

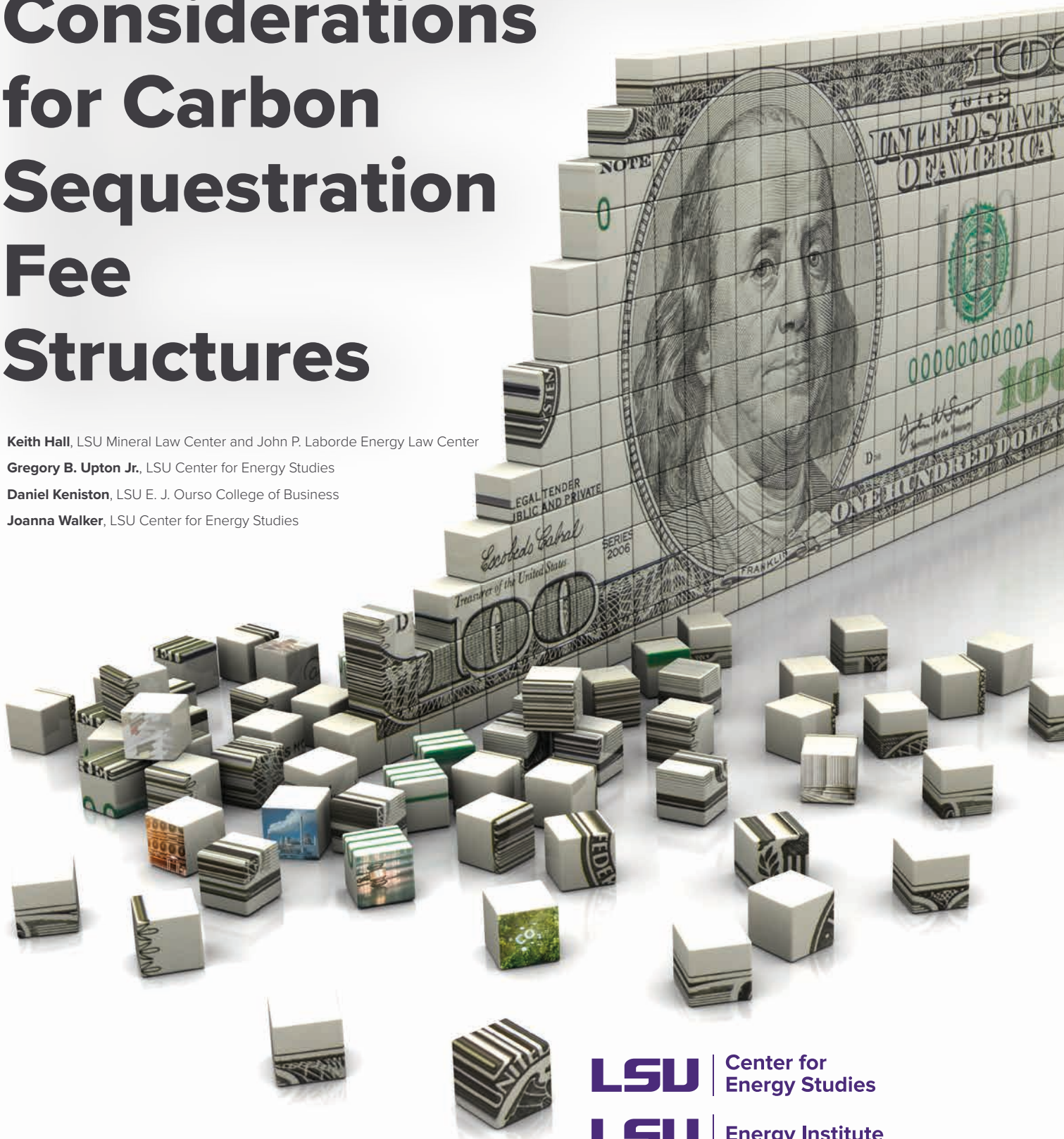
Legal and Regulatory Considerations for Carbon Sequestration Fee Structures

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Carbon capture and storage (CCS) refers to the process by which carbon dioxide (CO₂) is captured from industrial or other sources, transported—typically via pipeline—and injected into deep geologic formations for long-term subsurface storage. CCS is a subset of the broader category of carbon capture, utilization, and storage (CCUS), which also includes cases where CO₂ is put to a commercial use rather than being permanently sequestered. As CCS deployment expands in the United States and elsewhere, a range of legal, regulatory, and economic considerations has emerged concerning the use of subsurface pore space for CO₂ storage.

This white paper reviews legal and regulatory frameworks in Louisiana, as well as a broader U.S. context, associated with the acquisition of pore space rights and the compensation of landowners and governments in connection with CCS projects. While there are points of comparison with traditional oil and gas activities—particularly regarding subsurface property use—CCS presents distinct legal questions. These include issues related to subsurface ownership, the potential for trespass arising from lateral migration of injected CO₂, and the allocation of costs and benefits among parties with and without contractual agreements.

The discussion begins with an overview of why CCS operators may need to secure legal rights to subsurface pore space, including property law doctrines such as *ad coelum* and the legal basis for trespass claims. It then outlines the types of agreements commonly used to obtain pore space rights—such as leases, servitudes, and other instruments—and the associated compensation structures. Finally, the paper examines statutory mechanisms, including unitization and eminent domain, that may be used where voluntary agreements are not achieved.

I. What is carbon capture and storage?

Carbon capture and storage (“CCS”) is the *capture* of carbon dioxide (CO₂)—either directly from the atmosphere or from industrial emissions—followed by transport of the CO₂ to an injection site and then the injection of the CO₂ deep into the subsurface of the earth for permanent *storage* in the pore spaces of geologic formations.

Carbon capture and storage or CCS is sometimes called “carbon capture and sequestration.”¹ CCS is a subset of a broader concept called carbon capture, utilization and storage (“CCUS”), which refers both to CCS and the possibility of capturing CO₂ and then putting it to some use, rather than injecting it in the subsurface for permanent storage.²

¹ Other terms that are slight variations of “carbon sequestration” are also used, such as “CO₂ sequestration,” “carbon sequestration,” or “carbon capture and sequestration,” or the “geological sequestration of carbon dioxide.” For example, when Louisiana adopted CCS legislation in 2009, the legislation was called the “Louisiana Geological Sequestration of Carbon Dioxide Act.” See La. Rev. Stat. 31:1101. See also Christopher J. Miller, *Carbon Capture and Sequestration in Texas: Navigating the Legal Challenges Related to Pore Space Ownership*, 6 Tex. J. Oil Gas & Energy L. 399 (2010-11). Some sources referred to “CO₂ Sequestration” or “Sequestration of Carbon Dioxide.” See, e.g., Owen L. Anderson, *Geologic CO₂ Sequestration: Who Owns the Pore Space?*, 9 Wyo. L. Rev. 97 (2009); now, however, it is more common to refer to the process as “carbon capture and storage.” See, e.g., Ken. Rev. Stat. § 353.804 (statute enacted in 2021 referring to “carbon capture and storage technology” and “a carbon capture and storage project”).

² A related concept is enhanced oil recovery (“EOR”), sometimes called “tertiary recovery.” EOR involves the injection of some substance into an oil formation, after primary recovery and perhaps secondary recovery techniques are no longer economical, but a field still contains oil. Often, the substance injected in EOR is CO₂. EOR generally uses numerous wells, some of which are injection wells and some of which are recovery wells. The CO₂ injected via the injection wells provides a sweeping effect that pushes oil toward the recovery wells. In addition, some of the CO₂ dissolves into the oil, decreasing the oil’s viscosity, so that it flows more easily. A combination of oil and CO₂ is recovered via the recovery wells. The CO₂ is separated from the oil and recycled for re-injection, along with additional CO₂ that is needed because much of the CO₂ remains underground. The oil is marketed.

II. Why the CCS operator needs to acquire pore space rights from the landowner

The general rules of property law applicable to land explain why a CCS operator needs to acquire pore space rights from the landowner. Below, this white paper discusses those general rules, then addresses circumstances in which someone other than the landowner has the right to use the land to explore for and produce minerals, such as oil and gas.

A. General rules of property law relevant to the subsurface

When a CCS operator injects CO₂ into the subsurface, some of the CO₂ will migrate laterally—sideways, in a sense—through the formation. In many cases, this lateral migration will result in a portion of the CO₂ entering pore spaces beneath the land of neighboring property owners. This could be a problem, given the application of two legal principles.

The first of these principles is a property law doctrine which states that a landowner owns, at least in theory, all the airspace above the land and the entire subsurface below it, all the way to the center of the earth.³ This principle is stated for Louisiana property law by Civil Code article 490, which states in part: “Unless otherwise provided by law, the ownership of a tract of land carries with it the ownership of everything that is directly above or under it.” The same principle applies in the common law, and is given a name, the *ad coelum* doctrine. This name comes from a Latin phrase, “*cujus est solum ejus est usque ad coelum et ad inferos*,” that has been used by Blackstone and others to express the doctrine.⁴ The phrase has been translated as: “For whoever owns the soil, it is theirs up to Heaven and down to Hell.”⁵

The second principle is the rule that a landowner generally has the right to exclude others from the land.⁶ One of the ways to vindicate this right is to bring an action for trespass when someone violates this right.⁷ When there has been a trespass, a landowner typically can obtain a money judgment to compensate for any actual damages that the trespasser has caused.⁸ If the trespasser did not cause damage, the landowner may be able to obtain an award of nominal damages to vindicate his or her right

³ Thrasher v. City of Atlanta, 173 S.E. 817, 825 (Ga. 1934).

⁴ 2 WILLIAM BLACKSTONE, COMMENTARIES.

⁵ Alyce Gaines Johnson Special Trust v. El Paso E & P Co., L.P., 773 F.Supp.2d 640, 645 (W.D. La. 2011).

⁶ Louisiana Civil Code article 477 states in part: “Ownership is the right that confers on a person direct, immediate, and exclusive authority over a thing.”

Sources outside Louisiana support the same principle. See 2 WILLIAM BLACKSTONE, COMMENTARIES *2 (defining ownership as “that sole and despotic dominion which one man claims and exercises over the external things of the world, in total exclusion of the right of any other individual in the universe.”); see also Cedar Point Nursery v. Hassid, 141 S. Ct. 2063, 2072 (2021) (stating that “...the right to exclude is ‘universally held to be a fundamental element of the property right,’ and is ‘one of the most essential sticks in the bundle of rights that are commonly characterized as property.’” (quoting Kaiser Aetna v. United States, 444 U.S. 164, 176, 179–180 (1979)); Lightning Oil Co. v. Anadarko E&P Onshore, 520 S.W.3d 39, 46 (Tex. 2017) (explaining that the “owner of realty generally ‘has the right to exclude all others from use of the property.’”); Sammons v. Am. Auto. Ass’n, 912 P.2d 1103, 1105 (Wyo. 1996) (stating that “[o]wnership of property implies the right of possession and control and includes the right to exclude others; that is, a true owner of land exercises full dominion and control over it and possesses the right to expel trespassers.”); Guimont v. Clarke, 854 P.2d 1, 6 (Wash. 1993) (referring to the right to exclude others as one of the “fundamental attributes of property ownership”); State v. Hall, 47 P.3d 55, 57 (Or. Ct. App. 2002) (stating the general rule that “one of the incidents of property ownership is the right to invite other persons to use property or, conversely, to exclude them from doing so.”).

⁷ An action for trespass protects the right of possession, rather than ownership. W. PAGE KEETON ET AL., PROSSER AND KEETON ON THE LAW OF TORTS § 13, at 77 (5th ed. 1984) (stating that the “action for trespass is designed to protect the interest in exclusive possession of the land in its intact physical condition.”); Florig v. Estate of O’Hara, 912 A.2d 318, 327 n.13 (Pa. Super. Ct. 2006) (citing Roncace v. Welsh, 14 A.2d 616, 617 (Pa. Super. Ct. 1940)). However, the owner of land generally has the right to possess the land and a right to exclude others. See Babb v. Lee Cnty. Landfill SC, LLC, 747 S.E.2d 468, 473 (S.C. 2013) (explaining that a trespass is “any interference with ‘one’s right to the exclusive, peaceable possession of his property’”) (quoting Ravan v. Greenville Cnty., 434 S.E.2d 296, 306 (S.C. Ct. App. 1993)); Johnson v. Paynesville Farmers Union Coop. Oil Co., 817 N.W.2d 693, 701 (Minn. 2012). When land is leased, the lessee might be the proper party (rather than the owner) to bring a trespass action. See Bascom v. Dempsey, N.E. 744, 744–45 (Mass. 1887) (lessor who was not in possession could not maintain a valid trespass action). Further, if someone other than the landowner has wrongfully established possession, the landowner may not have a trespass claim, though the landowner may have the right to bring an ejectment action that would force the possessor to leave. KEETON, LAW OF TORTS § 13, at 77. If the owner does not possess the land, but no one else has established possession, the landowner likely has constructive possession and therefore could bring an action in trespass against an intruder. See *id.*

⁸ See, e.g., Smith v. Carbide & Chems. Corp., 226 S.W.3d 52, 56–57 (Ky. 2007) (holding that an intentional trespass qualifies as a harm sufficient for a plaintiff to obtain actual damages); Whitten v. Cox, 799 So. 2d 1, 18 (Miss. 2000) (acknowledging that a trespass alone qualifies as a harm sufficient to obtain at least nominal damages but that “in order to recover more than nominal damages, actual damages must be shown.”) (quoting Chevron Oil Co. v. Snellgrove, 175 So. 2d 471, 474 (Miss. 1965)).

of exclusive possession.⁹ If the trespass does not cause harm, but the trespass is continuing or repeated, the landowner may be entitled to injunctive relief to require the cessation of an ongoing trespass or to enjoin a repetition of the trespass.¹⁰ However, the award of injunctive relief is discretionary, and a court may decline to award injunctive relief if such relief would be adverse to the public interest.¹¹

Numerous courts have relied on the *ad coelum* doctrine in holding that a defendant incurred trespass liability for an unauthorized intrusion of the airspace above or the subsurface below a plaintiff's land.¹² For example, courts have held that a plaintiff has a cause of action for airspace intrusions by portions of a defendant's building, such as eaves,¹³ cornices,¹⁴ and roofs,¹⁵ that extended over the property line and above a plaintiff's land. At least one court has held that wires passing over a plaintiff's property constituted a trespass,¹⁶ and one court even held that a defendant committed a trespass when she extended her arm over the property line.¹⁷

Courts have also held that a company commits a subsurface trespass if it drills a slant well that bottoms below the plaintiff's land without authority to do so.¹⁸ Courts have held that a person who enters a cave opening on his property, then walks through a portion of the cave that is beneath his neighbor's property commits a trespass.¹⁹ Some courts have imposed trespass liability based on a subsurface migration of contaminants.²⁰ And one court concluded that the intrusion of hydraulic fracturing fluid into the subsurface of the plaintiffs' tract would constitute a trespass.²¹ Similarly, the Restatement (Second) of Torts recognizes that a trespass can occur above or below the surface.²²

Despite these court decisions that have upheld the *ad coelum* doctrine in certain circumstances, it also is clear that courts do not always apply the *ad coelum* doctrine literally. It is well established, for example, that high altitude air travel does not make the operator of an airplane liable in trespass to the owners of all the tracts of land along the flight path of the airplane. Similarly, courts often have declined to impose subsurface trespass liability against defendants who engaged in injection disposal operations.

Injection disposal became a common method to dispose of liquid wastes as early as the 1930s.²³ It was first used as a common method to dispose of brine generated during oil and gas activity, but in the 1950s it became common to dispose of other types of fluid wastes by injection disposal.²⁴ In this process,

⁹ See Whitten, 799 So. 2d at 18; see also *Coastal Oil & Gas Corp. v. Garza Energy Tr.*, 268 S.W.3d 1, 12 n.36 (Tex. 2008) (noting that a "trespass against a possessory interest . . . may result in an award of nominal damages") (citing *McDaniel Bros. v. Wilson*, 70 S.W.2d 618, 621 (Tex. Civ. App. 1934)); Whitten v. Cox, 799 So. 3d 1, 18 (Miss. 2000) (reversing lower court's judgment failing to award any damages for trespass, rendering judgment for \$10 as nominal damages).

