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THE EUGENE KUNTZ CONFERENCE ON NATURAL RESOURCES LAW AND POLICY

FRIDAY, NOV. 10, 2023

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2023 Kuntz Conference Schedule

8:15 a.m. - 8:30 a.m.

Opening Remarks
Elisabeth Brown, President, Mineral Law Section of Oklahoma Bar Association

8:30 a.m. - 9:20 a.m. pg. 1

Oil & Gas Litigation Update
Joseph Schremmer, Professor, University of Oklahoma College of Law

9:20 a.m. - 10:10 a.m. pg. 63

Artificial Intelligence and Professional Responsibility
Melissa Mortazavi, Associate Dean of Academics, University of Oklahoma College of Law
Sarah Cravens, Professor, Washington & Lee University School of Law

10:10 a.m. - 10:20 a.m.

BREAK

10:20 a.m. - 11:10 a.m.

Oil and Gas Securitization
Chad Smith, Kirkland & Ellis LLP
Jeff O'Connor, Kirkland & Ellis LLP

11:10 a.m. - 12:00 p.m. pg. 85

The Energy Lease: Reviewing Its Use in the Oil and Gas, Mining, and Renewables Industries
Andy Graham, Steptoe & Johnson PLLC

12:00 p.m. - 1:10 p.m.

NETWORKING LUNCH

1:10 p.m. - 2:00 p.m. pg. 115

Drafting and Negotiating Instruments to Acquire Pore Space Rights for CCS
Keith Hall, Professor, LSU School of Law

2:00 p.m. - 2:50 p.m. pg. 255

OCC Regulatory Roundtable: Current Issues, Hot Takes, and Musings
Eric Huddleston, Elias Books Brown & Nelson, P.C.
Matt Allen, Fox Rothschild LLP
Ben Brown, Charney Brown, LLC

2:50 - 3:05 p.m.

BREAK

3:05 - 3:55 p.m. pg. 306

Lease Expiration and the Cessation of Production Clause after Tres C, LLC v. Raker Resources, LLC
Travis Brown, Mahaffey & Gore, P.C.
Jeromy Brown, McCalla Brown Patel
Leah Rudnicki, The Rudnicki Firm
Kyle Domnick, Hodgden Law Firm, PLLC
Brad Welsh, GableGotwals

4:00 p.m.

ADJOURN

OIL & GAS LITIGATION UPDATE

Joseph Schremmer

2022-23 Recent Developments

JOSEPH SCHREMMER

ASSOCIATE PROFESSOR

UNIVERSITY OF OKLAHOMA COLLEGE OF LAW

Oklahoma Appellate Decisions

Tres C, LLC v. Raker Resources, LLC,
2023 OK 13

- Issue: Whether trial court erred in cancelling a lease following 90 days of unprofitable production based on the lease's 60-day cessation of production clause.
- Held: It was error to apply a 90-day accounting period to determine a cessation of production in paying quantities based on a cessation of production clause, because the proper accounting period is a reasonable time under the circumstances.
- Reasoning and Takeaways
  - Cessation clause not intended to define accounting period
  - The clause is triggered when production has already ceased
  - *Hoyt v. Continental Oil Co.* and *French v. Tenneco Oil* are distinguishable because they involved wells that had clearly ceased capability of production in paying quantities
  - The cessation clause intended not to eliminate the temporary cessation of production doctrine but to provide the lessee a grace period to commence operations when a cessation occurs

Oil Valley Petroleum, LLC v. Moore,
2023 OK 90

Issue: Whether holder of the shallow rights under a common oil and gas lease breached a duty to (i) the owner of an ORRI in the shallow rights and (ii) the owner of the deep rights in the lease, by releasing the shallow rights.

Held: Case remanded because fact issues preclude summary judgment on the key issues.

Reasoning and Takeaways

- Deep rights owner failed to establish that production from the shallow well held the lease through production in paying quantities because it did not advance any evidence of expenses.
- An overriding royalty interest may be extinguished by a release of the underlying lease unless the release is the result of fraud or a breach of a fiduciary duty

Unanswered Questions

- May the holder of a divided portion of a common oil and gas lease surrender the entire lease?
- Is it “constructive fraud” for a WI owner to surrender a lease to terminate an ORRI when its release paved the way for a top lease to take effect?

Fitzpatrick v. Fitzpatrick,

2023 OK 81

Issue: Whether it was error in a divorce action for a trial court to defer distribution of units of membership interests in energy companies deemed marital property and to order husband to hold the interests in constructive trust for wife.

Held: No error, because trial courts enjoy wide discretion in how to value marital property and in ordering remedies like constructive trust.

Reasoning and Takeaways

- When faced with an asset "the value of which could not be determined at the time of property division," trial courts should use a deferred distribution method rather than attempt to value the assets at present
- Trial courts have discretion to order the owning spouse to hold property for the benefit of the other; no statutory authority necessary
- A constructive trust was justified here based on husband's history of breaching fiduciary duties and the importance of avoiding unjust enrichment at expense of wife

Hitch Enters., Inc. v. Key Operating, LLC,
(Okla. Ct. App. Dec. 30, 2022)

Issue: Whether the trial court erred in certifying plaintiff's putative class in this action for unlawful royalty deductions because commonality was defeated by (i) individual fact issues about the quality of gas at the wellhead and (ii) differing language in the royalty clauses of the class leases.

