property rights. Most states permit either voluntary unitization agreements or allow their oil and gas conservation agency to order unitization. Texas, however, does not permit the Railroad Commission, its oil and gas conservation agency, to order unitization. *See* 6 Williams & Meyers, Oil and Gas Law § 901 (2019).

Water Rights and Doctrines

Absolute Dominion Rule – “Under this doctrine, a landowner may intercept the groundwater which would otherwise have been available to a neighboring water user and may even monopolize the yield of an aquifer without incurring liability” See, Teresa N. Lukas, *When the Well Runs Dry: A Proposal for Change in the Common Law of Ground Water Rights in Massachusetts*, 10 B.C. Env’tl. Aff. L. Rev. 445, 469 (1982)).

Acre-Foot – The amount of water sufficient to cover one acre of land to a depth of one foot (equal to 43,560 cubic feet or 325,851 gallons). See 5 Waters and Water Rights Special Alert, Glossary of Water Related Terms (2020).

Correlative Rights Doctrine (water) – The Correlative Rights doctrine is based on the Reasonable Use rule. Courts often confuse and combine the two rules. Though often confused, it differs from the Reasonable Use rule in that it does not prohibit off-site uses and uses a proportionality rule. The Correlative Rights doctrine consists of two prongs. First, a water transporter “can protect its right against wasteful or malicious pumping by local users and against interference by other transporters” (Teresa N. Lukas, *When the Well Runs Dry: A Proposal for Change in the Common Law of Ground Water Rights in Massachusetts*, 10 B.C. Env’tl. Aff. L. Rev. 445, 469 (1982)). Second, disputes between local users during times of insufficient supply are settled by a court by allowing each “a fair and just proportion” of the available water (*Katz v. Walkinshaw*, 74 P. 766 (Cal).

Diffused Surface Water – Water that is not within a well-defined waterbody or stream channel, which is lying or flowing along the earth’s surface towards a stream or waterbody. This includes floodwaters, snowmelt and rainfall runoff, as well as seepage. See 5 Waters and Water Rights Special Alert, Glossary of Water and Water Related Terms (2020).

Groundwater – Subsurface water within pores, crevices, and spaces in rock and soil, or which lies within the zone of saturation. See 5 Waters and Water Rights Special Alert, Glossary of Water and Water Related Terms (2020).

Prior Appropriation Doctrine – The prior appropriation doctrine is used primarily in arid western states with limited water supplies. This doctrine basically applies a “first in time, first in right” approach to water appropriation. This means that the first person to divert and put water to a beneficial use has superior right to that water than any other person. Oil and gas developers may obtain water rights through prior appropriation or by purchasing a water right. All prior appropriation states permit transfer of a water right, although some require the consent of the transfer to avoid loss of priority. See 1 Waters and Water Rights § 12.01, .02 and § 14.04 (2020).

Reasonable Use Rule – The Reasonable Use rule (also referred to as the American rule) is a modification of the Absolute Ownership doctrine. The Reasonable Use Rule limits a landowner’s use to beneficial uses having a reasonable relationship to the use of his overlying land. See, *Ground Water: Louisiana’s Quasi-Fictional and Truly Fugacious Mineral*, 44 La. L. Rev. 1123, 1133 (1984)).

The Restatement of Torts Rule – The Restatement of Torts rule (also referred to as the Beneficial Purpose doctrine) merges the English concept of nonliability with the American standard of Reasonable Use. “The result merges prior groundwater law into a standard intended to more equitably meet growing demands on water resources.” See, Juliane Matthews, *A Modern Approach to Groundwater Allocation Disputes: Cline v. American Aggregates Corporation*, 7 J. Energy L. & Pol’y 361 (1986)).

The Restatement (Second) of Torts section 858 provides:

Liability for Use of Groundwater

- (1) A proprietor of land or his grantee who withdraws groundwater from the land and uses it for a beneficial purpose is not subject to liability for interference with the use of water by another, unless
 - (a) the withdrawal of groundwater unreasonably causes harm to a proprietor of neighboring land through lowering the water table or reducing artesian pressure,
 - (b) the withdrawal of groundwater exceeds the proprietor’s reasonable share of the annual supply or total store of groundwater, or
 - (c) the withdrawal of the groundwater has a direct and substantial effect upon a watercourse or lake and unreasonably causes harm to a person entitled to the use of its water.