¹⁰ See *Gilbert Wheeler, Inc. v. Enbridge Pipelines (E. Tex.)*, L.P., 449 S.W.3d 474, 478 n.1 (Tex. 2014) (citing R.R. Comm'n of Tex. v. Manziel, 361 S.W.2d 560, 567 n.2 (Tex. 1962)); *City of Providence v. Doe*, 21 A.3d 315, 319–20 (R.I. 2011) (explaining that the standard for injunctive relief "when the underlying harm derives from an incident of continuing trespass is well established and provides that '[a] continuing trespass wrongfully interferes with the legal rights of the owner, and in the usual case those rights cannot be adequately protected except by an injunction which will eliminate the trespass.'" (quoting *Santilli v. Morelli*, 230 A.2d 860, 863 (R.I. 1967)); *Hobbs v. Mobile Cnty.*, 72 So. 3d 12, 18 (Ala. 2011) (citing *Town of York v. McAlpin*, 167 So. 539, 539–40 (Ala. 1936)); *S.L. Garand Co. v. Everlasting Memorial Works, Inc.*, 264 A.2d 776, 778 (Vt. 1970); *Allred v. Harris*, 18 Cal. Rptr. 2d 530, 533 (Cal. Ct. App. 1993).

¹¹ See *Madison v. Ducktown Sulphur, Copper & Iron Co.*, 83 S.W. 658, 666–67 (Tenn. 1904) (awarding damages but denying injunctive relief, in part because of the public interest in allowing a continuance of the challenged activities).

¹² See *Hannabalsen v. Sessions*, 90 N.W. 93, 95 (Iowa 1902) (intrusion into airspace was a trespass); *Hastings Oil Co. v. Texas Co.*, 234 S.W.2d 389, 398 (Tex. 1950) (intrusion into subsurface was a trespass); see also RESTATEMENT (SECOND) OF TORTS § 159 (AM. L. INST. 1965) (a trespass may occur "on, beneath, or above the surface of the earth.").

¹³ See *Huber v. Stark*, 102 N.W. 12, 12 (Wis. 1905) (intrusion of eaves over plaintiff's property is an actionable trespass); see also *Butler v. Frontier Telephone Co.*, 79 N.E. 716, 717 (N.Y. 1906) (noting decisions that support imposing trespass liability for intrusion of eaves over property).

¹⁴ See *Harrington v. McCarthy*, 48 N.E. 278, 278 (Mass. 1897).

¹⁵ See *Murphy v. Bolger*, 15 A. 365, 368 (Vt. 1888).

¹⁶ See *Butler*, 79 N.E. at 718; see also *Marcus Cable Assocs., L.P. v. Krohn*, 90 S.W.3d 697, 703 (Tex. 2002) (unauthorized intrusion of wires over landowner's property was a trespass).

¹⁷ See *Hannabalsen*, 90 N.W. at 95.

¹⁸ See *Hastings Oil Co. v. Texas Co.*, 234 S.W.2d 389, 398 (Tex. 1950); *Gliptis v. Fifteen Oil Co.*, 16 So. 2d 471, 474 (La. 1944); *Alphonzo E. Bell Corp. v. Bell View Oil Syndicate*, 76 P.2d 167, 177–78 (Cal. Dist. Ct. App. 1938).

¹⁹ See, e.g., *Edwards v. Sims*, 24 S.W.2d 619, 620–21 (Ky. 1929); see also *Edwards v. Lee's Adm'r*, 96 S.W.2d 1028, 1029–30 (Ky. 1936) (affirming a finding of trespass).

²⁰ See *Beck v. N. Nat. Gas Co.*, 170 F.3d 1018, 1022 (10th Cir. 1999); *Hoery v. United States*, 64 P.3d 214, 216 (Colo. 2003).

²¹ See *Stone v. Chesapeake Appalachia, LLC*, 2013 WL 2097397 (N.D. W. Va.).

²² RESTATEMENT (SECOND) OF TORTS § 158 (AM. L. INST. 1965).

²³ See *General Information About Injection Wells*, Env't Prot. Agency, <https://www.epa.gov/uic/general-information-about-injection-wells> [<https://perma.cc/2S3F-MXEU>] (last updated Aug. 2, 2022).

²⁴ *Id.*

an operator pumps the liquid waste down an injection well and out into a subsurface formation.²⁵ The process is the opposite of what happens in the production of oil from an oil well or water from a water well.²⁶ In injection disposal, an operator pumps liquid waste down a well and into a permeable formation.²⁷ As liquid waste continues to be pumped down the well and into the formation, the liquid waste will migrate through the formation, and the liquid that is exiting the well pushes other liquid already in the formation further out, away from the well and into the formation.²⁸ If enough waste liquid is injected into the formation, the waste fluid can migrate far enough to cross subsurface property lines.²⁹

In several cases, landowners have sued, alleging that a defendant's injection disposal operation has caused a subsurface trespass of waste fluids.³⁰ In most of those cases, courts have held that a plaintiff does not have a cause of action for subsurface trespass action merely because fluids migrated into the subsurface of his property.³¹ To sustain a cause of action for subsurface trespass in such cases, a plaintiff must show actual damages or an interference with some reasonably anticipated use of his property.³²

One of the best known cases is *Chance v. BP Chemicals, Inc.*, in which plaintiffs brought a class action, asserting trespass claims based on allegations that the defendant's injection disposal operation caused waste fluids to migrate into the subsurface of the plaintiffs' properties.³³ After a jury found that the plaintiffs had failed to prove actual damages or an unreasonable interference with a foreseeable use of their properties, the trial court entered judgment for the defendant.³⁴ The appellate court affirmed, and the Ohio Supreme Court agreed to review the case.³⁵

The plaintiffs argued that proof of a subsurface intrusion was sufficient to prove a trespass because proof of actual damages generally is not required in a trespass action.³⁶ The Ohio Supreme Court rejected that argument, stating that the *ad coelum* doctrine "has no place in the modern world."³⁷ The Court quoted from a case in which the Ninth Circuit stated that a person's ownership of the airspace above his land extends only so far as the space he can use and occupy.³⁸ The Ohio Supreme Court agreed and concluded that similar reasoning applies for the subsurface.³⁹ Therefore, in order for a plaintiff to recover in trespass for an intrusion caused deep beneath the subsurface by an injection disposal operation, plaintiffs must prove "physical damage or actual interference with the reasonable and foreseeable use of the properties."⁴⁰ Because the plaintiffs in *Chance* had not proven damages or interference with use, the Ohio Supreme Court affirmed the judgment against them.⁴¹

Thus, a court might hold that the migration of CO₂ into pore spaces of neighboring lands, without consent

²⁵ *Id.*

²⁶ Environmental Protection Agency, *Compare Class II Oil and Gas Related Injection Wells*, <https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells> [<https://perma.cc/2ZVS-RVYX>] (last updated Aug. 2, 2022) (discussing production process from oil wells via hydraulic fracking), with ENV'T PROT. AGENCY, EPA 816-R-01-007, CLASS I UNDERGROUND INJECTION CONTROL PROGRAM: STUDY OF THE RISKS ASSOCIATED WITH CLASS I UNDERGROUND INJECTION WELLS (2001) [hereinafter EPA CLASS I WELL STUDY] (detailing the injection disposal process).

²⁷ EPA CLASS I WELL STUDY, *supra* note 141.

²⁸ *Id.*

²⁹ *Id.* at 13.

³⁰ See, e.g., *West Edmond Salt Water Disposal Ass'n v. Rosecrans*, 226 P.2d 965 (Okla. 1950) (in which a class action was filed for subsurface salt water intrusions); *Baker v. Chevron USA, Inc.*, 2009 WL 3698419 (S.D. Ohio 2009) (in which a class action was filed against Chevron for subsurface petroleum intrusions).

³¹ *Baker*, 2009 WL 3698419 at *7.

³² *Rosecrans*, 226 P.2d at 968.

³³ *Chance v. BP Chems., Inc.*, 670 N.E.2d 985, 986 (Ohio 1996).

³⁴ *Id.* at 989.

³⁵ *Id.* at 990.

³⁶ *Id.* at 993.

³⁷ *Id.* at 991 (citing *Vill. of Willoughby Hills* 278 N.E.2d at 664).

³⁸ *Id.* at 992.

³⁹ *Id.* at 992 (also observing that "ownership rights in today's world are not so clear-cut as they were before the advent of airplanes and injection wells").

⁴⁰ *Id.* at 993.

⁴¹ *Id.* at 994.

of the neighboring landowners, is not a trespass if the migration does not cause harm.⁴² On the other hand, a court might conclude otherwise, holding that such a migration is a trespass, even if it does not cause harm, and, because such a migration likely would constitute a continuing trespass (assuming it is a trespass at all), a landowner might be able to obtain an injunction forcing the CCS operator to halt CO₂ injections. Given the high costs of CCS projects, prospective CCS operators are unlikely to invest millions in capital on a CCS project and sign long-term agreements with emitters to sequester carbon, without acquiring pore space rights via agreement or other means.⁴³

B. Circumstances in which someone other than the landowner has the right to explore for and produce minerals

In the discussion immediately above, this White Paper explained why a CCS operator is advised to acquire pore space rights from the landowner, focusing on the fact that ownership of land is generally deemed to include ownership of the subsurface beneath it, and that the intrusion of an injected substance into the subsurface without the landowner's consent might be a trespass. But the discussion above did not address the possibility that, even if the subsurface generally is owned by the landowner, the landowner or former owner of the land might have severed the rights to the subsurface from ownership of the surface.

Of course, if a landowner already has granted a pore space lease (or a pore space servitude, or an easement in a state other than Louisiana), and that grant is recorded in the public record, so that it has effect as to third persons,⁴⁴ the landowner cannot grant a subsequent, viable pore space lease for the same formation and area, that the new leaseholder can enforce while the prior lease remains in effect. Probably no one would question that.

But many people have asked another question. If someone other than the landowner has rights to explore for and produce minerals—for example, when the landowner has granted a mineral lease or mineral servitude, or in another state a landowner has created a severed mineral estate in favor of some other person—and the agreement that conferred mineral rights on someone else is silent about subsurface storage rights, do the subsurface storage rights belong to the landowner or the person with mineral rights?⁴⁵ Although few state supreme courts have expressly ruled on this, the answer in Louisiana and most other states almost certainly is that the landowner owns the right to use the subsurface for storage (at least for storing substances other than waste products from mineral operations conducted on the land by the person having mineral rights). A thorough discussion of this question is beyond the scope of this White Paper, but the available authority from court decisions and legal scholars is virtually unanimous in support of the conclusion that the landowner, not the mineral owner, owns subsurface storage rights.

⁴² The possibility that a landowner might not be entitled to relief for the subsurface migration of fluids will not be discussed any further in this Paper because it has been thoroughly discussed elsewhere. See, e.g., Owen L. Anderson, *Lorde Coke, the Restatement, and Modern Subsurface Trespass Law*, 6 Tex. J. Oil Gas Energy L. 203 (2010-11); Owen L. Anderson, *Geologic CO₂ Sequestration: Who Owns the Pore Space?*, 9 Wyo. L. Rev. 97 (2009); Joseph A. Schremmer, *Pore Space Property*, 2021 Utah L. Rev. 1 (2021); Christopher S. Kulander and R. Jordan Shaw, *Comparing Subsurface Trespass Jurisprudence—Geophysical Surveying and Hydraulic Fracturing*, 46 N.M. L. Rev. 67 (2016). See also Keith B. Hall, *Hydraulic Fracturing: If Fractures Cross Property Lines is there an Actionable Subsurface Trespass?*, 54 Nat. Res. J. 361 (Fall 2014); Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 228.

⁴³ Indeed, evidence to date shows that CCS operators are doing just that—they are seeking to obtain pore space rights, by agreement or other means. And, as it becomes customary for CCS operators to acquire pore space rights, this practice of implicitly recognizing the landowner's rights will only increase the likelihood that a court, in a contested case, would conclude that the migration of CO₂ into the subsurface of land, without the landowner's consent or some other authorization, constitutes a subsurface trespass.

⁴⁴ As a general rule, written agreements transferring or affecting interests in land are binding as between the parties to the agreement. La. Civ. Code arts. 517, 1839. But a written agreement transferring or affecting interests in land generally are not effective as to third persons unless the agreements are recorded in the conveyance records (or mortgage records) of the parish in which the land is located. La. Civ. Code arts. 517, 1839, 3338, 3346.

Suppose, for example, that A is a landowner who grants a lease to B, but B never records its lease. While the lease to B is still in effect, A grants a lease to C, who records its lease. In a dispute between B and C over access to the leased premises, C should prevail. B may have a valid claim against A for A's breach of B's lease, but C should prevail over B in the dispute between B and C.

⁴⁵ If those mineral rights are still in effect, and the mineral lease, or the instrument that creates the mineral servitude or severed mineral estate, expressly granted subsurface storage rights, the grant of subsurface storage rights generally would be enforceable. Again, probably no one disputes this and probably few people even question this.

For example, the first sentence of Louisiana Civil Code article 490 states: “Unless otherwise provided by law, the ownership of a tract of land carries with it the ownership of everything that is directly above or under it.” Nothing in the law provides for separate ownership of pore spaces. Further, the Louisiana Mineral Code article 5 (La. Rev. Stat. 31:5) expressly states that no one but the landowner can own subsurface minerals naturally in place underground: “Ownership of land includes all minerals occurring naturally in a solid state. Solid minerals are insusceptible of ownership apart from the land until reduced to possession.” Thus, the landowner owns the subsurface rocks in which minerals are found.

If the landowner necessarily owns the solid rock matrix surrounding pore spaces, as required by Mineral Code article 5, and the landowner generally owns everything under the land, as specified by Civil Code article 490, it is reasonably clear that the pore spaces belong to the landowner. In addition, the second sentence of Civil Code article 490 states the owner of land may make works on, above, or below the land as he pleases, and draw all the advantages that accrue from them, unless he is restrained by law or by rights of others.” If someone other than the landowner has mineral rights in the land, the landowner must exercise his rights—including his right to use the subsurface—with reasonable regard to the rights of any other person to explore for and produce minerals (this is required by Mineral Code article 11). Subject to the landowner’s “reasonable regard” duty, the landowner generally would be free to use the subsurface for storage.

Although the ownership of subsurface pore space has not been addressed in Louisiana caselaw, an arguably analogous issue—the ownership of a subsurface salt dome cavern—has been litigated. In *United States v. 43.42 Acres of Land*, 520 F. Supp. 1042 (W.D. La. 1981), the federal government was using eminent domain authority to acquire certain land where salt domes were located. The government wanted the land so that it could create subsurface caverns within the salt dome,⁴⁶ then use the caverns to store oil for the Strategic Petroleum Reserve. One of the tracts of land being acquired was burdened by a mineral servitude,⁴⁷ and the landowners and servitude owners disagreed regarding the allocation of the compensation that the government would pay.

There was little dispute that the persons who held the mineral servitude were entitled to compensation for the mineral exploration and production rights being taken from them, and the landowners had a right to compensation for the land being taken from them. And, to the extent that the land had extra value because of its usefulness for subsurface storage in salt dome caverns, the government would need to compensate the person who had the right to use the land for that purpose. But, from whom was the right to use salt dome caverns for storage being taken, from the landowners or from the persons who held the mineral servitude? The mineral servitude owners asserted that they had a right to mine salt, because it is a mineral, and therefore it would own any cavern created by removing the salt. The landowner disagreed, asserting that it owned everything beneath the surface.

The court agreed with the landowners. The court noted that a mineral servitude owner has the right to use the land for the exploration and production of minerals, but he does not own the land itself or the

⁴⁶ A court described the process for making the salt dome caverns as follows:

To utilize the subsurface for the extraction of brine and the creation of storage facilities a well similar to the usual oil or gas well is drilled so as to penetrate the salt formation. Water is forced into the formation through the well, the salt is withdrawn as brine, and a cavity is left in the salt mass because of gradual dissolving of the salt and a resulting erosion by the leaching process. The jugshaped cavity, or ‘jug’ formed by this leaching is used for the storage of hydrocarbons. A jug is 100 feet or more in diameter and 1000 feet or more in depth, with capacity for storing over a million barrels of one of the various hydrocarbons. A thick barrier of salt must be retained around each jug to form a satisfactory wall for the containment of the stored product.

Louisiana Power & Light Co. v. United Lands Co., 228 So. 2d 140, 142 (La. 1969).