Held: No, certification was appropriate because the quality of gas at the wellhead and the varying royalty clauses did not justify individual adjudication.

Reasoning and Takeaways

- Because the gas from all wells was commingled in the defendant's gathering system, it could not be shown what, if any, degree of gathering, compression, transportation, dehydration, or processing might have been necessary to render gas from any individual well marketable
- The lease differences are irrelevant, the court explained, because "if all of the Class leases are subject to the implied covenant to market, and [defendant] breached that covenant by charging Class members for processing costs, it does not matter what individualized language in an individual lease gave rise to the implied covenant to market"

Oklahoma Trial-Level Cases

Nash Fam. Min. Trust v. Merit Energy Co.,
(Texas Cnty. D. Ct. May 10, 2023) (appeal filed)

Issue: Whether lessee improperly deducted transportation and fraction (T&F) costs before calculating royalty on NGLs processed and sold at Mont Belvieu, Texas.

Held: Yes, marketable product doctrine required royalty to be calculated on the value of purified commodity NGLs at Mont Belvieu and not on the proceeds received under a netback pricing contract for an upstream sale of the raw gas to third-party midstream company.

Reasoning and Takeaways

- "At the well" and "proceeds" language in leases did not negate the implied duty
- The transfer of custody to midstream company in exchange for index-based price was not a true sale to satisfy the marketable product rule
  - Relies on *Pummill v. Hancock Exploration, LLC*, 2018 OK CIV APP 48
  - Rejects *Fawcett v. Oil Producers of Kansas, Inc.* (Kan. 2015)
- Marketability defined based on the requirements of the market that lessee chooses or intends for the gas—here the "pipeline market" (i.e., downstream market)
- Defines a "market" based on a multi-factor incorporating an economist's definition of a "market"

Gulf Exploration v. Okla. Energy Acquisitions, (Kingfisher Cnty., Oct. 3, 2022) (appeal filed)

Issue for Jury Trial: Whether OEP is liable for negligence, nuisance and trespass for fracking into the Mississippian and contaminating and interfering with production from Gulf's well.

Verdict: Liability for nuisance and negligence, but not trespass.

Damages: $2,000,000 for each of nuisance and negligence claim (the latter discounted by 20% for Gulf's comparative fault)

Issues Appealed

- Whether the trial court erred in admitting evidence of other fracking lawsuits filed against the defendant in Kingfisher County.
- Whether the trial court erred in refusing to direct a verdict in favor of defendant because the plaintiff failed to adduce evidence sufficient to establish causation.

Oklahoma Federal Cases

Chesapeake Operating, LLC v. C.C. Forbes, LLC,
(W.D. Okla. 2023) (appeal filed)

Issue: Whether Oklahoma's statute prohibiting indemnity provisions in "construction agreements" applies to oilfield service contracts like MSAs.

OKLA. STAT. tit. 15, § 221(A) defines a "construction agreement" as "a contract, subcontract, or agreement for construction, alteration, renovation, repair, or maintenance of any building, building site, structure, highway, street, highway bridge, viaduct, water or sewer system, or other works dealing with construction, or for any moving, demolition, excavation, materials, or labor connected with such construction."

Held: No, because oil and gas wells are not a "structure" within the meaning of the statute.

Reasoning and Takeaways

- The plain meaning of a "well" is "[a] hole or shaft sunk into the earth to obtain a fluid, such as water, oil, or natural gas," i.e., not ordinarily understood as a "structure"
- Wells are not like any of the other "structures" listed in the statute
- Legislative history supports interpretation
- *But cf. Jet Maintenance, Inc. v. Devon Energy Production Co., L.P.*, (W.D. Okla. June 9, 2022)

Lazy Ranch S. Props. v. Valero Terminal. & Distrib., (E.D. Okla. 2022) (appeal filed)

Issue: Whether plaintiff's evidence of trace amounts of contamination from defendant's petroleum products pipeline sufficed to establish tort liability.

Held: No, contamination without proof of harm is not actionable.

Reasoning and Takeaways

- "[A] plaintiff must establish that the alleged contaminants exist in sufficient quantities to constitute a nuisance or to render the environment harmful, detrimental, or injurious"
- Oklahoma "takings" clause requires a landowner show "substantial injury or unreasonable interference" with property
- "Pollution" as defined in Oklahoma regulations requires contamination that causes a nuisance or is harmful to the public health
- Administrative limits on pollution are relevant to determining what levels of contamination are actionable for private nuisance

Colton v. Continental Res., Inc., (E.D. Okla. 2022)

Issue: Whether in determining the amount in controversy for diversity jurisdiction under Class Action Fairness Act (CAFA) court must take into account interest alleged owing under Oklahoma's Production Revenue Standards Act.

Held: Yes, but only where unpaid interest is itself the primary amount in controversy.

Reasoning and Takeaways

- *Whisenant v. Sheridan Production Co., LLC* (10^{th} Cir. 2015) held that interest on underpaid royalties not to be included in calculating the amount in controversy under CAFA
- That case involved allegations of improper deductions, whereas this case sought unpaid interest on undisputed amounts of royalty.