Riparian Rights – Riparian rights doctrines are used in eastern states with multiple rivers and typically high rainfall. Traditionally, riparian states followed the natural flow theory. Under this theory, a riparian landowner, or landowner who owned river-front land, could use water only to the extent that the water was not diminished in quantity or quality for downstream landowners. Today, most riparian states endorse the reasonable use theory, which posits that all riparian landowners have equal rights to the water, but that each owner may reasonably use the water for beneficial purposes. Under this theory, a riparian owner may not cause “unreasonable injury” to other owners. Riparian rights doctrines usually grant riparian land priority over non-riparian land. Traditional riparian laws forbade the transfer of water rights apart from the land, but today every riparian state allows some form of transfer. *See* 1 Waters and Water Rights § 7.02 and .04 (2020).

Tributary Groundwater – A doctrine used in some prior appropriation states whereby all groundwaters are presumed to be tributary to surface waters. A person appropriating groundwater has the burden to show that it is not a surface tributary. *See* 2 Waters and Water Rights § 19.05 (2020).

Non-Tributary Groundwater – Groundwater that does not have significant hydrological connections to surface water. *See* Colorado State University, Groundwater Rights, <https://waterknowledge.colostate.edu/water-management-administration/water-rights/groundwater-rights/>.

Eminent Domain

Eminent Domain – Eminent domain, also called condemnation power, is the power of a government entity authorized by a government to take private property for a public use. The private property owner is entitled to just compensation for the taking. Common carrier pipeline companies and natural gas utilities are commonly authorized by statute to exercise eminent domain authority.

Subsurface Storage

Pore Space – Pore space can be defined as voids in subsurface geological formations and strata. Several states have legislative definitions for pore space relating specifically to natural gas or CO₂ storage. CO₂ is injected into pore space in CO₂-EOR operations to increase oil recovery and can be left in the pore space for long-term sequestration. *See* 3 Williams & Meyers, Oil and Gas Law Scope (2019); *see also* Michael Godec & Vello Kuuskraa, *CO₂ Storage in Depleted Oil Fields: The Worldwide Potential for Carbon Dioxide Enhanced Oil Recovery*, ENERGY PROCEEDIA (2011).

Geologic Storage – Geologic storage or sequestration is the injection of CO₂ into pore space for long term or permanent storage. Technologically, CO₂ storage is feasible. Development is delayed more by economic viability than problems with the technology. Owen L. Anderson, *Geologic CO₂ Sequestration: Who Owns the Pore Space*, 9 WYO. L. REV. 97 (2009).

Incidental CO₂ Storage – During CO₂-EOR operations, a certain amount of injected CO₂ is “lost” in the subsurface, resulting in its long-term storage in the reservoir. As EOR is the primary purpose of such injection, and not geologic storage, the resulting storage is referred to as incidental or associated. *See* Philip M. Marston, *Incidentally speaking: A Systematic Assessment and Comparison of Incidental Storage of CO₂ During EOR with Other Near-Term Storage Options*, 114 ENERGY PROCEEDIA 7422 – 7430 (2017).

Induced Seismicity – Both withdrawal of fluid from geologic formations and injection into such formations has the potential to trigger earthquakes. Because of this, both oil and gas and CO₂ storage operations may induce seismic activity. While this potential is real, and some states have experienced a correlation between higher earthquake rates and underground fluid storage, most injection wells do not increase the likelihood of earthquakes in their area. *See* 2016-3 RMMLF PROC 2B.

CO₂-EOR Operations

Produced Water – During oil and gas operations, water is often extracted with the oil or gas from geologic formations. This water can have a higher saline content than seawater and may also contain other organic compounds and bacteria. Such produced water may be disposed of through injection into pore space or recycled for a variety of purposes, including secondary oil and gas recovery and road de-icing. Richard W. Healy et al., *The Water-Energy Nexus – An Earth Science Perspective*, USGS (2015).