⁴⁷ “A mineral servitude is the right of enjoyment of land belonging to another for the purpose of exploring for and producing minerals and reducing them to possession and ownership.” La. Min. Code art. 22 (La. Rev. Stat. 31:22). Louisiana does not allow the creation of severed mineral estates, *Wemple v. Nabors Oil & Gas Co.*, 97 So. 666 (La. 1923), but a mineral servitude is somewhat analogous to a severed mineral estate.

subsurface of the land where the minerals are found. Indeed, the mineral servitude owner does not even own subsurface minerals while they remain naturally in place underground. Therefore, it would make little sense to conclude that the empty space from which minerals are removed belongs to the servitude owner. Instead, the landowner owns that space. Accordingly, the landowners in *43.42 Acres*, not the mineral servitude owner, were entitled to compensation for the value of using the subsurface salt dome cavern for storage.

In *Lightning Oil Co. v. Anadarko E&P Onshore*, 520 S.W.3d 39, 46 (Tex. 2017), a surface estate owner (landowner) and mineral estate owner fought over who had the right to authorize drilling through the subsurface, in circumstances where the drilling was not for the purpose of recovering oil or gas from beneath the land. The Court concluded that the owner of the surface estate, rather than the mineral owner, had this right. In resolving that case, the Texas Supreme Court suggested that the owner of the surface estate owned everything in the subsurface other than minerals. And more recently, in deciding whether the mineral owner or the owner of the surface estate had the right to use salt dome caverns for storage, the Texas Supreme Court stated that this right belonged to the surface estate because empty space in the subsurface belongs to the owner of the surface estate, not the mineral owner.⁴⁸

In a dispute over injection disposal of saltwater, the North Dakota Supreme Court stated in *Mosser v. Denbury Resources, Inc.*, 898 N.W.2d 406, 412 (N.D. 2017) that “the owner of a surface estate owns the underlying pore space absent a conveyance of the pore space to a third party.” And, in *Northwest Landowners Association v. State*, 978 N.W.2d 679, 690 (N.D. 2022), the North Dakota Supreme Court repeated its statement that subsurface pore spaces are part of the surface estate and thus belong to the landowner.

III. Compensating landowners for pore space rights

To acquire pore space rights beneath a particular tract of land, the CCS operator will typically have to compensate the landowner. The method of compensation may depend on how the CCS operator obtains pore space rights. A prospective CCS operator may acquire pore space rights by agreement with a landowner, paying to the landowner whatever compensation contemplated by the agreement. Alternatively, in several states, the law provides a means by which a CCS operator could acquire the right to use subsurface pore spaces, even if the landowner has not granted consent, subject to an obligation for the CCS operator to pay compensation for the rights obtained.

A. Compensation when CCS operator obtains pore space rights by consent

One of the ways that a CCS operator can obtain pore space rights is by agreement with the landowner. Several different types of agreement could be used—(1) subsurface leases are perhaps the most common type of agreement for acquiring pore space rights, (2), servitudes (or, in states other than Louisiana, an easement), which may be the second most common way of acquiring pore space rights, and (3) various other types of agreements. Each of these is discussed below.

1. Compensation when leases are used to acquire pore space rights

Of the various types of contracts that could be used by a CCS operator to acquire pore space rights, the type that the authors of this White Paper have seen most often is a lease of pore space rights. A “lease” is a “[bilateral] contract by which one party, the lessor, binds himself to give to the other party, the lessee,

⁴⁸ *Myers-Woodward, LLC v. Underground Services Markham, LLC*, 716 S.W.3d 461, 868 (Tex. 2025).

the use and enjoyment of a thing for a term in exchange for a rent that the lessee binds himself to pay.”⁴⁹ Rent typically consists of money, though the parties can agree to other forms of compensation.⁵⁰

Often, rent is paid in a series of periodic payments, such as monthly payments or perhaps annual payments when there is a multi-year lease, but the rent can be paid in a single upfront payment, or both an upfront payment and periodic payments, or any other arrangement to which the parties agree. The amount of rent to be paid must be determinable, but it need not be a fixed amount.⁵¹ Thus, the rent for a mineral lease can be based on the value of the minerals extracted, the rent for a farming lease can be based on the amount or value of crops harvested, and the rent for a commercial lease could be based on the revenue that the leaseholder commercial operations obtains. Analogously, the rent for a CCS lease could be based on the amount of CO₂ injected, which in turn can be translated into a certain dollar value of CCS tax credits.

With CCS, the plan is to leave the injected CO₂ in place permanently. Under Louisiana law, the maximum term of a lease is ninety-nine years,⁵² but this need not preclude the use of a lease for granting pore space rights for CCS. Civil Code article 2683 requires the leaseholder to use the leased premises “as a prudent administrator and in accordance with the purpose for which it was leased.”⁵³ Given that the purpose of a pore space lease for CCS would be to inject CO₂, doing so would not violate this Civil Code article 2683 obligation. Article 2683 also requires the leaseholder, at the end of the lease, to return the leased premises to the lessor “in a condition that is the same as it was when the thing was delivered to him, except for normal wear and tear,” but the Louisiana Supreme Court has held that the natural result of activities expressly authorized by the lease qualify as normal wear and tear.⁵⁴ The default rule under Civil Code article 2695 is that, after the lease has terminated, the lessor can demand that the leaseholder remove items that it placed on the lease, but Article 2695 itself recognizes that this only applies in the absence of contrary agreement, and likely is (or should be) understood by the parties to a CCS lease that the intent is to leave the CO₂ in place permanently. Further, the mere fact that a lease has terminated does not mean that items that the leaseholder placed on the leased premises become the property of the lessor.

There are several publicly available examples of pore space leases for CCS. For example, as of August of 2025, the State of Louisiana has granted six pore space leases, and these are available on the Department of Energy and Natural Resources website.⁵⁵ The State of Texas also has granted multiple leases for the use of pore spaces in CCS operations. These are available from the Texas General Land Office by public records requests. Further, the State of Wyoming has granted such leases.

Most of these leases provide for an upfront payment of a specified amount, periodic payments that are based directly or indirectly on the amount of CO₂ injected, and certain other payments.⁵⁶ For example, the first few of the leases granted by the State of Louisiana provided for an upfront payment, annual

⁴⁹ La. Civ. Code art. 2668 (defining lease); see also La. Civ. Code art. 1908 (equating “bilateral” and “synallagmatic,” the latter of which is a term used in the Civil Code’s definition of “lease”). This is the definition under Louisiana law. The term “lease” is used similarly outside Louisiana. Black’s Law Dictionary states: “A contract by which a rightful possessor of real property conveys the right to use and occupy the property in exchange for consideration, usu. rent.” Black’s Law Dictionary (12th ed. 2024).

⁵⁰ La. Civ. Code art. 2675 (“The rent may consist of money, commodities, fruits, services, or other performances sufficient to support an onerous contract.”). Black’s Law Dictionary’s definition of “lease” refers to the leaseholder giving “consideration.” Black’s Law Dictionary (12th ed. 2024).

⁵¹ La. Civ. Code art. 2676.

⁵² La. Civ. Code art. 2679.

⁵³ La. Civ. Code art. 2683.

⁵⁴ Terrebonne Parish School Bd. v. Castex Energy, Inc., 893 So. 2d 789 (La. 2005).

⁵⁵ Copies of these are available on the Louisiana Department of Energy and Natural Resources (DENR) website at <https://www.dnr.louisiana.gov/page/carbon-capture-and-wind-energy-agreements>. The six leases are called “operating agreements,” based on the statutory authority that the State Energy & Mineral Board (which is under DENR) relied upon in granting the agreements, but substantively the agreements are leases.

⁵⁶ Note that a company that is able to avoid or “abate” CO₂ emission through CCS might be eligible for the 45Q federal tax incentive, which is based on the tons of CO₂ injected. The 45Q tax credit is likely to be the largest source of revenue for CCS projects under current conditions. Other potential sources of revenue include the firm’s ability to sell low carbon intensity products to the market for a premium, selling credits onto voluntary carbon markets, and perhaps avoid carbon border adjustment mechanisms such as the European Union’s CBAM. The companies doing CCS will have to pay for the capture, transportation, and storage of the CO₂.

payments in a fixed amount per acre until injections of CO₂ begin, and periodic injection fees based on the tons of CO₂ injected thereafter. The later leases granted by the State of Louisiana similarly provided for an upfront payment, fixed annual rentals, and a per-ton injection fee, but instead of providing that the fixed annual fees would stop when injections and injection payments began, the later leases provided that the fixed annual payments would continue until the operator's injection rights end.⁵⁷

The first lease granted by the State of Texas provided for an upfront payment, additional lump sum payments when and if the leaseholder's project reached certain milestones, and periodic payments based on the revenue received by leaseholder for the CCS operation. Given that the largest source of revenue for a CCS operation in the U.S. typically will be the 45Q federal tax incentive, which is based on the tons of CO₂ injected, and that at least some of the other sources of revenue, such as voluntary carbon markets, likely are based on the amount of CO₂ injected, the revenue-based fee is essentially a fee based on the amount of CO₂ injected. A lease granted by the State of Wyoming similarly provided for multiple bonus payments and a fee for the amount of CO₂ injected.⁵⁸ The Principal Investigators for this Study are aware of other pore space leases for CCS that are not publicly available that include compensation schemes similar in structure to the leases noted above.

It is notable that the amounts of compensation to be paid to the lessor varies substantially between some of the leases noted above. This does not necessarily mean that any of the parties involved in those leases negotiated a bad deal. The value of property for use in CCS depends on several factors. These might include (but are not limited to) the: proximity of the property to the carbon capture site or sites (the greater the distance from the capture site, the less valuable the storage site because it means that the CCS operator will have to construct a longer pipeline to transport captured CO₂ to the injection site); porosity of the storage reservoir (a greater percentage of pore space generally will mean more storage capacity per acre); permeability (greater permeability makes it easier to inject CO₂); number of existing and historic wells that penetrate the storage formation (because existing wells will need to be investigated and, in some cases, corrective action will have to be taken to ensure that the existing wells do not provide a pathway for leakage of CO₂, the fewer the number of penetrations the better); size of the property (larger is better because it can reduce transaction costs per acre); total pore space volume available; the number of alternative locations for conducting CCS in the area; and the regulatory environment.⁵⁹

2. Compensation when servitudes are used to acquire pore space rights for CCS

A second type of agreement that has been used to grant pore space rights for CCS is a type of grant that is called a ***servitude*** in Louisiana, and would be called an "easement" in most other states.⁶⁰ A servitude

⁵⁷ For example, consider the State's CCS pore space agreement with Castex Carbon Solutions, LLC. Under it, the "Operational Term" begins when the operator begins injections of carbon dioxide, assuming the agreement has not already terminated because of the operator's failure to meet deadlines specified in the agreement for making certain progress on the CCS project. The operator has a right to make injections during the Operational Term, which continues until there is a 12-month period in which the operator does not inject any carbon dioxide. After that, if the operator requests it, the State has discretion to grant one or more "Operational Discretionary Terms." If an "Operational Discretionary Term" is granted, the operator will have a right to make injections during that term, which will continue until there is another 12-month period in which the operator makes no injections. Article 4.2 of the agreement requires the operator to pay the State \$60 per acre per year during the Operational Term and also during any Operational Discretionary Terms. After that, the operator's duty to make annual rental payments ceases, as does its right to inject carbon dioxide, though the operator continues to have certain incidental rights, such as the right to conduct any legally required monitoring for carbon dioxide.

⁵⁸ This refers to a lease granted to Tallgrass High Plains Carbon Storage, LLC in 2023.

⁵⁹ These factors help determine how well suited the property is for CCS from the CCS operator's perspective. But the market price for pore space rights may also depend on any costs, including opportunity costs, that the landowner incurs due to a CCS project. After all, a rational landowner will not wish to grant pore rights to a CCS operator if, by doing so, the landowner will incur costs that exceed the benefits received by the landowner under the pore space agreement. For the most part, a CCS operator's use of pore spaces deep beneath the surface of a tract will not impose any direct costs on the tract owner and will not limit the tract owner's use of the land. However, if the landowner or anyone else holding mineral rights should wish to drill an oil and gas well to a formation beneath the formation in which the CCS operator is storing CO₂, the need to drill through the formation containing CO₂ will increase the costs of drilling because the oil and gas operator would need to use corrosion-resistant alloys for drilling through the formation containing carbon dioxide. This is because the subsurface typically will contain water, and the combination of carbon dioxide in water is slightly acidic.

⁶⁰ "The Louisiana concept of a servitude is equivalent to the common law concept of an easement." *Morgan City Land and Fur Co., L.L.C. v. Tennessee Gas Pipeline Co., L.L.C.*, 319 So. 2d 437 (La. 4th Cir. 2021); see also *Poule D'Eau Properties, L.L.C. v. TLC Properties, Inc.*, 367 So. 3d 764, 766-7 n.2 (La. App. 1st Cir. 2023) ("Under Louisiana jurisprudence, the common law word 'easement' is the same as the Louisiana 'servitude.'"). Black's Law Dictionary defines "easement" as "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)." Black's Law Dictionary (12th ed. 2024).

is a “charge on a thing” for the benefit of someone other than the owner of the thing.⁶¹ For example, a servitude can give a person the right to use, in a particular way, land owned by someone else.⁶² Thus, a landowner could grant someone else a servitude or easement allowing that person to use the pore spaces beneath the land for CCS.

In other states, an easement generally can be permanent. In Louisiana, a servitude need not have a term, and it can last indefinitely, but generally it will terminate by prescription of nonuse if there ever is a period of ten consecutive years in which the servitude is not used,⁶³ and parties generally cannot contract around this rule in advance. Thus, if a servitude is to be used to grant rights for storing CO₂ for CCS, the parties probably should characterize the servitude as being for the long-term storage of CO₂, as opposed to the disposal or the injection of CO₂. Otherwise, a court might hold that the servitude had terminated by prescription of nonuse ten years after injections ceased, even though the storage is intended to be permanent and even though the CCS operator’s regulatory obligation to monitor the CO₂ plume, and to monitor the storage area for potential leaks, may last for fifty years after injections of CO₂ cease.⁶⁴

A servitude can be created by an act of sale, by a reservation in favor of the seller, or by the owner of land granting a servitude in favor of someone else. In the case of a subsurface storage servitude for CCS, the servitude probably would be created by an owner of land granting the servitude in exchange for compensation. Although nothing would prohibit parties from agreeing for the price of a servitude to be paid in installments, or for the price to be based on the quantity of CO₂ injected, it probably is more common for servitudes to be “sold” for a fixed price, payable upfront in one installment.

3. Other types of agreements and the compensation under them

A CCS operator could purchase land outright for the area where the CO₂ plume will spread, but the CCS operator does not need the full set of rights that come with ownership of land for that entire area. For example, for most of that area where the CCS operator will need subsurface storage rights, the CCS operator will not need the right to use the surface of the land. Indeed, the CCS operator will not need rights to shallower portions of the subsurface, nearer to the surface than the storage formation and the containment zone that sits above the storage formation. Further, an outright purchase of the land generally would be more expensive than an acquisition of pore space rights. Thus, just as oil and gas companies seldom seek to purchase outright the land where they wish to explore for oil and gas,⁶⁵ CCS operators probably will seldom seek to purchase all the land where the CO₂ plume will spread. If, however, a CCS operator seeks to purchase the land outright in a voluntary sale, the purchase would be much like any other purchase of land.

In some states, a landowner and CCS operator might enter an agreement in which the CCS operator purchases ownership of the subsurface, not ownership of the surface. One of the authors of this White Paper has heard reports of such agreements, but has not seen the agreements themselves, and such agreements do not appear to be a very common way of a CCS operator obtaining pore space rights. Notably, such a horizontal severance of ownership, with one person owning the surface and someone else owning the subsurface, would not be allowed under Louisiana law.

⁶¹ La. Civ. Code arts. 524, 646.

⁶² See, e.g., La. Civ. Code art. 639.

⁶³ La. Civ. Code arts. 645, 753.

⁶⁴ The Safe Drinking Water Act regulations that govern the injection of CO₂ for CCS contemplate a default monitoring period of fifty years after injections cease, though this can be shortened.

⁶⁵ Most oil and gas operators acquire oil and gas leases, rather than purchasing the land outright.