Cline v. Sunoco, Inc., (10th Cir. Aug. 2023)

Issue: Whether the trial court's order entering judgment against Sunoco on plaintiff's $155 million claim for unpaid interest on late payments satisfies the 10th Circuit's requirements for finality so as to be appealable.

Procedural History: The 10th Circuit had twice before rejected Sunoco's attempts to appeal the judgment. This time, Sunoco moved under FRCP 60(b)(6), requesting the district court to modify its judgment to satisfy the requirements for finality. The district court denied the motion and Sunoco appealed the denial.

Held: The trial court's order did not satisfy the two requirements for finality and thus does not give the 10th Circuit jurisdiction. Therefore, the court's denial of the 60(b)(6) motion was error. The court remanded for the district court to reconsider Sunoco's motion.

- The trial court's judgment failed to (1) establish a formula for dividing the award to the class members because it did not address how the portions attributable to unknown and unlocatable mineral owners would be dealt with, and (2) provide for how unclaimed funds are to be distributed.

Texas Appellate Decisions

Van Dyke v. Navigator Grp.,

668 S.W.3d 363 (Tex. 2023)

“It is understood and agreed that one-half of one-eighth of all minerals and mineral rights in said land are reserved in grantors, Geo. H. Mulkey and Frances E. Mulkey, and are not conveyed herein,” held to reserve a ½ interest in the mineral estate.

Texas courts will *presume* that use of the fraction 1/8 in a grant or reservation refers to the entire mineral estate, unless language elsewhere in the instrument rebuts the presumption.

- The “estate misconception”
- The “ubiquitous 1/8 royalty”

Title to a ½ interest established on alternative ground, based on subsequent circumstantial evidence in the chain of title. The “title by presumed grant doctrine.”

- To establish must show:(1) a long-asserted and open claim, adverse to that of the apparent owner; (2) nonclaim by the apparent owner; and (3) acquiescence by the apparent owner in the adverse claim.”

Devon Energy Production v. Sheppard,
668 S.W.3d 332 (Tex. 2023)

Lease addendum providing that in calculating royalty,

> if "*any reduction or charge* for [postproduction] expenses or costs" has been "include[d]" in "any disposition, contract or sale" of production, those amounts "shall be *added to the . . . gross proceeds* so that [the landowners'] royalty *shall never be chargeable directly or indirectly with any costs or expenses* other than its pro rata share of severance or production taxes."

> Disclaimed any applicability of *Heritage Resources, Inc. v. NationsBank* and *Judice v. Mewbourne Oil Co.*

Held to create a "proceeds plus" lease.

Point Energy Partners Permian v. MRC Permian, 669 S.W.3d 796 (Tex. 2023)

Held that lessee's missed deadline under a continuous-drilling obligation was not excused, and the lease was not suspended, under a force majeure clause, because the true cause of the delay was the lessee's own mistake rather than a force majeure event.

Lessee alleged that a "well-stability" issue on well it was drilling on another, unrelated lease delayed its drilling rig causing it to spud the obligation well late.

In fact, the lessee accidentally scheduled the rig to spud two weeks too late, and the delay caused by the well-stability issue lasted only 30 hours.

Cactus Water Servs. v. COG Operating,
(Tex. App. 2023)

Held that produced water was granted to lessee under its oil and gas lease and thus was not owned by a third party under a saltwater lease.

Note the framing of the issue: "The parties' disagreement as to whether produced water is part of the mineral estate essentially depends on whether 'produced water' is, as a matter of law, water or if it is waste."

- Citing various regulatory definitions pertaining to "water" and oilfield "wastes," the court concluded that it is more like waste and thus part of the estate granted by an oil and gas lease.

Dissent argued that produced water does not pass under an oil and gas lease, although lessee does take an implied easement in the water as an element of the surface estate.

- Produced water is not a "hydrocarbon" within the ordinary meaning of the term and thus is not covered by the granting clause of the subject leases. Citing *Moser v. U.S. Steel Corp.* (Tex. 1984).

PBEX II, LLC v. Dorchester Minerals,

670 S.W.3d 374 (Tex. App. 2023)

Held that a nonoperating working interest under a JOA is subject to adverse possession and that Dorchester in fact adversely possessed such an interest from the true owner following 26 years of paying JIBs, receiving revenues, paying royalties, and making required elections under the JOA.

- No drilling or even "setting foot" on the surface of the unit was necessary to adversely possess the nonop interest.
- Going nonconsent did not interrupt the period of adverse possession

In the alternative, the JOA operator was held to have adversely possessed the interest on behalf of Dorchester.

- Analogizes an operator to the tenant in a lease with a landlord
- Tenants are recognized as having the power to adversely possess for the benefit of the landlord, even absent an agency relationship

Railroad Comm'n v. Opiela,

(Tex. App. June 30, 2023)

Held that RRC's permit program for production sharing agreement (PSA) wells are not tantamount to compulsory pooling and that an anti-pooling clause in applicant's oil and gas lease does not defeat the requirement that the applicant have a good-faith claim to the right to drill a horizontal well into the complainants' tract.

- "When [the Commission] grants a permit to drill a well it does not undertake to adjudicate questions of title or rights of possession. These questions must be settled in the courts."

However, the applicant failed to show that 65% of the affected interests had signed the production sharing agreement, as required by the PSA well permit application.