CO₂-EOR – CO₂ may be injected into oil reservoirs to enhance recovery. The injected CO₂ operates to increase pressure in the reservoir to force unrecovered oil to the operation wells. In deeper formations, injected CO₂ dissolves in the oil and lowers its viscosity, allowing it to flow out of the reservoir more readily. Traditional oil recovery methods typically produce only up to 20% of oil in a reservoir, while secondary recovery methods, such as water injection, recover roughly 15% – 20% more. Enhanced recovery methods, including CO₂-EOR may result in the production of an additional 15% – 20%. Most new CO₂-EOR projects focus on the “miscible” nature of CO₂ in oil rather than increased pressure techniques. See Richard W. Healy et al., *The Water-Energy Nexus – An Earth Science Perspective*, USGS (2015); INSTITUTE FOR 21ST CENTURY ENERGY, CO₂ ENHANCED OIL RECOVERY, U.S. CHAMBER OF COMMERCE, https://www.globalenergyinstitute.org/sites/default/files/020174_EI21_EnhancedOilRecovery_final.pdf (last visited July 23, 2020).

Common Carrier Pipelines - A common carrier pipeline is one that carries substances such as oil, gas, or CO₂, for hire to the public as a public utility. See 8 Williams & Meyers, *Oil and Gas Law Scope* (2019).

Underground Injection Control

EPA Underground Injection Control Program – The EPA maintains an underground injection control (UIC) program under the Safe Drinking Water Act. The UIC program establishes minimum safety standards for injection projects, including CO₂ injection. Under the UIC program, the EPA permits six different classes of wells. The wells are classified according to the type of injection operation, as well as the depth of injection and the associated risk of negative impacts on an underground source of drinking water. See EPA, *Underground Injection Control Regulations and Safe Drinking Water Act Provisions*, <https://www.epa.gov/uic/underground-injection-control-regulations-and-safe-drinking-water-act-provisions>; see also EPA *Underground Injection Control Well Classes*, <https://www.epa.gov/uic/underground-injection-control-well-classes>.

Class II Wells – Wells used to inject fluids for oil and/or natural gas development are referred to as Class II wells. Injected fluids can be saltwater, CO₂, or other fluids. Well types permitted as Class II wells include disposal wells, enhanced recovery wells, and hydrocarbon storage wells. Wells that only produce oil and gas in the absence of any injection procedures are not classified as Class II wells. States may request primacy over Class II wells, but state regulations must at least meet the EPA’s minimum UIC requirements. See EPA, *Class II Oil and Gas Related Injection Wells*, <https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells>.

Class VI Wells – Wells used to inject CO₂ for purely geologic storage purposes are referred to as Class VI wells. The EPA requires Class VI operators to comply with siting rules, construction regulations, and operating and monitoring requirements. Operators must also meet minimum financial requirements and keep satisfactory records. North Dakota is currently the only state with primacy over Class VI wells. See *Class VI – Wells Used for Geologic Sequestration of CO₂*, <https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2>, see also EPA, *Underground Injection Control in EPA Region 8 (CO, MT, ND, SD, UT, and WY)*, <https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy>.

General Terminology

Adverse Possession – Continuous, exclusive, hostile, open, and notorious enjoyment of another’s property with a claim of right. *See* Black’s Law Dictionary “adverse possession.”

Alienable – The status of property that can be transferred by the owner to another. *See* Black’s Law Dictionary “alienable.”

Concurrent covenant – Covenant that requires both parties to perform at the same time. *See* Black’s Law Dictionary “concurrent covenant”

Consideration – “Something . . . bargained for” and received for a promise that is necessary for an agreement to be enforceable. *See* Black’s Law Dictionary “consideration.”

Convey - to transfer ownership of something to another. *See* Black’s Law Dictionary “convey.”

Conveyance – “The voluntary transfer of a right or of property.” Black’s Law Dictionary “conveyance.”

Covenant – “A formal agreement or promise[.]” Black’s Law Dictionary “covenant.

Deed – “A written instrument by which land is conveyed.” Black’s Law Dictionary “deed.”

Divestiture – “The loss or surrender of an asset or interest.” Black’s Law Dictionary “divestiture.”

Divestment – “The cutting short of an interest in property before its normal termination.” Black’s Law Dictionary “divestiture.”

Easement – “An interest in land owned by another person, consisting in the right to use or control the land, or an area above or below it, for a specific limited purpose, such as to cross it for access to a public road; unlike a lease or license, an easement may last forever, but it does not give the holder the right to possess, take from, improve, or sell the land.” Black’s Law Dictionary “easement.”