B. Obtaining pore space rights in the absence of agreement

Within a porous, permeable formation into which CO₂ is injected, the CO₂ will migrate laterally, but it will not spread laterally forever. The lateral movement will be limited by dissipation of the CO₂ concentration as it migrates or by the CO₂ encountering impermeable barriers. However, within the portion of the storage formation where the CO₂ plume would tend to spread, the CCS operator will not be able to successfully cause the spreading plume to bypass the subsurface of any “holdout” or “non-consenting” landowner who declines to enter an agreement allowing the CCS operator to use the subsurface of the holdout landowner’s property. Accordingly, even if a CCS operator can obtain pore space rights for most of an area through voluntary agreement, a single holdout landowner could block a CCS project, unless the law provides some means for the operator to acquire pore space rights from non-consenting landowners. A holdout landowner’s ability to block a CCS project (absent some means for acquiring rights from the holdouts) is similar to the situation in which a holdout landowner could block a pipeline or electrical transmission line, except that a pipeline or transmission line could be routed around a holdout landowner’s tract, whereas a CCS operator would not have the same ability to force a plume of CO₂ molecules to be routed around a holdout tract. In contexts other than CCS, the law provides at least two types of processes that govern the subsurface property rights of neighboring landowners, and which could be used, in the CCS context, for acquiring pore space rights from non-consenting landowners—(1) eminent domain, and (2) pooling or unitization.⁶⁶

1. Eminent domain

One of the viable methods for giving CCS operators the ability to acquire subsurface pore spaces beneath the land of holdout landowners is eminent domain. Eminent domain is power of a governmental entity to take privately owned property for a public use, subject to the requirement that the governmental entity pay reasonable compensation for the property taken.⁶⁷ This authority can be delegated to private entities that provide services that are in the public interest. It is commonly used to acquire land or rights-of-way for highways, electric transmission lines, and pipelines.

a. Compensation under eminent domain

When eminent domain is used, the entity that utilizes eminent domain acquires a property right—typically, either ownership or a servitude (easement). In such cases, both the U.S. and Louisiana Constitutions require the entity that acquires the property interest to pay “just compensation” for the right acquired⁶⁸ and, under Louisiana law, the entity must compensate for the “full extent of [the] loss” to the person from whom the right was acquired.⁶⁹

The United States Supreme Court has stated that “just compensation,” as used in the U.S. Constitution, “means the full monetary equivalent of the property taken.”⁷⁰ Similarly, the rule under the Louisiana Constitution of 1921, was that the owner was entitled to “just and adequate compensation,” and this was interpreted as requiring the party using eminent domain to pay the market value of the property acquired.⁷¹ However, in 1974, the Louisiana Constitution was amended to provide that the owner was entitled to just compensation to the full extent of his loss, and this was intended to provide greater protection to property

⁶⁶ Pooling and unitization are concepts that come from oil and gas conservation law. Pooling and unitization are separate and distinct concepts, though they share some similarities and often are confused. Keith B. Hall and Hannah J. Wiseman, HYDRAULIC FRACTURING: A GUIDE TO ENVIRONMENTAL AND REAL PROPERTY ISSUES 263 (American Bar Association 2017) (“Although the terms ‘pooling’ and ‘unitization’ often are used interchangeably, prominent authorities give different meanings to the two terms.”).

⁶⁷ Black’s Law Dictionary (11th edition 2019).

⁶⁸ U.S. Const. amend. V; La. Const. art. I sec. 4.

⁶⁹ La. Const. art. I, sec. 4.

⁷⁰ U.S. v. Reynolds, 90 S. Ct. 803, 805 (1970).

⁷¹ Louisiana v. Rapier, 164 So. 2d 280, 282 (La. 1964).

owners, based on a feeling by the proponents of the amendment that compensation awards had not always compensated the owner for the full loss.⁷² In addition, it has long been the case that, when the entirety of a person's property is not taken, such as when the entity using eminent domain use it to acquire a right-of-way or use it to acquire full ownership of just a portion of a tract, the Louisiana Supreme Court and lower courts have recognized that the required compensation should account for any diminution in value of the property remaining to the landowner, such as the land burdened by the right-of-way.⁷³

b. Experience with eminent domain for pipeline and subsurface storage

In most jurisdictions, the law gives companies the right to use eminent domain for certain types of privately owned projects deemed to be in the public interest. For example, in many jurisdictions, pipeline companies can use eminent domain to acquire surface and subsurface easements to construct and operate pipelines for certain purposes,⁷⁴ and electric utilities can use eminent domain to acquire easements for electricity transmission and distribution lines.⁷⁵

Further, federal law, and the laws of some states, give private companies the right to use eminent domain to acquire subsurface storage rights for certain types of projects. For example, under the federal Natural Gas Act, companies that obtain a "certificate of public convenience and necessity" from the Federal Energy Regulatory Commission may use eminent domain to obtain subsurface storage rights.⁷⁶ In addition, several states have their own statutes that authorize natural gas companies to acquire subsurface storage rights via eminent domain.⁷⁷ A few of these states authorize the use of eminent domain to acquire subsurface storage rights for other fluids. Indeed, at least two states already have enacted legislation providing that, if a company obtains regulatory approval for a proposed CCS project, the company may use eminent domain to acquire subsurface storage rights it needs for its CCS project.⁷⁸

Generally, a right to use eminent domain can only be established by statute. A statute giving CCS operators a right to acquire pore space rights by eminent domain would have at least two salutary purposes. First, it would establish a way for a CCS operator to definitely acquire subsurface storage rights. Second, because the CCS operator would be "taking" a property interest from the landowner, compensation would be required. Except for the jurisdictions (if any) in which it is very clear that a landowner would not have a subsurface trespass claim for the migration of carbon dioxide, companies likely would gladly use eminent domain statutes to acquire pore space rights from landowners with whom the company could not reach a voluntary agreement for the acquisition of pore space rights.⁷⁹ However, if there was a

⁷² *Exxon Pipeline Co. v. Hill*, 788 So. 2d 1154, 1159 (La. 2001).

⁷³ *Louisiana v. Bitterwolf*, 415 So. 2d 196, 200 (La. 1982).

⁷⁴ See, e.g., 15 U.S.C. § 717(f)(h); Cal. Pub. Util. Code §§ 221 & 613; La. Rev. Stat. 19:2; Tex. Nat. Res. Code §§ 111.019 (common carriers have power of eminent domain) and 111.002 (stating which companies are common carriers).

⁷⁵ See, e.g., La. Rev. Stat. 19:2(7); Tex. Util. Code § 181.004.

⁷⁶ 15 U.S.C. § 717(f)(h). This statute grants the right to acquire rights necessary for pipelines. Although the statute does not expressly refer to the right to obtain subsurface storage rights, the statute consistently has been interpreted as authorizing the acquisition of subsurface storage rights via eminent domain. See, e.g., *Columbia Gas Transmission Corp. v. Exclusive Gas Storage Easement*, 776 F.2d 125, 128 (6th Cir. 1985); *Mississippi River Transmission v. Tabor*, 757 F.2d 662, 666 n.5 (5th Cir. 1985); *National Fuel Gas Supply Corp. v. 138 Acres of Land*, 84 F. Supp. 2d 405, 410 (W.D. N.Y. 2000); *Transcontinental Gas Pipe Line Corp. v. 118 Acres of Land*, 745 F. Supp. 366 (E.D. La. 1990); *Columbia Gas Transmission Corp. v. An Exclusive Gas Storage Easement*, 705 F. Supp. 1242 (N.D. Ohio 1988); *Natural Gas Pipeline Co. v. Iowa State Commerce Comm'n*, 369 F. Supp. 156, 158 (S.D. Iowa 1974). Cf. *Schneidewinde v. ANR Pipeline Co.*, 485 U.S. 293, 295 n.1 (1988) (underground natural gas storage is part of "transportation").

In several places, companies store natural gas in the subsurface, near markets for the consumption of natural. During times of the year when demand for natural gas is (and thus excess pipeline capacity is available), a company can move natural gas from the fields where it is produced to subsurface storage locations near areas where large amounts of natural gas are consumed (such as large population centers) for easy delivery during other times of the year when demand is high (such as during the winter).

⁷⁷ See, e.g., Ala. Code § 9-17-154; Ark. Code § 15-72-604; Cal. Pub. Util. Code §§ 221 & 613; Colo. Rev. Stat. § 34-64-103 & 106; Ga. Code § 46-4-57; Ill. Comp. Stat. 15/1, 15/2, and 15/6; Ind. Code § 32-24-5-2 & § 32-24-5-5; Iowa Code § 479.24; Kan. Stat. 55-1203; Ky. Rev. Stat. § 278.502; La. Rev. Stat. 19:2; Md. Code, Env't § 14-202; Mich. Comp. Laws § 486.251 & 486.252 & 486.254; Miss. Code § 53-3-159; Mo. Stat. § 393.430; Mont. Code § 82-10-303; Neb. Rev. Stat. § 57-603; N.M. Stat. § 70-6-7; N.Y. Env't Conserv. Law § 23-1303; Ohio Rev. Code § 1571.17 & § 1571.01; 52 Okl. Stat. Tit. 52 § 36.3; Or. Rev. Stat. § 520.350; Tenn. Code § 65-28-101; Tex. Nat. Res. Code § 91.179; Utah Code § 78B-6-501; Wash. Rev. Code § 80.40.030; W. Va. Code § 54-1-2.

⁷⁸ See Ala. Code § 9-17-154; La. Rev. Stat. 30:1108.

⁷⁹ Given the size of the investment needed for a CCS project, it would be foolhardy for a company to inject carbon dioxide without acquiring pore space rights, simply hoping that a court would conclude that the migration of carbon dioxide does not constitute an actionable trespass.

concern that CCS operators might not do so, a jurisdiction could use a statute, regulation, or conditions built into regulatory permits to impose a duty for CCS operators to pay for pore space rights.

Notably, and as discussed in more detail later in this White Paper, a few states have statutes that authorize prospective CCS operators to use eminent domain to acquire pore space rights. These states are Alabama,⁸⁰ Arkansas,⁸¹ and Louisiana (for projects in Caldwell Parish).⁸²

2. Pooling and unitization

An alternative to eminent domain exists. A state could adopt legislation authorizing a regulatory agency to use a method analogous to oil and gas pooling or unitization to grant CCS operators the right to use pore spaces beneath the properties of holdout landowners. Pooling and unitization are separate and distinct processes, though they share enough similarities that often they are conflated. Below, this White Paper discusses (a) what pooling and unitization are, (b) how compensation is allocated under pooling and unitization, and (c) the status of authorizing and using pooling- or unitization-like concepts for CCS.

a. What is pooling? What is unitization?

A basic explanation of pooling, followed by a basic explanation of unitization, is provided below.

i. What is pooling and what experience do we have with it?

A well drilled to a conventional formation containing oil or gas will efficiently drain (extract) the oil or gas from some area around the well. The size of the area that is efficiently drained by the well will depend on several factors. Spacing rules are a type of conservation provision that traditionally sought to avoid the drilling of unnecessary wells (and thus avoid the waste of capital) by creating drilling units equal in size to an area that could be efficiently drained by one well and allowing only one well to be drilled within the drilling unit. “Pooling” is a process for dealing with situations in which separately owned tracts are smaller than area that can be efficiently drained by a single well.

A prominent oil and gas treatise describes “pooling” as “the bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules.”⁸³ The “bringing together” of the small tracts means the tracts are all put within a single drilling unit. The agreement or regulatory order that does this will generally designate an “operator” that is permitted to drill a well for the unit, and all other owners of land within the unit are prohibited from drilling. However, the costs and revenue of the unit well are generally share amongst the owners of the tracts within the unit.⁸⁴ Pooling can be implemented by private agreement. In addition, most states authorize their oil and gas regulatory agencies to enter orders that create drilling units and implement pooling, and in some states (such as Louisiana), it is more common for pooling to be implemented by order of the regulator than by agreement.⁸⁵ The terms “statutory pooling” and “forced pooling” are sometimes used to refer to pooling that is implemented by a regulator’s order.

⁸⁰ Ala. Code § 9-17-154.

⁸¹ Ark. Code §§ 15-17-602, 15-17-604.

⁸² La. Rev. Stat. 31:1108.

⁸³ Patrick H. Martin and Bruce M. Kramer, 8 WILLIAMS & MEYERS, OIL AND GAS LAW (LEXISNEXIS 2024); see also Bruce M. Kramer and Patrick H. Martin, THE LAW OF POOLING AND UNITIZATION § 1.02 (LexisNexis) (stating that this publication will use “pooling” to “describe the joining together of small tracts or portions of tracts for the purpose of having sufficient acreage to receive a well drilling permit under the relevant state or local spacing laws and regulations, and for the purpose of sharing production by interest owners in such a pooled unit”); Bruce M. Kramer and Patrick H. Martin, THE LAW OF POOLING AND UNITIZATION § 6.01 (LexisNexis).

⁸⁴ Pooling can also have the effect of authorizing the operator to conduct activities in the subsurface (and perhaps on the surface) of any tract in the unit, as reasonably necessary to explore for and produce oil and gas. *Nunez v. Wainoco Oil & Gas Co.*, 488 So. 2d 955 (La. 1986); *Continental Resources, Inc. v. Farrar Oil Co.*, 559 N.W.2d 841, 846 (N.D. 1997). *Cf. Railroad Commission v. Manziel*, 361 S.W.2d 560, 568 (Tex. 1962) (normal rules of trespass altered when oil and gas regulator authorized a secondary recovery operation that might result in intrusion of injected water into subsurface of appellees’ land).

⁸⁵ This is also sometimes called “forced pooling.” See, e.g., *Ammonite Oil & Gas Corp. v. Railroad Commission*, 698 S.W.3d 198, 202 (Tex. 2024).

The traditional role of pooling has been as a method to address problems associated with the rule of capture, a rule that was recognized as law in Louisiana and under the common law of other states that have oil and gas activity in the U.S. early in the history of oil and gas development, before spacing rules were enacted.⁸⁶ Under the rule of capture, a landowner has the right to all the oil and gas produced from operations on and beneath his property, even if a portion of the oil and gas is “drained” from beneath the land of neighbors.⁸⁷ A neighbor’s only remedy (absent pooling) is the self-help remedy of drilling her own well.⁸⁸ But this has potential problems.

First, if the neighbor drills such an “offset well,” that could mean that two wells are drilled in an area that could be efficiently drained by one well. Because drilling a well is expensive, this is economically inefficient.⁸⁹ Further, the neighbors might not limit themselves to one well each. They may each drill multiple wells along the property line, racing to produce oil or gas from the common reservoir before the other does.

Second, in some types of formations, such as a “water-drive field,” a greater ultimate recovery of oil can be achieved by extracting oil at a moderate pace, rather than at too rapid a pace. When oil is extracted too quickly, subsurface water that lies beneath the oil can intrude into the pool of oil, bypassing pockets of oil that then become difficult to recover in an economic manner. Further, some people would argue that the effect of the rule of capture is unfair, and thus fairness is arguably a third problem associated with the rule of capture.

Neighbors could enter voluntary pooling arrangements in which they agree to conduct joint operations, and sometimes this happens. But often it is difficult or impossible to obtain agreement of all the parties, and early in the history of the oil and gas industry the drilling of more wells than was reasonably necessary continued long after the problems associated with the rule of capture became well understood. Accordingly, states began to enact conservation statutes that gave their oil and gas regulatory agencies the various powers to curb wasteful and inefficient practices.

One of these powers was the authority to create drilling units that would include neighboring tracts, each of which was too small to justify its own oil and gas well under spacing rules, but which collectively were large enough to justify a well. An order creating a drilling unit would typically authorize one of the owners (often called the “operator”) to drill, but no other owner would be allowed to drill. And, assuming the owners of the separate tracts within the drilling unit had not already entered a voluntary pooling agreement, the regulator would have authority to issue an order “pooling” all the separately owned tracts, thereby requiring a sharing of the operator’s revenue (and costs) between the tracts in the drilling unit.