- Consents to pooling are not sufficient unless it is shown that the consents call for the same sharing of production as the PSA
- Applicant might pursue an allocation well permit instead

Foundation Minerals v. Montgomery,

(N.M. Ct. App. Oct. 2, 2023) (Applying Texas Law)

Held that a mineral estate purchase agreement (MEPA) was a binding contract despite argument by seller that the parties never mutually assented to the price under the contract's pricing formula.

The pricing formula provided: "Buyer agrees to pay Seller for the oil and gas Mineral Estate $15,535.19 per Net Royalty Acre (Net Royalty Acre being defined as: The equivalent of 1 Net Mineral Acre being leased at a 1/8th Royalty. For Example: 1 NMA leased at a 1/4th is equal to 2 NRA) owned by Seller in the lands covered by this Agreement (the "Purchase Price")."

Based on custom and usage, court implied a ¼ leasehold royalty interest for all unleased minerals and NPRIs of seller.

Other Jurisdictions Appellate Cases

Bay v. Anadarko E&P Onshore,

73 F.4th 1207 (10th Cir. 2023) (Colo.)

Held that the district court is bound by 10th Circuit's earlier prediction that Colorado law would follow Texas regarding the "material interference" requirement of the accommodation doctrine.

- Texas case law requires a surface owner to establish that a mineral owner's surface activities have completely precluded or substantially impaired the surface owner's preexisting surface use *and* that there is no was no reasonable alternative for the surface owner to be entitled to relief under the accommodation doctrine.

In prior appeal, court also stated that horizontal drilling would have constituted a reasonable alternative to the mineral owner's desired plan of vertical drilling.

Zavanna v. GEDECO, LLC,

994 N.W.2d 133 (ND 2023)

Held that the trial court in this lease termination action erred in placing the burden of proving that the bottom lease did *not* cease producing in paying quantities on the defendant owner of the bottom lease.

- The party asserting lease termination bears the burden to show that production permanently ceased and that the lessee failed to comply with the terms of a lease savings clause.

Held that the lease terminated following multiple cessations of production that were not excused by compliance with the 90-day cessation of production clause.

- During the first period, the lessee diagnosed a bad submersible pump and ordered a new pump, but did not get a rig on the hole to replace the pump for 143 days. Held: ordering a new pump was not "commencement of drilling or reworking operations" and even if it was, the operations weren't diligently pursued.
- During the second period, the well produced only 3 barrels of oil and 11 mcf of gas over 4 months. Distinguishing *Tres C, LLC*, the court held this was a total permanent cessation as a matter of law. No reasonable accounting period was necessary.

Northern Oil & Gas v. EOG Resources,

74 F.4th 899 (8th Cir. 2023)

1949: Anderson conveys ½ mineral interest to Youngblood.

1962: Anderson conveys a ¾ mineral interest in the same land to Johnson, reserving a ¼ mineral interest to himself.

Johnson's successor sued Anderson's successors to quiet title to a ½ mineral interest. Anderson's successors claimed ¼, leaving ¼ for Johnson's successors.

Applying North Dakota's *Duhig* rule (and a prior ND Supreme Court case analyzing the exact same deeds), the 8th Circuit held Johnson received ½ of the minerals and Anderson reserved nothing.

- "When there has been an overconveyance of mineral interests, the Supreme Court of North Dakota applies the rule of construction from *Duhig v. Peavy-Moore Lumber Co.*, 135 Tex. 503, 144 S.W.2d 878 (Tex. 1940)"

Contra Echols Minerals, LLC v. Green (Tex. App. Aug. 2023), applying *Trial v. Dragon*, 593 S.W.3d 312 (Tex. 2019), limiting *Duhig* to situations in which the grantor owns *the very interest* necessary to remedy the breach of warranty in the grantor's deed.

RECENT DEVELOPMENTS 2022–2023

Joseph Schremmer
Associate Professor
Director, Oil & Gas, Natural Resources and Energy Center
University of Oklahoma College of Law

PART ONE
OKLAHOMA APPELLATE DECISIONS

I. The Oklahoma Supreme Court holds that a cessation-of-production clause in an oil and gas lease does not contractually define the proper accounting period for testing production in paying quantities, in *Tres C, LLC v. Raker Resources, LLC*, 2023 OK 13.

A top lessee filed this cancellation action against a bottom lease (the Cowan Lease) on behalf of the lessor, Tres C, LLC, alleging that a 90-day period of unprofitability caused the lease to terminate by its own terms for failure to produce in paying quantities. Defendants Raker Resources (Raker) owned the Cowan Lease insofar as it covered the Cowan Well. Continental Resources and DewBlaine Energy owned the balance of the Cowan Lease.

Executed in 1955, the Cowan Lease provided for a 10-year primary term and a secondary term "as long thereafter as oil, gas, casinghead gas, casinghead gasoline, or any of the products covered by this lease is or can be produced."[1] The lease contained the following familiar savings clause:

> *If, after the expiration of the primary term of this lease, production on the leased premises shall cease from any cause, this lease shall not terminate provided lessee resumes operations for drilling a well within sixty (60) days from such cessation*, and this lease shall remain in force during the prosecution of such operations and, if production results therefrom, then as long as production continues.[2]

Owing largely to high pressures in the gathering line, production from the Cowan Well dipped and even ceased altogether from the end of September through December 2016, rendering the well unprofitable. Following various attempts by Raker Resources to buck the line pressure, including installing a compressor, the Cowan Well eventually reestablished a profitable level of production. Continental Resources undertook preparations to spud a new well on the lease, culminating in a spud date in March 2017. This suit followed.