Exception – “The retention of an existing right or interest, by and for the grantor, in real property being granted to another.” Black’s Law Dictionary, “exception.”

Fee – “A heritable interest in land; especially a fee simple absolute.” Black’s Law Dictionary “fee.”

Fee Simple – “An interest in land that, being the broadest property interest allowed by law, endures until the current holder dies, without heirs; especially a fee simple absolute (often shortened to *fee*.)” Black’s Law Dictionary “fee simple.”

Fee Simple Absolute – “An estate of indefinite or potentially infinite duration[.]” Black’s Law Dictionary “fee simple absolute.”

Forfeiture – “The divestiture of property without compensation.” Black’s Law Dictionary “forfeiture.”

Grant – “An agreement that creates a right or interest in favor of a person or that effects a transfer of a right or interest from one person to another.” Black’s Law Dictionary “grant.”

Grantor/Grantee – A grantor is one who, owning property, conveys it to another. A grantee is one to whom property is conveyed. *See* Black’s Law Dictionary “grantor” and “grantee.”

Habendum Clause – “The part of an instrument, such as a deed or will, that defines the extent of the interest being granted and any conditions affecting the grant.” Black’s Law Dictionary, “habendum clause.”

Implied Covenant – “A covenant that can be inferred from the whole agreement and the conduct of the parties.” Black’s Law Dictionary, “implied covenant.”

In situ – “In place (underlying the surface).” Black’s Law Dictionary, “in situ.”

Lease – “A contract by which a rightful possessor of real property conveys the right to use and occupy the property in exchange for consideration, usually rent.” Black’s Law Dictionary “lease.”

Lessor/Lessee – A lessor is one who owns a property right and leases out to another. A lessee is one who owns a current possessory interest in property under a lease. *See* Black’s Law Dictionary “lessor” and “lessee.”

Mineral Lease – “A lease in which the lessee has the right to explore for and extract oil, gas, and other minerals. The rent is usually based on the amount or value of the minerals extracted.” Black’s Law Dictionary “mineral lease.”

Mining Lease – “A lease of the mine or mining claim, in which the lessee has the right to work the mine or claim, usually with conditions on the amount and type of work to be done. The lessor is compensated with either fixed rent or royalties based on the amount of ore mined.” Black’s Law Dictionary, “mineral lease.”

Partition – Division of real property owned by more than one party either as joint tenants or tenants in common into individually owned interests. *See* Black’s Law Dictionary “partition.”

Real estate – “Property made up of land and the buildings on it, as well as the natural resources of the land including uncultivated flora and fauna, farmed crops and livestock, water, and any additional mineral deposits.” Black’s Law Dictionary “real estate.”

Real property – “Fixed property, principally land and buildings.” Black’s Law Dictionary “real property.”

Realty – “Land and anything growing on, attached to, or erected on it that cannot be removed without injury to the land.” Black’s Law Dictionary “realty.”

Reduced to possession – “Conversion of a right existing as a claim into actual custody and enjoyment.” Black’s Law Dictionary “reduced to possession.”

Rent – “Consideration paid, usually periodically, for the use or occupancy of property, especially real property.” Black’s Law Dictionary “rent.”

Right-of-way – “The right to pass through property owned by another.” Black’s Law Dictionary “right-of-way.”

Royalty – “A share of the product or profit from real property, reserved by the grantor of a mineral lease, in exchange for the lessee’s right to mine or drill on the land.” Black’s Law Dictionary “royalty.”

Tenancy – “The possession or occupation of land under a lease’ a leasehold interest in real estate . . . The period of such possession or occupancy.” Black’s Law Dictionary “tenancy.”

Tenants in common – “A tenancy of two or more persons, in equal or unequal divided shares, each person having an equal right to possess the whole property but no right of survivorship.” Black’s Law Dictionary “tenants in common.”

Usufructuary Right – A right to use another’s property or possession for a certain time, but without any right to destroy or damage the property. *See* Black’s Law Dictionary “usufruct” and “usufructuary.”

Vest – “To confer ownership (of property) on a person.” Black’s Law Dictionary “vest.”