⁸⁶ The rule of capture seems to apply in all jurisdictions that have addressed drainage disputes between neighboring lands. See Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS, OIL AND GAS LAW § 204 (“The so-called Rule of Capture appears equally applicable in all states. ...”). See, e.g., NCNB Texas Nat. Bank, N.A. v. West, 631 So. 2d 212, 224 (Ala. 1993) (referring to rules of capture with apparent approval); Osborn v. Arkansas Territorial Oil & Gas Co., 146 S.W. 122, 124 (Ark. 1912); Continental Resources, Inc. v. Illinois Methane, LLC, 847 N.E.2d 897, 901 (Ill. Ct. App. 2006); Zinc Co. v. Freeman, 75 P. 995, 997 (Kan. 1904); La. Rev. Stat. 31:14; Michigan Consol. Gas Co. v. Muzeck, 145 N.W.2d 266, 269-70 (Mich. Ct. App. 1966) (“This fundamental precept of oil and gas law, commonly known as the ‘law of capture’, is based upon the fugitive nature of oil and gas, and has been uniformly adopted throughout the United States.”); California Co. v. Britt, 154 So. 2d 144, 147 (Miss. 1963); Baumgartner v. Gulf Oil Corp., 168 N.W.2d 510, 515 (Neb. 1969); Kelly v. Ohio Oil, 49 N.E. 399 (Ohio 1897); Atlantic Richfield v. Tomlinson, 859 P.2d 1088, 1094-5 (Okla. 1993); Briggs v. Southwestern Energy Production Co., 224 A.3d 334, 336 (Pa. 2020); Coastal Oil & Gas Corp. v. Garza Energy Trust, 268 S.W.3d 1, 13 (Tex. 2008); Cowling v. Bd. of Oil, Gas & Mining, 830 P.2d 220, 224 (Utah 1991); Energy Development Corp. v. Moss, 591 S.E.2d 135, 146 (W. Va. 2003).

⁸⁷ For convenience, this White Paper refers to the landowner as the person who has the right to explore for and produce oil and gas from the land or to grant someone else an oil and gas lease that gives the lessee the right to explore for and produce oil and gas. Sometimes, however, the landowner or a former owner of the land will have severed this right from the land by granting a mineral servitude (in Louisiana) or creating a severed mineral estate in some other jurisdiction. In such a case, the mineral servitude holder or the owner of the severed mineral estate generally will be the person who has a right to explore for and produce oil from the land or grant an oil and gas lease to someone else.

⁸⁸ A well drilled in response to a neighbor’s productive well in an effort to prevent drainage is sometimes called an “offset well.” General American Oil Co. v. Superior Oil Co., 416 So. 2d 251, 257 (La. App. 3rd Cir. 1982); Millette v. Phillips Petroleum Co., 48 So. 2d 344, 347 (Miss. 1950); Texas Pacific Coal & Oil Co. v. Barker, 6 S.W.2d 1031, 1033 (Tex. 1928). Sometimes courts or commentators, particularly in times past, referred to the drilling of offset wells as “protecting the lines.” Rogers v. Heston Oil Co., 735 P.2d 542, 548 (Okla. 1984); Barnard v. Monongahela Natural Gas Co., 65 A. 801, 802 (Pa. 1907); Harness v. Eastern Oil Co., 38 S.E. 662, 664 (W. Va. 1901); Kelly v. Ohio Oil Co., 49 N.E. 399, 399 (Ohio 1897).

⁸⁹ The waste of capital inherent in drilling more wells than needed to efficiently drain an area has traditionally been the main public policy motivation for regulations that seek to avoid the drilling of unnecessary wells. However, drilling multiple wells also increases the impact on the environment. The environmental impact may not be very pronounced in areas that already have been developed for industry or agriculture, but in undeveloped areas, the drilling of multiple wells can increase the impact on wildlife habitat.

Almost all states with oil and gas activity—and some that do not have oil and gas activity—have statutes that authorize a regulator to issue pooling orders.⁹⁰ The only exception is Kansas, which has oil and gas activity, but no state law authorizing compulsory pooling. It should be noted, however, that, in some states that authorize a regulator to order pooling, the statutory authority is seldom used because of restrictions on the regulator’s pooling authority. For example, Texas has a Mineral Interest Pooling Act, which authorizes the Texas Railroad Commission (the regulator of oil and gas activity in Texas) to issue pooling orders upon application of a party with an interest in the proposed drilling unit,⁹¹ but parties find it difficult to satisfy the requirements contained in the statute. Accordingly, oil and gas leaseholders often seek to use voluntary units or other workarounds, rather than relying on the Texas’s Mineral Interest Pooling Act.⁹²

Another example is Pennsylvania. Pennsylvania has a pooling statute,⁹³ but it only applies to formations deeper than the Onondaga formation,⁹⁴ and most oil and gas activity in Pennsylvania takes place in shallower formations. Accordingly, oil and gas operators typically rely on voluntary pooling or other workarounds.⁹⁵

Traditionally, a drilling unit was supposed to be the maximum area that could be efficiently drained by one well,⁹⁶ and generally the regulator would only allow one well to be drilled in the unit. Drilling units and pooling orders will cover a particular area, and often they apply only to a particular formation or to specified depths beneath the surface, not to all formations or all depths. After all, a well drilled and completed only to a particular formation generally will not drain oil or gas from deeper or shallower formations. Further, appropriate size of a unit may vary from one formation to another because the area that a well can efficiently drain can vary from one formation to another.

Many state statutes that authorized a regulator to issue orders for drilling units and pooling stated that the purpose of such orders should be to (1) prevent waste, such as the waste that can result if the overly rapid production of oil that causes the drainage pattern to bypass some pockets of oil that might never be recovered, (2) avoid the drilling of unnecessary wells, by which the law means the drilling of more wells than are needed to efficiently drain an area, and (3) protect correlative rights, which means the opportunity of all persons owning land above a common pool of oil or gas to recover his or her share of those hydrocarbons. In most states, the regulator can issue drilling unit and pooling orders either on its own initiative or upon application of a party, with it being more common for orders to be issued after application of a party. Most statutes authorizing drilling units and pooling do not require that any particular fraction of the landowners in a proposed unit support pooling before the regulator has authority to issue a pooling. The regulator merely has to be persuaded that the proposed pooling will satisfy certain statutory prerequisites—typically that it will prevent waste, avoid the drilling of unnecessary wells, and protect correlative rights.

⁹⁰ See e.g., Ala. Code § 9-17-13; Alaska Stat. § 31.05.100(c); Ariz. Rev. Stat. § 27-505; Ark. Code § 15-72-302; Colo. Rev. Stat. § 34-60-116(6); Fla. Stat. § 377.27; Idaho Code § 47-320; Ky. Rev. Stat. § 353.630; La. Rev. Stat. 30:9 and 30:10; N.M. Stat. § 70-2-17(C); Okla. Stat. 52 § 87.1(e); Tex. Nat. Res. Code §§ 102.001-.112; Utah Code § 40-6-6.5; Wyo. Stat. § 30-5-109(f).

⁹¹ Tex. Nat. Res. Code §§ 102.001-.112.

⁹² Often, the units are “declared units,” which are units created by a leaseholder that has leases covering neighboring tracts, and whose leases delegate to the leaseholder the authority to commit the leased premises to a pooled unit. *Humble Oil & Refining Co. v. Jones*, 125 So. 2d 640, 642 (La. App. 3rd Cir. 1960); see also Morris S. Gray and Hugh V. Schaefer, *Conflict Between Voluntary Pooling Agreements and State Spacing and Pooling Orders*, Proceedings of 27th Rocky Mtn. Min. L. Inst., Ch. 6 (1982). The other workarounds include production sharing agreements and allocation wells. Keith B. Hall, *Single Well Spacing and Pooling: State Spacing and Jurisdiction Over Conservation*, Rocky Mtn. Min. L. Fdn. Advanced Landman’s Inst. (2019).

⁹³ 58 P.S. § 408.

⁹⁴ 58 P.S. § 403(b).

⁹⁵ One workaround is contained in 58 P.S. § 34.1, which states: “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.”

⁹⁶ This was the traditional language of Louisiana Revised Statute 30:9 until the language was amended in 2015, by La. Acts 2015, No. 253, when it was amended to state that a drilling unit *should be* “the maximum area which may be efficiently and economically drained by the well or wells designated to serve the drilling unit.”

The creation of drilling units and the pooling of the separately owned interests in the unit work together, and in the remainder of this paragraph, as well as in some other portions of this White Paper, these two actions are collectively called “pooling.” Such pooling serves a different purpose than unitization, which is sometimes called “fieldwide unitization,” and which is discussed below. Further, in most or all states, the statutes that authorize a regulator to issue pooling orders are different statutes than those that authorize a regulator to enter orders for fieldwide unitization. And, the requirements that must be met for pooling usually are different than the requirements that must be met for fieldwide unitization.

ii. What is “unitization”?

A prominent oil and gas treatise describes unitization as the joint operation of all or some portion of a producing reservoir.⁹⁷ Unitization has some similarities to pooling.⁹⁸ For example, under unitization, a single company typically will be named operator and only it will be allowed to conduct operations in the unitized formation. Further, there will be a sharing of revenue and costs amongst the various tracts in the fieldwide unit.

However, whereas “pooling” traditionally has involved the aggregation of small tracts to form a drilling unit of sufficient size to justify the granting a single well permit,⁹⁹ and does not attempt to coordinate operations over a large area, fieldwide unitization is used to facilitate the coordinated operation of a large area, usually all or a substantial portion of a common formation of oil, and such an area may be served by numerous wells. The sort of fieldwide coordination that can be achieved with unitization theoretically could help increase production or lower costs during primary production,¹⁰⁰ but fieldwide unitization is not commonly used in the United States for primary production. Where it is used during primary production, it usually is in oil fields where pressure maintenance¹⁰¹ or gas injection¹⁰² are needed to avoid waste, or for primary production from a very deep formations that will involve very expensive and complex drilling

⁹⁷ Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 901.

⁹⁸ The terms “pooling” and “unitization” are sometimes used interchangeably—probably because the two concepts have some similarity—but oil and gas scholars and commentators generally take care to distinguish the two concepts. Keith B. Hall and Hannah J. Wiseman, HYDRAULIC FRACTURING: A GUIDE TO ENVIRONMENTAL AND REAL PROPERTY ISSUES 263 (American Bar Association 2017) (“Although the terms ‘pooling’ and ‘unitization’ often are used interchangeably, prominent authorities give different meanings to the two terms.”).

Further, the law recognizes a difference. The statutes that authorize the regulator to enter pooling orders are different from the statutes that authorize the regulator to enter unitization orders, and the requirements that must be met before a pooling order is authorized are different than the requirements needed to justify a unitization order. Compare, for example: La. Rev. Stats. 30:5 (unitization) on the one hand with 30:9 and 30:10 (pooling); N.M. Stats. §§ 70-2-17(B) (pooling) and 70-7-6 (unitization); 52 Okla. Stats. §§ 87.1(a) (pooling) and 287.4 (unitization); Wyo. Stat. § 30-5-109(f) (pooling) and Wyo. Stat. § 30-5-110 (unitization).

Texas is an exception to the rule that most states with oil and gas activity grant the oil and gas regulator the authority to order pooling, as well as the authority to order unitization. Texas authorizes its oil and gas regulator—the Texas Railroad Commission—to issue pooling orders, Tex. Nat. Res. Code §§ 102.001-.112, but does not authorize the regulator to order unitization. Bruce M. Kramer, *Principles and Historical Context of Pooling and Unitization*, Rocky Mountain Mineral Law Special Institute: Onshore Pooling and Unitization, Ch. 1 (1997) (“Today, with the exception of Texas, all major producing states have a compulsory unitization statute.”).

Moreover, oil and gas leases often delegate to the lessee the authority to agree to voluntary pooling, voluntary unitization, or both. Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW § 866 (“A substantial number of contemporary oil and gas leases contain a clause which authorizes the lessee under certain specified conditions to pool or unitize the leased premises with other premises.”).

⁹⁹ Patrick H. Martin and Bruce M. Kramer, MANUAL OF OIL AND GAS TERMS.

¹⁰⁰ In most oilfields, production begins with primary production. In primary production, oil flows to the surface without pumping (due to the pressure of the subsurface formation from which the oil is produced) or by being pumped. Over time, however, the rate at which oil can be produced via primary production declines and eventually it no longer is economical to continue producing oil via primary production because operating costs will exceed operating revenue. At this stage, the subsurface formation will still contain a portion of the crude oil that originally was there. The fraction of the original oil that remains in place when primary production is no longer economical will depend on several factors.

¹⁰¹ The term “pressure maintenance” refers to “[t]he injection of gas, water or other fluids into oil or gas reservoirs to maintain pressure or retard pressure decline in the reservoir for the purpose of increasing the recovery of oil or other hydrocarbons therefrom.” See Patrick H. Martin and Bruce M. Kramer, MANUAL OF OIL AND GAS TERMS.

Gas reinjection or pressure maintenance operations typically require fieldwide unitization (or a regulatory order requiring reinjection) because, when a large oilfield has several companies operating wells, one company’s decision to reinject gas to maintain pressure will not help maintain the pressure of the formation very well if most other operators are not reinjecting gas. Secondary recovery and enhanced recovery often require fieldwide unitization because they require conversion of some wells from being production wells to being injection wells, but no company will want to convert its wells from being production wells to being injection wells unless it is given a share of the production from other wells that continue to operate as production wells.

¹⁰² Gas injection is the “[i]ntroduction of gas under high pressure into a producing reservoir through an input or injection well as part of a [pressure maintenance, secondary recovery, or recycling operation.” See Patrick H. Martin and Bruce M. Kramer, MANUAL OF OIL AND GAS TERMS. The “Schlumberger Energy Glossary” defines “gas injection” as being “[a] reservoir maintenance or secondary recovery method that uses injected gas to supplement the pressure in an oil reservoir or field. In most cases, a field will incorporate a planned distribution of gas-injection wells to maintain reservoir pressure and effect an efficient sweep of recoverable liquids.” https://glossary.slb.com/en/terms/g/gas_injection.

operations.¹⁰³ Fieldwide unitization is more commonly used for secondary recovery¹⁰⁴ and enhanced oil recovery operations.¹⁰⁵

Like pooling, fieldwide unitization can be implemented by voluntary agreement,¹⁰⁶ but as with pooling, most oil and gas states also authorize a regulatory agency to enter orders that implement unitization.¹⁰⁷ But as already noted, fieldwide unitization and pooling serve different purposes, and the statutes that authorize fieldwide unitization are different than the statutes that authorize pooling. One notable difference between statutes that authorize pooling orders and statutes that authorize fieldwide unitization orders is that, in most states, the statutes that authorize a regulatory agency to enter pooling orders does not require that any particular fraction of landowners or mineral interest owners in a proposed drilling unit support the creation of the unit before a regulator can order pooling. In contrast, most unitization statutes require consent from a specified fraction of landowners and mineral interest owners before the regulator can order unitization.¹⁰⁸

Also, in pooling, the sharing of revenue is usually in proportion to the acreage in which each person has an interest. Thus, someone who held all mineral rights in a 20-acre tract would get twice the share of a person who held all mineral rights in a 10-acre tract. In unitization, however (as is discussed in more detail later), the formula for sharing often is more complex than a simple surface acreage basis.¹⁰⁹ The formula for sharing may consider acreage, as well several other factors. For example, if two persons each held all mineral interests in separate tracts of the same size, but the estimated vertical thickness of the oil formation beneath the first person's tract was fifty feet, while the estimated thickness beneath the second person's tract was one hundred feet, the second person might get twice the share of the first person.

¹⁰³Patrick H. Martin and Bruce M. Kramer, *MANUAL OF OIL AND GAS TERMS*. See, e.g., La. Rev. Stat. 30:5.1.

¹⁰⁴The "Schlumberger Energy Glossary" entry for "secondary recovery" states in part:

The second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir.

https://glossary.slb.com/en/terms/s/secondary_recovery. Another source states, that the term "secondary recovery" typically is used to refer to methods for the "recovery of hydrocarbons in which part of the energy employed to move the hydrocarbons through the reservoir is applied from extraneous sources by the injection of liquids or gases into the reservoir." See Patrick H. Martin and Bruce M. Kramer, *MANUAL OF OIL AND GAS TERMS*.

During secondary recovery, an operator often employs a combination of injection wells and production wells. The operator will use the injection wells to inject a substance such as water or steam into the formation that contains oil. The water or steam will help push or sweep the oil toward production wells, from which a combination of oil and the injected water are produced. The water is separated from the recovered oil and recycled to join the stream of water being injected. If the substance being injected is steam, it may also heat the oil and reduce its viscosity, making the oil flow more easily. Viscosity is a measure of a fluid's resistance to flowing. Cold molasses is an example of a fluid that has a high viscosity. If the molasses is heated, its viscosity or resistance to flowing will decrease.