Following a bench trial, the district court entered judgment terminating the Cowan Lease. It found that the lease failed to produce in paying quantities for approximately 90 days in October, November, and December 2016. The court also found that, alternatively, the Cowen Well was shut in on October 17 following two days of no production, constituting a cessation of production. It further found that no drilling or reworking operations were commenced on the premises within the

[1] 2023 OK 13, ¶ 2.
[2] *Id.* (cleaned up) (emphasis added by court)

60-day grace period provided by the lease savings clause.[3] The Court of Appeals affirmed on the ground that the district court's finding of a cessation of production was a factual finding not to be disturbed on appeal.

In granting certiorari, the Supreme Court was careful to cast the issue on appeal not as a review of fact findings but as a pure question of law: "[W]hether it was legal error for the trial court to apply a rule of law that analyzed only a 3-month window of time for assessing whether the Cowan Well had experienced a cessation of production in paying quantities such that the Cowan Lease expired by its own terms."[4] The court reversed, holding that three months is "as a matter of law, too short for determining whether a cessation of production in paying quantities has occurred."[5]

Tres C contended that a cessation in production in paying quantities occurs, triggering the 60-day grace period to commence drilling or reworking operations under the lease's savings clause, "any moment an interruption in actual, continuous profitable production occurs."[6] The lessee in such a situation must either commence drilling or reworking operations in compliance with the savings clause or otherwise resume profitable production before the end of the 60-day period. Raker countered that a cessation of production paying quantities triggers the savings clause only if it continues "for an unreasonable period of time gauged under all the circumstances from the perspective of a reasonable operator."[7]

The court adopted Raker's interpretation, citing two primary reasons. First, the cessation-of-production clause is only implicated "where production *has already ceased*."[8] For support, the court cited, *inter alia*, Dean Kuntz's *Law of Oil and Gas*, in which it is explained that "[I]f the 'production' requirement of the habendum clause is met, the cessation-of-production clause is not triggered."[9] Indeed, it is this very quality that characterizes the cessation-of-production clause as a *savings* clause, because it operates to substitute for production when such is unavailable to maintain the lease.

Second, the cessation-of-production clause does not define when a cessation of production has occurred, since, quoting Kuntz, "[i]t is not the purpose of the cessation of production clause to establish an accounting period for purposes of determining if production is in paying quantities."[10] This very observation was made by the Texas Supreme Court in the seminal paying quantities case, *Clifton v. Koontz*.[11] The *Tres C* court elaborated that to look to the savings clause to define the accounting period would be "wholly unworkable in the oil and gas industry" and inconsistent with Oklahoma jurisprudence because it would impose on lessees a duty to market production continually to maintain the lease.[12] Instead, Oklahoma case law provides that the period of time

[3] *Id.* ¶ 18.
[4] *Id.* ¶ 23.
[5] *Id.* ¶ 26.
[6] *Id.* ¶ 19.
[7] *Id.*
[8] *Id.* ¶ 28.
[9] *Id.* (citing 2 KUNTZ, LAW OF OIL & GAS § 26.6).
[10] *Id.* ¶ 29 (citing 4 KUNTZ, LAW OF OIL & GAS § 47.3(a)(1)).
[11] 325 S.W.2d 684 (Tex. 1959).
[12] *Tres C*, ¶ 29 (citing Pack v. Santa Fe, 1994 OK 23, ¶¶ 14–15, 17).

over which to determine profitability "is not measured in days, weeks, or months, but by a time appropriate under all of the facts and circumstances of each case," which would be considered relevant by a reasonable and prudent operator considering whether to maintain or abandon the lease.[13]

The court rejected Tres C's argument that *Hoyt v. Continental Oil Co.*[14] and *French v. Tenneco Oil Co.* [15] mean that "the period set forth in the savings clause overrides any common law requirement to utilize a reasonable time period."[16] Both *Hoyt* and *French* involved leases with the identical savings clause to the *Tres C* lease. In *Hoyt*, the plaintiff seeking lease cancellation alleged that there had not been production in paying quantities from the lease for a period of fourteen months (although the court only considered the first twelve months because the final two occurred post-petition).[17] Importantly, the well at issue did not completely cease producing hydrocarbons during this period.[18] The defendant lessee argued that the saving clause was not triggered unless there was a total cessation of production—in other words, that the word "production" in the savings clause does not mean the same thing as "production" means under the habendum clause. The court rejected this view, stating that where the primary term has expired and the effect of the savings clause is to modify the habendum clause, "there is a cessation of production if the habendum clause requires production in paying quantities and such requirement is not met."[19]

The court's next words are critical. "On this point the record clearly demonstrates that production in paying quantities was not obtained for an uninterrupted period far in excess of the 60-day provision in the lease executed by the parties. Where the parties have bargained for and agreed on a time period for a temporary cessation clause that provision will control over the common law doctrine of temporary cessation allowing a 'reasonable time' for resumption of drilling operations."[20] The court then quoted a New Mexico case, *Greer v. Salmon*,[21] which in turn quoted from a law journal article, Hazlett, *Effect of Temporary Cessation of Production on Leases and Term Royalties*, 10 Ann. Inst. Oil & Gas L. & Tax'n 201, 248, as follows:

> The courts have been unanimous in construing this clause as meaning that cessation of production for longer than the stipulated period cannot be considered 'temporary'. In effect, the provision is construed as giving the lessee a fixed period of time within which to resume production or commence additional drilling or reworking operations in order to avoid termination of the lease; the period of grace having been fixed by agreement of the parties, it cannot be extended by the courts, no matter what the circumstances or cause of the cessation.[22]

[13] *Id.* ¶ 30 (citing Barby v. Singer, 1982 OK 49, ¶ 6).
[14] 1980 OK 1.
[15] 1986 OK 22.
[16] *Tres C*, ¶ 31.
[17] *Hoyt*, 1980 OK 1, ¶ 4.
[18] *Id.* ¶ 6.
[19] *Id.* ¶ 10.
[20] *Id.*
[21] 479 P.294 (N.M. 1970).
[22] *Hoyt*, 1980 OK 1, ¶ 10 (quoting *id.*).

French involved a lease cancellation action brought following four months of *no* production from the lease during its secondary term. The defendant lessees argued that "a determination of cessation of production in paying quantities is dependent upon the selection of a proper time frame within which to base that calculation. Intertwined with these points is the contention that the 60-day period for resumption of operations specified in the lease does not become activated until the expiration of a reasonable period of time, thus giving the lessee a reasonable time to resume operations plus 60 days."[23] The court rejected this interpretation, quoting *Hoyt* for the proposition, "[w]here the parties have bargained for and agreed on a time period for a temporary cessation clause, that provision will control *over* the common law doctrine of temporary cessation allowing a 'reasonable time' for resumption of drilling operations."[24] The *French* court also rejected the argument (also made by Raker in *Tres C*) that this interpretation would require the lessee to drill a new well every time production ceases for any cause, even where the cause would otherwise be easily remedied. It again quoted *Hoyt*, this time quoting the provision from the Hazlett article: "In effect, the [savings clause] is construed as giving the lessee a fixed period of time within which to *resume production or commence additional drilling* or reworking operations in order to avoid termination of the lease."[25] Thus, *French* concluded that under the savings clause the lessee could maintain the lease either by drilling a new well or "restoring production in paying quantities by means the lessee determines to be advantageous under the circumstances."[26]

The *Tres C* court rejected the argument that *Hoyt* and *French* determined the accounting period for a paying quantities analysis by reference to the grace period of a cessation-of-production clause. The opinion gives three reasons. First, it explained that, at least in *French*, it was assumed that there had been a cessation of production and thus that these cases support the court's earlier conclusion that the 60-day clause comes into effect only after a cessation has occurred. Second, contrary to the Hazlett interpretation adopted by *Hoyt* and followed by *French*, the court stated that the cessation-of-production clause was "never designed to eliminate or avoid the operation of the temporary cessation doctrine."[27] Quoting the Kuntz treatise, the opinion demurs, stating,

> An indiscriminate application of such rule can, however, lead to results that the parties were not likely to have intended when they included such a clause in the lease. . . . The fact that the event which is designed to prevent termination is the commencement of drilling or reworking operations gives some indication of the purpose of the clause and the intention of the parties. It indicates that the parties are concerned with a situation where cessation of production is of the type that is remedied by drilling or reworking operations. Thus, the parties must have intended that the clause would become operative if a dry well is drilled or if a producing well ceases to be capable of producing in paying quantities. . . . *The resumption of operations clause was never designed to eliminate or to avoid the operation of [the temporary cessation] doctrine or to require that oil or gas be produced and marketed in a continuous, uninterrupted operation. It was intended to preserve a*

[23] *French*, 1986 OK 22, ¶ 7.
[24] *Id.* (emphasis added by *French* court).
[25] *Id.* ¶ 8.
[26] *Id.*
[27] *Tres C*, ¶ 34.

> *lease in order to permit a lessee to restore production if production should cease under circumstances that require drilling or reworking on his part in order to restore production.*[28]

In short, the court construed the clause to refer not to temporary cessations of production but cessations that would become permanent unless corrected by drilling or reworking operations. Since the production interruptions affecting the Cowan Well were not of the kind that required drilling or reworking operations to fix, the court found that it would improperly expand the purpose of the savings clause to apply it in this case.

Finally, the court stated that reliance on *Hoyt* and *French* was "misguided" because the court had previously, in *Pack v. Santa Fe Minerals*.[29] *Pack* explained the results in *Hoyt* and *French* on the ground that the wells in those cases were "*not* capable of production paying quantities, i.e., they were not 'producing' wells under either the habendum clause or the cessation of production clause."[30] The wells in *French* were incapable of producing oil or gas at all, whereas the wells in *Hoyt* were incapable of producing in paying quantities. The *Hoyt* case involved a fourteen-month period of unprofitability. While language in the *Hoyt* opinion (quoted above) might be read to mean that the 60-day period defined the permissible length of unprofitability, it is likelier that the court believed the lengthy period of unprofitability was sufficient to render the well incapable of producing in paying quantities and thereby trigger the 60-day clause. *Pack* made clear about the holdings in *French* and *Hoyt* is that the wells in those cases were both categorically incapable of producing in paying quantities at the time that the 60-day grace period kicked in.