¹⁰⁵The "Schlumberger Energy Glossary" entry for "enhanced oil recovery" states in part:

An oil recovery enhancement method using sophisticated techniques that alter the original properties of oil. Once ranked as a third stage of oil recovery that was carried out after secondary recovery, the techniques employed during enhanced oil recovery can actually be initiated at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide [CO₂] injection or hydrocarbon injection), and thermal recovery (steamflood or in-situ combustion).

https://glossary.slb.com/en/terms/e/enhanced_oil_recovery. Another source states that "enhanced recovery" is

[T]he increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of (i) aiding in the lifting of fluids in the well, or (ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

See Patrick H. Martin and Bruce M. Kramer, *MANUAL OF OIL AND GAS TERMS*.

During enhanced recovery (sometimes called tertiary recovery because it sometimes begins after secondary recovery cannot economically recover any more oil), a substance such as carbon dioxide is injected into the oil-bearing formation, using injection wells. The carbon dioxide can help push or sweep the oil toward production wells, but in addition the carbon dioxide can dissolve into the oil. This causes the oil to swell and become less viscous, thereby making the oil flow more easily.

¹⁰⁶Bruce M. Kramer and Patrick H. Martin, *THE LAW OF POOLING AND UNITIZATION* § 17.01.

¹⁰⁷*Id.* § 18.01 ("Every major producing state, other than Texas, has a compulsory unitization statute.").

¹⁰⁸*Id.* § 18.02[4][b] ("with the possible exception of Alaska and Washington, all of the compulsory unitization statutes require that the application for the order have the consent or approval of a minimum percentage of the working- and royalty-interest owners before the order is issued or becomes effective.") (footnotes omitted from quote).

¹⁰⁹Because unitization orders or agreements typically cover a larger area than pooling, there likely will be greater variation in an oil-bearing formation across the larger area covered by unitization than across the smaller area covered by pooling. Factors that can vary across a formation include formation thickness, porosity, permeability, and whether oil can still be economically recovered by primary production from a particular tract, even though it is no longer economic to do so from other tracts, and even though a transition to secondary recovery operations might be economically efficient when considering the formation as a whole. Further, it seldom is the case that there is a particular allocation formula that is obviously the fairest formula for allocation revenue between tracts. Thus, parties will each be tempted to argue for a proposed formula that maximizes their proportional allocations and against proposed formulas that would give them a smaller allocation.

b. Allocation of revenue and costs under pooling and unitization

Under both pooling and unitization, a specified fraction of unit revenue and generally the same fraction of unit costs will be allocated to each separately owned tract in the unit. There are two notable issues to resolve with respect to these allocations: (i) how to determine the fraction of unit revenue and costs to allocate to each tract, and (ii) how to deal with owners who do not wish to participate in the upfront costs and risks of an operation.

i. Determining the fraction of unit revenue and costs to allocate to each tract

Under pooling and unitization, the fraction of unit revenue allocated to each tract will be the same as the fraction of unit costs allocated to that tract. But how is the fraction for each tract determined? Experience with pooling and unitization offer examples: (aa) acreage-based allocations, and (bb) allocations based on both acreage and additional factors.

aa. Acreage-based allocations

Most pooling statutes do not specify a method of allocation. Instead, most of these statutes provide a general standard, stating something to the effect that the allocation must be “equitable.” However, the essentially universal practice of regulators is to base the allocation of revenue and costs for a pooled drilling unit on surface acreage alone.¹¹⁰ Under this method, if the portion of a particular tract that is within a unit makes up ten percent of the unit’s total area, then ten percent of the unit revenue and ten percent of the unit costs would be allocated to that tract. Thus, a sixty-four-acre tract would receive twice the allocation that a thirty-two-acre tract would receive, but only half the allocation that a 128-acre tract would.

There is much to be said in favor of this method. First, all other things being equal, a tract that is, for example, 64 acres in size will contribute twice as much production of oil and gas (or twice the pore space volume for CCS) as a thirty-two acre tract. Second, given that pooled drilling units typically are not too large in size—historically, they were seldom more than 640 acres and often were smaller—properties of the subsurface often will not vary dramatically from one end of a drilling unit to the other. Third, a surface-acreage allocation is simple for regulators to administer and for landowners to understand.

bb. Allocations based on both acreage and additional factors

The allocation of costs and revenue under fieldwide unitization typically is more complex than under pooling, where costs and revenues are typically allocated based on a single factor, surface acreage. For the allocation of revenue and costs under unitization, the regulator may use a formula that includes several factors, and these factors often differ from one unitization agreement or order to the next. The greater complexity of cost and revenue allocations under unitization, compared to pooling, may be justifiable for various reasons.

One of the major reasons relates to the subsurface formation from which hydrocarbons are being produced. A formation’s porosity, permeability, vertical thickness, and its depth beneath the surface can vary from one of the formation to another, as can the quality and amount of hydrocarbons present. Given that unitization orders typically cover a larger area than pooling orders,¹¹¹ the amount of variation in a subsurface formation likely will be greater across a fieldwide unit than a pooled drilling unit. A second reason relates to the fact that unitization orders often are used to facilitate secondary recovery operations.

¹¹⁰Keith B. Hall and Hannah J. Wiseman, HYDRAULIC FRACTURING: A GUIDE TO ENVIRONMENTAL AND REAL PROPERTY ISSUES 20 (American Bar Ass’n 2017).

¹¹¹Historically, most pooled orders entered for natural gas production covered areas 640 acres or less, while pooling orders entered for oil production tended to be smaller. The fieldwide unitization order in *Trout v. Wyoming Oil & Gas Conservation Commission*, 721 P.2d 1047 (Wyo. 1986) covered about 7,385 acres. The fieldwide unit in *Gilmore v. Oil & Gas Conservation Commission*, 642 P.2d (Wyo. 1982) covered approximately 31,065 acres.

In some cases, when considering the field as a whole, it may make economic sense to transition from primary production to secondary recovery, even though there may be portions of the area to be covered by a fieldwide unit where primary production can still be done profitably. In such cases, fairness may dictate use of formula that gives some additional compensation to tracts where profitable primary production operations will be terminated for the good of the fieldwide unit as a whole.

The selection of a formula for allocating costs and revenues of unit operations is often complex and contentious. In *Trout v. Wyoming Oil and Gas Conservation Commission*, several persons having oil and gas rights in an area became interested in switching from primary production to secondary recovery operations.¹¹² They notified the regulator of this interest and formed a technical committee to study the potential for secondary recovery and to develop possible formulas for allocating costs and revenues from such operations.¹¹³ The companies with operating rights in different portions of the field favored different formulas.¹¹⁴

The various persons with operating rights and other persons who held royalty rights (but no operating rights) met in December 1983 and considered various potential formulas for allocating costs and revenue. They held five votes and eventually reached significant consensus, though not unanimity. Just over 82% (in interest, not heads) of the operators and just over 93% (in interest) of the royalty owners supported a plan to allocate costs and revenues under a formula based 47.5% on a tract's production during the preceding six months, 47.5% on the remaining proved developed and producing reserves, and 5% on the original oil in place.¹¹⁵ Wyoming's oil and gas regulator ordered an operator to implement compulsory fieldwide unitization based on the formula approved at the December 1983 meeting. A party that favored a different formula appealed, but the Wyoming Supreme Court upheld the regulator's unitization order.¹¹⁶

In *Gilmore v. Oil & Gas Conservation Commission*, operators in an oilfield formed technical committees and subcommittees to consider unitization plans and potential allocation formulas.¹¹⁷ The committee concluded that overall production from the field would be substantially increased by unit operations, but the operators had trouble agreeing to an allocation formula. They met, considered 71 different formulas, and held votes on nearly 60 of the formulas.¹¹⁸ They could not come to a consensus because the various owners wanted to use different formulas, with each of them favoring a formula that would maximize their share of revenue. To break the deadlock, they used a computer to analyze the patterns of their prior voting and to develop a compromise proposal that gave varying weight to eleven different factors.¹¹⁹ They obtained a vote of 75.89% in support of the compromise proposal and the Wyoming Oil & Gas Conservation Commission entered a unitization order based on that proposal. An operator that preferred a different formula appealed, but the Wyoming Supreme Court upheld the unitization order.¹²⁰

ii. How to deal with owners who do not wish to participate in the upfront costs and risks of an operation

Another issue that will need to be determined is how the obligation to pay costs will be handled with respect to owners in a unit who do not wish to "participate" in an operation, where to "participate" means to pay one's

¹¹²721 P.2d 1047, 1048 (Wyo. 1986).

¹¹³*Id.*

¹¹⁴*Id.* at 1048-9.

¹¹⁵*Id.* at 1049. Production during the preceding six months might be a rough measure of the continuing viability of primary production in an area. The amount of proved developed producing reserves might be a measure of how much recoverable oil remains beneath a tract.

¹¹⁶*Id.* at 1054.

¹¹⁷642 P.2d 773, 774 (Wyo. 1982).

¹¹⁸*Id.* at 775.

¹¹⁹*Id.* at 775.

¹²⁰*Id.* at 781.

share of costs out-of-pocket and share in the risk that an operation might lose money and never recover its costs.¹²¹ No state forces an owner in a unit to pay for costs out-of-pocket and incur the risk that the operation might lose money. In dealing with non-participating owners in pooled drilling units, states typically used one of three main approaches, or a hybrid approach that combines two or more of the main approaches. These are: (aa) the “free-ride” approach, which is modeled on co-ownership rules, (bb) the “risk-charge” approach, which is modeled on terms commonly used in oil and gas joint operating agreements, and (cc) the “surrender of working interest approach,” which is modeled on a party’s granting of an oil and gas lease or, if the party is an oil and gas leaseholder, that party’s assignment of its leasehold interest. The subsections of this White Paper below will discuss those three approaches, as well as (dd) hybrid approaches and (ee) the potential to apply whatever approach a supermajority of parties have consented to use.

aa. The “free-ride” or co-ownership model

The cost-model that is most generous to non-participating landowners is the “free-ride” approach, which is similar to the law’s treatment of co-owners. Consider, for example, the default rule for handling costs of oil and gas operations as between co-owners. In most states, though not in Louisiana or West Virginia, a co-owner of the oil and gas exploration and production rights in a tract generally has the right to conduct oil and gas operations without the necessity of obtaining consent from the other landowners. Further, even in Louisiana and West Virginia, a co-owner may conduct oil and gas operations in certain circumstances without the consent of the other co-owners.

When a co-owner conducts operations without the consent of other co-owners, the co-owner who is conducting the operations cannot force the non-consenting co-owners to pay for a share of the costs of the operations out-of-pocket. Thus, the burden of putting up capital and the risk of loss in the event that the operations lose money falls entirely on the co-owner who conducts the operations. If the operations produce revenue, the co-owner who is operating can keep all the revenue until he recovers his reasonable costs of the operations. After that break-even or “payout” point, the co-owner who is conducting the operations must share subsequent net revenue—the subsequent revenue minus subsequent costs—with the other co-owners, with each co-owner being entitled to a fraction of net revenue that equals his fractional ownership share in the co-owned land.

This model is generous toward non-participating owners because, in the event that the operations are profitable, they receive their ownership share of profits, even though they incurred no risk. For example, a 10% participating landowner would have to put up capital to conduct the operations, incur risk that the operations might lose money, and in return would obtain 10% of profits. A 10% non-participating landowner would put up no capital, incur no risk, but would still obtain 10% of profits. This model is contrary to what one would normally expect in commercial agreements, because parties typically believe that there should be a link between risk and reward. Most parties will not agree to take on some risk without receiving a corresponding opportunity for reward. Further, this model encourages co-owners to be “free riders” who have no objection to a project, but who refrain from participating because they prefer to let other co-owners bear all the risks (a ploy that many people see as unfair).

Notably, in the oil and gas industry, there are examples in which co-owners of oil and gas rights enter an agreement that gives one of the co-owners a “free ride.” The free-riding party is sometimes called a “carried interest” because other parties carry that party’s burden of supplying capital and incurring

¹²¹Sometimes, “consent” is used, rather than “participate.”

risk. But when parties enter such an agreement, the party that becomes a carried interest is given the free ride in exchange for supplying other value. For example, if a party originally was the sole owner of certain oil and gas rights, that party might assign a fractional interest to another party, and all or part of the compensation that is paid by the assignee to the assignor will be the assignee's obligation to give the assignor a free ride as a carried interest. Accordingly, the typical farmout agreement does not provide support for the fairness of a free ride in the context of pooling or fieldwide unitization, and instead gives evidence to the contrary. The farmout agreements show that, within the oil and gas industry, companies view the act of giving someone a free ride as a carried interest to be a burden or cost that a party may agree to bear in return for receiving some benefit (such as an assignment of lease rights), and that having a free ride as a carried interest is a benefit that a party may receive in return for granting some benefit to a counterparty (such as a partial assignment of lease rights).

Nevertheless, a state might choose to follow this model in the case of CO₂ injection. Someone advocating this model could argue that the position of parties who own pore spaces beneath tracts in a CCS unit are similar to co-owners. Although they do not co-own the same pore spaces, they each own a portion of the pore spaces in a common formation, and no owner of a tract in the unit can inject CO₂ into the common formation without having the CO₂ migrate into pore spaces beneath tracts owned by other tract owners. Thus, each tract owner should be seen as having a fractional ownership in the common formation. Further, although the cost-model that applies amongst co-owners is not the cost-model that parties would commonly apply in a commercial agreement, it is the model that states almost universally apply in certain contexts, such as between co-owners when one or more of them is conducting operations without the consent of the others.

Further, some states apply the free-ride cost-model in the context of oil and gas pooling, which is arguably analogous to unitization for CCS. The free-ride approach is, however, the least common model for handling costs in the context of oil and gas pooling—probably because it is seen as generous to non-participating parties. A handful of states use this approach for oil and gas pooling, including Alaska,¹²² Arizona,¹²³ Indiana,¹²⁴ and Missouri.¹²⁵ Supporters of the free-ride cost-model can also point to these states—not to show that it is a commonly used model in oil and gas pooling, because it is the least commonly used—but to show that there is some use of this model in the oil and gas context.

bb. The risk-charge or JOA approach

A more common approach to handling costs in the context of oil and gas pooling is the “risk-charge” approach. This approach seeks to link risk and reward in a way similar to one of the main ways in which parties to certain commercial agreements do. In particular, this method copies the risk-reward scheme that is used in an oil and gas joint operating agreement (JOA). These agreements are commonly entered by individuals or companies that each own an interest in the right to conduct oil and gas operations in an area where the regulator (or the parties) has decided that coordinated, joint operations should be used. A joint operating agreement typically appoints one party as the “operator,” specifies an initial drilling operation in which all parties will participate, and specifies how decisions will be made about potential operations subsequent to the initial operation in which all parties agree to participate.

¹²²Alaska Stat. § 31.05.100 (providing that non-participating lessee is responsible for reimbursing operator for non-participant's share of costs, but that reimbursement is required only out of production).

¹²³Ariz. Stat. § 27-505(A).

¹²⁴Ind. Code 14-37-9-3.

¹²⁵Missouri Stat. 259.110.

JOAs typically provide that, if subsequent operations are undertaken, each party can choose whether it wishes to participate in the costs of the subsequent operation. A party that chooses not to participate in costs of a subsequent operation is often called a “non-consenting” party. The circumstance in which one or more parties to the JOA “go non-consent” for a subsequent operation is similar to that when there is a non-participating landowner in a well being drilled for a pooled drilling unit. Thus, the approach that joint operating agreements take with respect to non-participating parties shows how parties choose to allocate risk and reward in a commercial agreement that is somewhat analogous to pooling. So, how do JOAs handle the circumstance in which a party goes non-consent? The almost universal practice in joint operating is to link risk and reward by imposing a “risk fee” or “risk charge” or a “risk penalty” on parties who choose not to participate in costs.

When a JOA party goes non-consent for a subsequent operation, the party pays nothing out-of-pocket. This is similar to the free-ride approach. If a well produces revenue, the operator and other participating parties withhold and keep the non-participating party’s share of revenue until that withheld revenue equals the non-participating party’s share of costs. This is also similar to the free-ride approach. But under the “risk-charge” approach, after the non-participating party’s share of actual costs have been recovered from production, the operator and participating parties continue to withhold and keep the non-participating party’s share of production revenue until that revenue also pays to the participating parties a *risk charge* that rewards them for taking the risk and paying the costs of the operation. In the oil and gas joint operating agreement context, the joint operating agreement will specify the amount of the risk charge.