Yet another aspect of *Pack* supports the court's position in *Tres C*. In *Pack v. Santa Fe Minerals*, the court reasoned that "[t]he term 'production' as used in the cessation of production clause must mean the same as that term means in the habendum clause," and consequently that the clause is "intended to come into play in the event that *production* from the well shall cease, i.e., the well becomes incapable of producing in paying quantities."[31]

In conclusion, the *Tres C* court reversed the district court's application of a 3-month accounting period and entered judgment in favor of Raker on the basis that Tres C failed to carry its burden of proof. Further, it found that any cessation of production in paying quantities would have occurred not on September 1 but on December 1, 2016, and this later date was within 60 days of Continental's spudding of a new well in January 2017. Thus, even if there was a cessation of production, the lessee resumed new drilling operations in compliance with the savings clause to continue the lease.[32]

[28] *Id.* ¶ 34 (quoting 2 KUNTZ, LAW OF OIL AND GAS § 26.13(b)) (emphasis added by court).
[29] *Id.* ¶ 35.
[30] *Id.* (emphasis in original).
[31] Pack v. Santa Fe Minerals, 1994 OK 23, ¶ 14 (emphasis in original).
[32] *Tres C*, ¶ 37.

II. The Oklahoma Supreme Court addresses the effect of the filing of a release by the owner of shallow rights in an oil and gas lease on an overriding royalty interest in the shallow rights and a divided working interest in the deeper rights, in Oil Valley Petroleum, LLC v. Moore, 2023 OK 90.

In this action to quiet title, plaintiff Oil Valley Petroleum (Oil Valley) asserted title to the working interest in oil and gas rights in the subject land at all depths pursuant to a 2017 top lease. Defendant Moore claimed to hold the working interest below the stratigraphic equivalent of 9,747 feet under a bottom lease (the Athan Lease) that was released of record in 2017 by the holder of the shallow rights, Staab Holdings (Staab).

The essential facts are these. Moore owned the deep rights in the Athan Lease plus an 1/8 of 8/8 overriding royalty interest in the entire vertical and horizontal extent of the leasehold. Staab owned the shallow rights in the Athan Lease down to the stratigraphic equivalent of 9,747 feet in the Ball 1-24 Well. In June 2017, Oil Valley acquired its top lease from the lessor of the Athan Lease. Then, in October 2017, Staab executed a release of "all its rights, title and interest in and to" the Athan Lease, which it then recorded in the Dewey County land records on March 5, 2018. Operating under its top lease, Oil Valley subsequently drilled the Holsapple 1-24-13XH well and completed it at a vertical depth of 11,524 feet—below the depths in which Staab owned rights in the Athan Lease.

On cross motions for summary judgment, Moore argued that its rights in the Athan Lease were continued by production by a marginal gas well, the Ball 1-24, and could not have been relinquished by Staab's release of the shallow rights. Oil Valley argued that Staab's release of the Athan Lease extinguished Moore's rights in the lease under the lease's surrender clause. Oil Valley argued in the alternative that any production from the well following the Staab release is attributable to Oil Valley's top lease, rather than the Athan Lease, and thus that Moore's failure to commence drilling operations for a new well under the Athan Lease's resumption of operations clause following the Staab release terminated the Athan Lease. Oil Valley further contested Moore's claim that the Athan Lease was held by production, noting that Moore had failed to produce any evidence of the costs associated with production from the well to establish production in paying quantities. The district court granted Moore's motion for summary judgment, the Court of Appeals reversed, and the Supreme Court reversed and remanded.

Boiled down to their essence, the issues on appeal presented the question of whether the holder of a divided portion of working interest under a common oil and gas lease may unilaterally surrender the entire leasehold, even as to the holders of other divided portions of the working interest, if the lease would otherwise be held by production.[33]

The Oklahoma Supreme Court did not attempt to answer the question directly. The court did not address directly whether the Staab release was effective as to all depths including the deeper zones held by Moore. Nor did it explain whether it is wrongful for a top lessee in Oil Valley's position to "washout" an overriding royalty interest or a working interest in a divided portion of a bottom lease by procuring the surrender of the bottom lease from a third-party leaseholder when the bottom lease continues to be held by production. Instead, the court reversed the trial court's

[33] *Oil Valley Petroleum*, ¶ 2.

entry of summary judgment on the grounds that it lacked a sufficient evidentiary record and remanded for further proceedings. The opinion expressly holds that (i) Moore's claim that the production in paying quantities from the Bell 1-24 preserved the Athan Lease despite the Staab release failed on summary judgment because no evidence existed in the record to show the well was profitable; (ii) an overriding royalty interest may be extinguished by a release of the underlying lease unless the release is the result of fraud or a breach of a fiduciary duty; and (iii) whether a party is a "prevailing party" for purposes of an award of attorney fees is a determination to be made by the trial court rather than an appellate court on review.[34]

The opinion first considers whether Moore was entitled to summary judgment on his claim that continued production from the Ball 1-24 held the shallow portion of the Athan Lease (in which he held an override) and the deeper portions of the working interest (which he owned). The opinion reaffirms the principle that the habendum clause is indivisible despite divisions in the leasehold as to subsurface strata. This principle was affirmed in *Rist v. Westhoma Oil Co.*, which held that payment of delay rentals by the owner of a divided interest in the shallow rights under an oil and gas lease is sufficient to continue the lease in its primary term as to the entire leasehold.[35] Under this principle, production from any formation or formations satisfies the habendum clause as to the leasehold in all formations. Thus, in principle at least, by producing from a shallow formation under the Athan Lease, the Ball 1-24 well could continue the lease as to Moore's deep rights.