Often, the risk charge is set at 100% or 200% of the non-participating party’s share of costs. If the risk charge is 100%, the non-participating party will begin to receive its share of revenue after the well has paid for itself twice—once to cover the costs of the well and a second time to cover the risk charge that is set at 100% of the costs. If the risk charge is set at 200%, the non-participating party will begin to receive its share of revenue once the operation has paid for itself three times—once to cover the costs and then twice more to cover the risk charge.

Many states mimic this approach when the state regulator issues a pooling order. In such jurisdictions, if an oil and gas leaseholder that is not the operator chooses not to “participate” in an operation, that leaseholder will not be responsible for paying any costs of the operation out-of-pocket.¹²⁶ Instead, the operator and other participating parties will pay the costs of operations and also will pay the lease royalties owed to the non-participating leaseholder’s lessor for the portion of production allocated to the lessor’s tract. But in return for doing this, the participating parties will withhold and keep the non-participating leaseholder’s share of revenue until that revenue has covered both the non-participating leaseholder’s share of costs and a risk charge whose amount is set by statute, regulation, or order of the regulator.

It is notable, however, that many of these states give different treatment to a landowner whose land is not subject to an oil and gas lease. For example, Louisiana follows the risk-charge approach with respect to oil and gas leaseholders, but Louisiana uses the “free-ride” or carried-interest approach with respect to “unleased” landowners. There are several other states that use the risk-charge approach for oil and gas lessees, but which treat unleased owners differently, though without giving the unleased owners a complete free ride. These states’ approach is discussed later in this White Paper as the 7/8 – 1/8 hybrid approach.

¹²⁶In most cases, the operator of a drilling unit will be an oil and gas company that holds mineral leases covering one or more tracts in the unit. Assuming this is the case, it is possible that the operator may hold mineral leases covering all tracts in the unit. Often, however, some tracts may be covered by a mineral lease granted to an oil and gas company other than the operator and some tracts may be unleased.

In oil and gas pooling, the risk-charge approach is the most common approach for handling costs.¹²⁷ States that follow the risk-charge approach include Alabama,¹²⁸ Colorado,¹²⁹ Idaho,¹³⁰ Louisiana (for non-participating oil and gas lessees),¹³¹ Michigan,¹³² Mississippi,¹³³ Montana,¹³⁴ Nebraska,¹³⁵ Nevada,¹³⁶ New Mexico,¹³⁷ New York,¹³⁸ North Dakota,¹³⁹ Ohio,¹⁴⁰ Texas,¹⁴¹ Utah,¹⁴² and Wyoming.¹⁴³

cc. “Surrender of working interest” approach

The third and final main approach to costs in the oil and gas pooling context can be called the “loss of working interest” approach or the “imputed-lease” approach. This approach also mimics the allocation of risk and reward in a way similar to the way that some market participants do. In particular, landowners seldom drill their own oil and gas wells. Instead, it is much more common for them to grant oil and gas leases that reserve a lease royalty to the landowner. This lease royalty entitles the landowner to a specific fraction of the oil or gas produced (or the value of it), and this royalty fraction typically is set at one-eighth to one-fourth of the total production, and gives the leaseholder the right to drill (but seldom the obligation to do so), and the right to keep the portion of production that does not go to satisfying the landowner’s royalty.

In return, the landowner typically receives several benefits. First, the leaseholder gives a guaranteed, upfront payment (typically called a “bonus”) to the landowner. Second, the leaseholder will pay all costs of any exploration, drilling, and production that it decides to conduct, and the leaseholder will bear the entire economic loss if the operations lose money. This is a substantial benefit to most landowners because drilling is expensive, and many landowners could not afford to finance the costs, and it is not uncommon for oil and gas activities to lose money. Further, the leaseholder provides the know-how or expertise necessary for any exploration and development.

If an unleased landowner in a drilling unit decides not to participate in costs, that person’s position will resemble the position of the lessor under an oil and gas lease in some ways. For example, like the lessor under an oil and gas lease, the unleased landowner will bear no risk and pay no costs out of pocket. Instead, the participating parties will pay all the costs and bear all the risk of unit operations—somewhat like an oil and gas lessee who conducts lease operations. Accordingly, a case can be made for treating a non-participating landowner in a unit as if they *had granted* an oil and gas lease to the unit operator or participating parties.

Some states follow this approach to risk and reward when the state creates a drilling unit and pools the separately owned interests in the unit. In such states, if an unleased landowner does not voluntarily agree to participate in the costs of unit operations, the law will require the operator to pay that unleased owner

¹²⁷See, e.g., Patrick Martin and Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW (abridged edition) § 944; Keith B. Hall, Single Well Spacing and Pooling: State Spacing and Jurisdiction Over Conservation, Rocky Mountain Mineral Law Fdn. Special Inst.—Advanced Landman’s Institute (2019).

¹²⁸Ala. Code § 9-17-13.

¹²⁹Colo. Rev. Stat. § 34-60-116(7)(b).

¹³⁰Idaho Code § 47-320.

¹³¹La. Rev. Stat. 30:10(A).

¹³²Mich. Comp. Laws 324.61513(4); Mich. Admin. Code R. 324.1206(4).

¹³³Miss. Code § 53-3-7(2)(g).

¹³⁴Mont. Code § 82-11-202.

¹³⁵Neb. Rev. Stat. § 57-900(2).

¹³⁶Nev. R.S. 522.060(4).

¹³⁷N.M. Stat. § 70-2-17(C).

¹³⁸N.Y. Env. Cons. Law § 23-0901(3).

¹³⁹N.D. Cent. Code § 38-08-08(3).

¹⁴⁰Ohio Rev. Code § 1509.27.

¹⁴¹Tex. Nat. Res. Code §§ 102.013 and 102.052.

¹⁴²Utah Code § 40-6-6(6).

¹⁴³Wyo. Stat. § 30-5-109(g).

an upfront fee (analogous to a lease bonus) and a share of the production that is allocated to that tract (a share analogous to a lessor's lease royalty).

If a tract in a pooled drilling unit is not unleased, but is subject to an oil and gas lease to a leaseholder who chooses not to participate in the costs of drilling, that non-participating leaseholder bears no risk. In such a case, the non-participating leaseholder's position is somewhat like that of a leaseholder that bears no risk because it has assigned its lease to someone else. Thus, a case can be made for treating that non-participating leaseholder as if it had assigned its rights to the operator or the participating parties. When a leaseholder makes an assignment, it often receives some benefit in return for the assignment—perhaps a cash payment or an “overriding royalty” (a fraction of production) or a combination of both. An overriding royalty, even if it is the only compensation retained in return for an assignment, typically is smaller than the typical lessor's royalty under an oil and gas lease. Thus, under a surrender of working interest approach to costs in a pooled unit, a non-participating leaseholder may be paid a fee, then be treated as if it did not hold an interest as leaseholder in the area covered by the unit.

The most prominent of the states that follow the surrender of working interest approach is Oklahoma. Oklahoma's statutes do not expressly grant its oil and gas regulator—the Corporation Commission—the authority to utilize the surrender of working interest approach. Instead, Oklahoma's statute requires that any pooling order issued by the Corporation Commission to “be upon such terms and conditions as are just and reasonable.”¹⁴⁴ The Corporation Commission developed the surrender of working interest approach by way of its orders, and the Commission's use of the approach has been upheld by the Oklahoma Supreme Court.¹⁴⁵ Several other states have adopted statutes that authorize use of the surrender of working interest approach, including Arkansas,¹⁴⁶ Illinois,¹⁴⁷ Kentucky,¹⁴⁸ Pennsylvania,¹⁴⁹ South Dakota,¹⁵⁰ and West Virginia.¹⁵¹

dd. Hybrid or combination approach

Some states follow an approach that adopts elements of two or more of the approaches noted above. For example, Louisiana follows the risk-charge approach with respect to owners who are oil and gas leaseholders. But with respect to “unleased owners”—either landowners whose land is subject neither to a mineral lease nor a mineral servitude, and mineral servitude holders whose mineral servitude is not subject to a mineral lease—Louisiana follows the “free-ride” approach.

Some states use what one commentator called the “7/8-1/8 solution.”¹⁵² This approach borrows from the frequently used analogy that ownership is like a bundle of sticks, in that ownership typically includes a number of benefits, and that an owner can convey particular benefits to another person, while retaining the other benefits of ownership—just as a person who owned a bundle of sticks could remove one stick and give it to someone else, while retaining the remaining bundle. Under this approach, the owner of an unleased mineral interest is treated as someone who is both the mineral lessor (with a one-eighth lease royalty) and the mineral lessee of the same interest. In the owner's role as a mineral lessor, the operator of the unit and the participating parties pay that owner one-eighth of whatever portion of unit production is attributed that owner's tract. This payment is effectively a one-eighth royalty. To the extent that the owner

¹⁴⁴52 Okla. Stat. 87.1(e).

¹⁴⁵Anderson v. Corporation Commission, 327 P.2d 699, 700-1 (Okla. 1957).

¹⁴⁶Ark. Code § 15-72-304(b)(4).

¹⁴⁷Ill. Comp. Stat. 725/22.2(f).

¹⁴⁸Ky. Rev. Stat. 353.640 (3).

¹⁴⁹58 Pa. Stat. § 408(c).

¹⁵⁰S.D. Codified Laws 45-9-33.

¹⁵¹W. Va. Code, § 22C-9-7(b)(5).

¹⁵²Bruce M. Kramer, *Compulsory Pooling and Unitization: State Options in Dealing with Uncooperative Owners*, 7 J. Energy L. & Policy 255, 278 (1986).

is also treated as a mineral leaseholder who owns the working interest of a leaseholder, that owner's interest is subject to a risk charge. Thus, from the first barrel of production, the owner will receive a one-eighth royalty. In addition, if and when the costs and risk charge attributable to that owner's tract are recovered, that owner would begin to receive the remaining seven-eighths of production attributable to that tract, minus ongoing costs of operation.

ee. Approach that adopts whatever supermajority has consented to use

Generally, under state unitization laws, a prerequisite to the state's regulator issuing an order requiring unitization is that a supermajority of the owners in the unit have consented to a plan for unitization. Such plans of unitization, or a joint operating agreement that accompanies the unitization plan, may specify how costs of an operation are handled for parties to the agreement who choose not to participate in an operation. But assuming the regulator enters an order establishing a fieldwide unit, how will costs for an operation be handled with respect to mineral owners within the unit who did not agree to the unitization plan if they choose not to participate in that operation?

One possible approach to costs of an operation, when a mineral owner who did not agree to the unitization plan also chooses not to participate in the operation, is to apply the same rule regarding costs as is contained in the unitization plan. Thus, if the unitization agreement provides for a risk charge, then a risk charge would be applied to an owner who does not consent to the unitization agreement and then does not participate in an operation conducted for the area that is subject to the unitization order.

IV. What states are doing so far in the context of CCS regarding holdout landowners

Below, this White Paper discusses what states have done so far regarding: (A) authorizing either a unitization-like process or an eminent domain process for a CCS operator to acquire the right to use pore spaces beneath property of holdout landowners; and (B) for states that have authorized a unitization-like process, what states have done with respect to compensation issues that arise under unitization.

A. Authority of CCS operators to use pore spaces beneath property of holdout landowners

Several states authorize use of a unitization-like process for obtaining pore space rights for CCS, while few authorize use of eminent domain for pore space rights for CCS.

1. Unitization-like processes for CCS

Several states have enacted statutes that authorize a state regulator to enter an order for a unitization-like process for CCS operations.¹⁵³ These include Alabama,¹⁵⁴ California,¹⁵⁵ Colorado,¹⁵⁶ Illinois,¹⁵⁷ Indiana,¹⁵⁸

¹⁵³Keith B. Hall and Hannah J. Wiseman, HYDRAULIC FRACTURING: A GUIDE TO ENVIRONMENTAL AND REAL PROPERTY ISSUES 263 (American Bar Association 2017) ("Although the terms 'pooling' and 'unitization' often are used interchangeably, prominent authorities give different meanings to the two terms.").

Further, the law recognizes a difference. The statutes that authorize the regulator to enter pooling orders are different from the statutes that authorize the regulator to enter unitization orders, and the requirements that must be met before a pooling order is authorized are different than the requirements needed to justify a unitization order. Compare, for example: La. Rev. Stats. 30:5 (unitization) on the one hand with 30:9 and 30:10 (pooling); N.M. Stats. §§ 70-2-17(B) (pooling) and 70-7-6 (unitization); 52 Okla. Stats. §§ 87.1(a) (pooling) and 287.4 (unitization).

¹⁵⁴Ala. Code § 9-17-162.

¹⁵⁵Cal. Pub. Res. Code § 71461.

¹⁵⁶Colo. Rev. Stat. § 34-60-141.

¹⁵⁷415 Ill. Comp. Stat. 185/15.

¹⁵⁸Ind. Code § 14-39-2-4.

Kentucky,¹⁵⁹ Louisiana,¹⁶⁰ Mississippi,¹⁶¹ Montana,¹⁶² Nebraska,¹⁶³ North Dakota,¹⁶⁴ Pennsylvania,¹⁶⁵ Utah,¹⁶⁶ West Virginia,¹⁶⁷ and Wyoming.¹⁶⁸

The process for obtaining an order under these CCS statutes appears to more closely resemble the process typically required for fieldwide unitization than pooling, in that most of these CCS statutes do not allow the regulator to issue a unitization-like order unless a specified percentage of the neighbors reach an agreement with the CCS operator or otherwise support the proposed CCS operation.¹⁶⁹ As noted before, this is close to a universal requirement for compulsory oil and gas unitization, but is not typically a prerequisite for compulsory oil and gas pooling. Further, the area through which a carbon dioxide plume from CCS operations will spread generally is anticipated to be large, and thus the unit areas for CCS will be large, more like the area typically covered by a fieldwide unitization order, rather than the typical compulsory pooling order.¹⁷⁰

2. Eminent domain for CCS pore space rights

Relatively few states authorize eminent domain for CCS. Louisiana's Geologic Sequestration of Carbon Dioxide Act, which was enacted in 2009, initially authorized the use of eminent domain for obtaining pore space rights for CCS. However, during the 2024 Regular Session of the Louisiana Legislature, this Act was amended to remove the authority to use eminent domain for obtaining pore space rights, except for a project located in Caldwell Parish.¹⁷¹ During the same legislative session, the Louisiana Legislature added the authority to use a unitization-like process for CCS.

In addition, although Alabama enacted CCS-specific legislation that would authorize the use of a unitization-like process,¹⁷² a long-existing Alabama statute authorizes the use of eminent domain to obtain subsurface storage rights for various gases, including carbon dioxide.¹⁷³

Further, in 2023, Arkansas amended its "Underground Storage of Gas Law," which had long authorized use of eminent domain to acquire subsurface storage rights for natural gas, to also allow the use of eminent domain for obtaining subsurface storage rights for various other gases, including carbon dioxide.¹⁷⁴

¹⁵⁹Ken. Rev. Stat. 353.808.

¹⁶⁰La. Rev. Stat. 30:1104.2.

¹⁶¹Miss. Code § 53-11-9.

¹⁶²Mon. Code § 82-11-204.

¹⁶³Neb. Rev. Stat. 57-1612.

¹⁶⁴N.D. Cent. Code § 38-22-10.

¹⁶⁵32 P.S. § 696.5.

¹⁶⁶Utah § 40-11-10.

¹⁶⁷W. Va. Code § 22-11B-19.

¹⁶⁸Wyo. Stat. § 35-11-315.

¹⁶⁹See, e.g., Ala. Code § 9-17-162 (two-thirds); Cal. Pub. Res. Code § 71461 (75%); Colo. Rev. Stat. § 34-60-141 (75%); 415 Ill. Comp. Stat. 185/15 (75%); Ind. Code § 14-39-2-4 (70%); Ken. Rev. Stat. 353.806 (51%); La. Rev. Stat. 30:1104.2 (75%); Mont. Code 82-11-204 (60%); N.D. Cent. Code § 38-22-08 (60%); 32 P.S. § 696.5 (75%); Utah Stat. § 40-11-6; W. Va. Code § 22-11B-19 (75%); Wyo. Stat. § 35-11-316 (80%, but reduced to 75% in certain circumstances).

¹⁷⁰Historically, pooled drilling units for oil and gas seldom were larger than 640 acres, and often were smaller, though there has been movement toward larger pooled units as it becomes common to drill horizontal wells with increasingly long horizontal laterals. In contrast, fieldwide units for secondary recovery of oil often are thousands of acres. For example, in *Trout v. Wyoming Oil & Gas Conservation Comm'n*, 721 P.2d 1047 (Wyo. 1986), the unitization order covered approximately 7,358 acres. In the Port Hudson Field in Louisiana, a unitization order covering approximately 47,380 acres was issued.

A unit created for CCS by an order from the North Dakota Industrial Commission (Case No. 30123) covered approximately 29,776 acres, one (in Case No. 29451) covered about 15,979 acres, one (Case No. 29889) covered about 4,954 acres, one (Case No. 30870) covered about 29,445 acres, one (Case No. 30874) covered about 28,845 acres, one (Case No. 30878) covered about 31,239 acres, and one (Case No. 28849) appears to cover a few thousand acres.

¹⁷¹See Louisiana Acts 2024, No. 620. The 2024 legislation left in place the authority to use eminent domain for obtaining rights-of-way for CO₂ pipelines for CCS, and even perhaps expanded this right by clarifying that the CO₂ pipeline owner and the CCS project owner did not have to be the same entity. A small exception to the repeal of eminent domain authority for obtaining pore space rights for CCS was that the 2024 amendment retained that authority for projects in Caldwell Parish, an exception designed to facilitate an already-proposed CCS project that has significant public support in that Parish.

¹⁷²Ala. Code § 9-17-162.

¹⁷³Ala. Code § 9-17-154 (authorizing "storage operator" to use eminent domain to acquire subsurface rights); see also Ala. Code § 9-17-150 (definitions of "storage operator" and "storage facility" and "gas").

¹⁷⁴Ark. Acts 2023, No. 140; see also Ark. Code §§ 15-17-602, 15-17-604.

B. How states have handled compensation issues under CCS unitization-like processes

As with oil and gas pooling or unitization, there will be at least two major issues to decide with respect to compensating holdout landowners who do not enter an agreement with the CCS operator. These are how to: (1) allocate revenue and costs as between different tracts; and (2) how to deal with owners who choose not to participate in costs.

1. Allocation of revenue as between tracts in the context of CCS

If a unitization scheme is used for granting the CCS operator the right to utilize pore spaces beneath the land of holdout landowners, one issue that will need to be resolved is how to determine the relative allocation of revenue as between tracts. Two main options are to allocate revenue and costs on a surface acreage basis, or to allocate revenue based on a more complex formula that considers several factors.

Most state CCS statutes that authorize a unitization process do not specify how to allocate revenue and costs when the statutory authority is used to create a unit. Most states' CCS statutes simply say something to the effect that compensation to non-participating landowners must be "equitable," but they do not specify a particular method of allocation. For example, Louisiana's Geologic Sequestration of Carbon Dioxide Act provides for unitization for CCS in Louisiana Revised Statute 30:1104.2. It requires that unitization orders "provide for just and equitable sharing of the benefits generated from use of ... tracts for CCS," though it prohibits unitization orders from varying the compensation terms provided in a contract between the CCS operator and the owner of a tract in the unit. The statute goes on to state that the order must specify a "method, formula, or other basis" for determining compensation for tracts in the unit, and:

In determining the method, formula, or other basis, the [regulator] may take into consideration such factors that include but are not limited to the computational modeling submitted by an existing or proposed storage operator, whether there is an impact to a tract, the extent of any impact to a tract, each separately owned tract's proportionate share of the total surface acreage contributed to the storage unit, the costs required to perform the unit operation, and the viability of any third-party geologic storage projects within the storage unit and any associated third-party contracts executed by an owner in interest.

Thus, the statute expressly authorizes the regulator to consider multiple factors of its choosing, though it also would seem to leave room for the regulator to base compensation on acreage alone.

Wyoming's statutes deal with unitization for CCS in Wyoming Statutes §§ 35-11-314 through 35-11-317. These statutes suggest that compensation should be based on pore space volume. Wyoming Statute 35-11-315 states that an application for an order for CCS unit operations must include, amongst other things, "[a] proposed plan for determining the quantity of pore space storage capacity to be assigned to each separately owned tract within the unit area and the formula or method by which each separately owned tract will be allocated the economic benefits generated by use of pore space in the unit area." That provision follows immediately after § 35-11-314, which defines "economic benefits" as "the equitable proportionate share of all financial proceeds due to the pore space owners in a unit area based upon each individual pore space owner's contribution of pore space storage capacity to a unit area." And it precedes § 35-11-316, which requires, as a prerequisite to issuing a unitization order, that the regulator find that "[t]he quantity of pore space storage capacity, and method used to determine the quantity of pore space storage capacity allocated to each separately owned tract within the unit area represents, so far as can be practically determined, each tract's actual share of the pore space included within the unit

area.” This does not explicitly prohibit the consideration of other factors, but it appears to require that pore space volume be one of the factors considered, and someone could argue that the intent was to make pore space volume the only criterion considered in determining relative allocations.

North Dakota’s statutes governing unitization for CCS (a process that North Dakota calls “amalgamation”) require that non-participating pore space owners must be “equitably compensated.”¹⁷⁵ The statute leaves it up to the North Dakota Industrial Commission (NDIC), the state agency that regulates CCS (as well as oil and gas activities and various other matters) to determine what constitutes equitable compensation. As of June 2025, the NDIC has entered six amalgamation (unitization) orders for CCS. Each of the six amalgamation orders has allocated revenue as between tracts on a surface acreage basis. The orders noted that some other method of allocation could be used, but the orders suggested that the NDIC did not have enough data to be comfortable choosing a more complex allocation scheme.

2. How to handle costs of CCS when an owner chooses not to participate

A separate issue from the determination of how to allocate revenue and costs as between different tracts, is the issue of how to handle the situation in which an owner (who has not entered an agreement with the CCS operator to address this issue) elects not to pay out-of-pocket its share of upfront costs.

There are at least three options (not counting hybrid approaches): the “free-ride” approach that is based on the analogy to co-ownership, a risk-charge approach that is analogous to the provisions in most oil and gas joint operating agreements, and a “surrender of pore space” approach that is analogous to a landowner’s granting a pore space lease (this approach would be analogous to the “surrender of working interest” approach used in the oil and gas pooling context in some states). Most states’ CCS statutes do not expressly deal with this issue. An exception is Utah’s statutes.

Utah’s CCS statutes authorize a unitization-like process that the statutes call “amalgamation.”¹⁷⁶ The statutes contemplate that use of the “free-ride” method of handling costs when owners who have not entered an agreement with the CCS operator do not voluntarily pay their share of costs out-of-pocket. Under this method, discussed earlier in this White Paper, a pore space owner who has not entered an agreement with the CCS operator cannot be compelled to pay a share of costs out-of-pocket. Instead, the operator can retain the share of profits allocated to such a non-participating owner’s tract until those retained profits have fully reimbursed the operator for that owner’s share of costs. Once the retained profits have fully reimbursed the operator, the owner who did not voluntarily pay costs will be entitled to the profits (subsequent revenue minus subsequent costs) allocated to his tract. However, Utah’s statute also provides that the CCS operator can also recover from retained profits, before beginning payments to the non-participating owner, the estimated share of costs for closing the CCS facility that are allocated to the non-participating owner’s tract. Arguably, it makes sense to allow the operator to recover this cost in advance because, by the time the CCS facility is ready for closure, there presumably will no longer be any ongoing CO₂ injections and no revenue or ongoing profits. Thus, if the operator is going to recover those costs from the non-participating owner’s share of profits, the recovery will have to be done while injections of CO₂ are still ongoing.

Wyoming’s CCS statutes require that an application for unitization for CCS include “[a] proposed operating plan providing the manner in which the unit area will be supervised and managed and, if applicable, costs allocated and paid, unless all owners within the proposed unit area have joined in executing an operating agreement or plan providing for such supervision, management and allocation and, if applicable, payment

¹⁷⁵N.D. Cent. Code § 38-22-08.

¹⁷⁶Utah Code § 40-11-10.

of costs.” This seems to contemplate that, one way or another, a unitization plan can require the tracts in the unit to have some responsibility for costs, but it seems to give the regulator the authority to consider various methods for dealing with costs.

In some cases, a potential complicating factor for using the free-ride approach or the risk-charge approach will be the challenge in determining the total revenue that should be shared with landowners collectively. In most cases in the U.S., the main source of economic benefit for a CCS operation will be a federal tax credit commonly called the “45Q” credit.¹⁷⁷ It should be possible to put an economic value on the 45Q federal tax credits that a CCS operator earns and on any credits the operator earns in voluntary carbon markets.¹⁷⁸ Further, if the CCS operation is used in conjunction with the manufacturing of a fuel and the CCS operator earns California Law Carbon Fuel Standard credits or similar credits, it should be possible to put an economic value on those too.¹⁷⁹

If, however, the CCS operation is used to enhance the value of another business owned by the CCS operator, and the CCS operation is not placed into a separate entity that transacts at arm’s length with the CCS operator’s other business whose value is enhanced, then it may be more difficult to determine the economic benefit of the CCS operations. If, for example, a company that makes steel, cement, hydrogen, or ethanol uses CCS to lower the carbon footprint of their operation, and that makes the product more attractive in certain markets, it may be challenging to put a value on that, though it may be possible to do so if the main way that CCS makes the product more valuable is by helping the product be exempted from a carbon tax of a specified amount. If it is difficult to put a value on the economic benefits of a CCS project, and the CCS operator has used leases or some other type of contract to acquire pore space rights from many landowners by voluntary agreement, that would perhaps support an argument for imposing a “surrender of pore space” approach that is analogous to imposing a pore space lease on the non-consenting landowners.

V. Revenue to government

In Louisiana, the primary source of local government revenue from industrial facilities, including carbon sequestration infrastructure, is ad valorem property taxation. In October 2024, the Louisiana Tax Commission issued a *Draft Emergency Rule for Tax Year 2025 (2026 for Orleans Parish)* that provides assessment guidance for “carbon capture pipelines” and “Carbon Sequestration Wells and Related Wells,” which includes both injection and monitoring wells. These rules are intended to standardize the valuation of CCS infrastructure across parishes. However, in cases where capture equipment is located in one parish and sequestration infrastructure in another, the property tax base may be concentrated unevenly. Additionally, the value of injection and monitoring wells alone may represent a relatively small share of the total capital investment associated with a CCS project.

At the state level, revenues may also be generated when carbon dioxide is sequestered beneath state-owned lands or water bottoms. Under Louisiana law¹⁸⁰, these revenues are allocated as follows: 30% to the Mineral and Energy Operation Fund, 30% to the governing authority of the parish in which the storage

¹⁷⁷The name derives from the section of the Internal Revenue Code where the CCS tax credit provision is found. See 26 U.S.C. § 45Q. Relevant regulations are found at 26 C.F.R. §§ 1.45Q-0 through 1.45Q-6.

¹⁷⁸Some companies will voluntarily purchase “carbon credits” that a seller can earn by carbon sequestration or other activities (such as planting trees) that sequester CO₂ in other ways or that reduce the amount of CO₂ emissions that otherwise would occur.

¹⁷⁹Companies that sell fuel in California can earn credits if the fuel has a low life-cycle CO₂ footprint, considering the manufacture or extraction of the fuel, the transport of the fuel to market, and the ultimate use of the fuel. If a company sells fuel that has a higher carbon footprint, the company is required to acquire credits, which they typically would do by purchasing the credits from a company that had earned credits. Some biofuels can qualify as having a low carbon footprint under California’s rules if the manufacturing of the fuel is combined with a CCS operation.

¹⁸⁰See La. Rev. Stats. 30:149, 30:209.2

occurs (or divided proportionally if more than one parish is involved), and the remaining 40% to the state general fund. While there have been proposals to establish an injection-based fee or severance-style tax¹⁸¹ on carbon sequestration, no such measure has been enacted to date. Some observers have noted that in the absence of such a mechanism, and where property tax revenues are modest, local government revenues directly associated with sequestration activity may be limited—particularly in cases where project components span multiple jurisdictions.

VI. Similarities and differences to oil and gas extraction

While CCS operations have some analogy to oil and gas development, CCS introduces specific technical requirements that must be carefully addressed. Thus, the legal framework discussed throughout this paper take these technical similarities and differences in mind.

For example, the geological characteristics of subsurface formations are fundamental to CCS projects. Effective CCS operations require a storage reservoir with adequate porosity and permeability to accommodate injected CO₂, as well as an overlying confining unit (seal) with sufficient integrity to prevent upward migration. The lateral continuity and structural integrity of these formations determine the extent of CO₂ migration, including the extent to which it will migrate across property boundaries.^{182 183}

The economics of CCS and oil and gas extraction also differ in terms of risk, revenue generation, and market structure, though both involve the movement of molecules through subsurface formations. Oil and gas projects involve investment under uncertainty: firms incur substantial upfront costs to explore, drill, and complete wells with the expectation that future production will generate sufficient revenues. These investments are subject to geologic, engineering, regulatory, and commodity price uncertainty. Revenues in oil and gas come from the sale of extracted hydrocarbons. Production, if successful, may continue for many years stemming from an initial upfront capital investment.

By contrast, the economics of CCS more closely resemble those of waste management or environmental compliance services. The primary value of CCS lies in its ability to abate carbon emissions rather than to produce a tradable commodity. In the United States, the most significant financial incentive is the federal Section 45Q tax credit, which currently provides up to \$85 per metric ton of carbon dioxide that is captured and permanently sequestered. The tax credit is received by the entity that captures and abates the emissions, which in turn contracts with separate service providers for the transportation and storage of CO₂. This arrangement is the inverse of oil and gas operations, where revenues accrue to the producer, who then procures midstream and downstream services.

Although CCS projects are supported by tax credits rather than commodity sales, market pressures are nonetheless relevant. Industrial producers increasingly seek to reduce the carbon intensity of their products in response to expectations from customers, investors, and global market trends that favor lower-emission goods.¹⁸⁴ These factors influence capital allocation decisions, alongside government policy.

In sum, while CCS and oil and gas operations share some physical and legal infrastructure, they rest on different economic models. These differences have implications for regulatory frameworks, compensation structures, and long-term planning for both private and public stakeholders.

¹⁸¹ See, e.g., La. Rev. Stats. 47:631, 47:633.

¹⁸² Ma, X., Plaksina, T., & Gildin, E. (2013, August 14), Optimization of Placement of Hydraulic Fracture Stages in Horizontal Wells Drilled in Shale Gas Reservoirs.

¹⁸³ Satter, A., & Iqbal, G. M. (2016). Reservoir life cycle and role of industry professionals. Elsevier BV, 127-136.

¹⁸⁴ See 2025 Gulf Coast Energy Outlook for a discussion on risks and opportunities associated with industrial decarbonization for the Gulf Coast region of the U.S.

VII. Conclusion

Carbon capture and storage (CCS) presents a novel application of well-established legal and regulatory tools. While the use of subsurface pore space raises questions distinct from those in oil and gas development, most of these issues can be addressed within existing legal frameworks. Property doctrines, leasing practices, servitude arrangements, and statutory mechanisms such as eminent domain or unitization all provide workable avenues for balancing the interests of landowners, operators, and the public.

The policy choices available to states and regulators discussed in this paper largely concern the allocation of rights and responsibilities among these parties. Lease and servitude agreements allow for flexibility and negotiated compensation, but they may be limited when voluntary consensus cannot be reached. Eminent domain offers certainty but requires careful calibration to ensure fair compensation and public acceptance. Unitization and pooling approaches provide another pathway, with variations in cost-sharing and revenue allocation that reflect differing policy priorities.

Each of these mechanisms involves tradeoffs between efficiency, perceived fairness, and administrative feasibility. The variation in approaches already visible across states illustrates that there is no single model, but rather a spectrum of options that can be adapted to local conditions and policy objectives. As CCS projects advance, clear and predictable rules for acquiring and compensating pore space rights can reduce uncertainty for investors, safeguard landowner interests, and help ensure that projects can proceed in a manner consistent with the broader public interest.

The purpose of this paper has been to outline the principal legal considerations and to highlight the tradeoffs among available policy options, rather than to prescribe a particular approach. In doing so, it seeks to provide legislators, regulators, and industry participants with a framework for evaluating and comparing different pathways.

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