The parties differed, however, as to whether Moore had established for summary judgment purposes that the production from the Ball 1-24 was in paying quantities. The summary judgment record contained evidence of Moore's receipts from his overriding royalty interest in production from the Ball 1-24, but Moore offered no documentation about the costs to operate the well on which the court could test whether the production was profitable. For this reason, the court "reversed the partial summary adjudication granted to Moore."[36] It should be noted that the posture of this case is unusual, as Moore, whose argument for the continuation of his deep rights rested on the continuation of production from the Ball 1-24, neither operated nor owned any working interest in the well. His only interest was an override. In all likelihood, Moore would not have had custody or control over evidence of the operating costs of the well.

Implicit in its ruling is the court's assumption that Moore bore the burden of production of evidence to support a finding that the Ball 1-24 was not producing in paying quantities. The burden of proof that a lease has terminated for lack of production ordinarily rests with the lessor challenging the validity of the lease.[37] In a typical case, the party in Moore's position might prevail on summary judgment by demonstrating that the plaintiff asserting lease termination had failed to offer affirmative proof to support a reasonable trier of fact in finding that the lease failed to produce in paying quantities. The opinion in this case frames Moore's position on summary judgment as "seeking to enforce the habendum clause against Oil Valley."[38] Although phrased in a manner that would suggest Moore carried the burden of production such a claim, it is not clear what it means

[34] *Id.* ¶ 0.
[35] 1963 OK 126.
[36] *Id.* ¶ 53.
[37] *See* Pack v. Santa Fe Minerals, 1994 OK 23, ¶ 30 (establishing that lessors bear the burden in showing a lease has terminated based on a cessation of production).
[38] *Id.* ¶ 36.

to "enforce the habendum clause" against a top lessee, other than to raise the continuing validity of the base lease as a defense to lease termination.

It is possible the court meant this in reference to Moore's affirmative claims against Oil Valley for procuring Staab's release of the Athan Lease.[39] Moore asserted counterclaims that in substance asserted that Oil Valley procured Staab's surrender of the Athan Lease to wrongfully washout Moore's override in the shallow rights and working interest in the deep rights. *Amicus curiae* filed a brief in support of Moore's position, urging the court to determine whether "a lessee of a base lease may file a release to extinguish an overriding royalty interest and other working interests in the base lease if circumstances of the release constitute a constructive fraud in equity." *Amici* and Moore argued that the release of a base lease that is otherwise producing in paying quantities to washout other interests in the lease constitutes constructive fraud.

On this point, the court held that a lessee is free to release an underlying oil and gas lease even if it extinguishes an overriding royalty interest, because "[t]he nature of an overriding royalty interest is such that it attaches only when oil and gas are reduced to possession. Before this, the owner of an overriding royalty has no assertable right in the leasehold and the vesting of such owner's rights are dependent on the happening of a future event or condition."[40] This conclusion is consistent with earlier cases, notably *De Mik v. Cargill*, where the court recognized an exception to this general rule for fraud and breach of a fiduciary relationship.[41] *De Mik* holds "that an overriding royalty was lost upon renewal of the oil and gas lease because, absent fraud or breach of a fiduciary relationship, the interest did not continue and attach to subsequent leases secured in good faith by the lessee."[42]

The court declined to answer whether it constituted "constructive fraud" for Staab to release the Athan Lease so that Oil Valley's top lease could take effect, because, it explained, the record on appeal did not establish whether the Athan Lease was producing in paying quantities at the time.[43] Concluding that "the trial court record is insufficient for adjudicating the issues concerning Moore's rights and duties as a lessee in the base lease on Moore's claim in equity that Oil Valley had unclean hands,"[44] the court remanded the case for further proceedings. It remains an open question whether a release of a producing lease to a top lessee to extinguish other interests in the bottom lease is a wrongful "washout."

Despite the unresolved fact questions, the legal issue presented in this case is interesting and potentially important. That issue seems to be two-pronged: First, whether a release of an oil and gas lease by the owner of the working interest in a divided portion of the leasehold is effective to release the leasehold as to other divided portions held in separate ownership. And second, whether and under what circumstances it might violate a duty owed to the holder of an overriding royalty interest in the lease or a divided portion of the leasehold working interest.

[39] *Id.* ¶ 89.
[40] *Id.* ¶ 64.
[41] 1971 OK 61.
[42] *Id.*
[43] *Oil Valley Petroleum*, ¶ 70.
[44] *Id.* ¶ 82.

As to the first part of the question, a typical surrender clause of an oil and gas lease purports to empower the lessee to "at any time and from time to time surrender this lease as to any part or parts of the leased premises by delivering or mailing a release thereof to lessor, or by placing a release of record in the proper County."[45] It is certain that the lessee of a portion of an oil and gas lease containing such a clause may release its interest in the lease pursuant to the clause's terms. More difficult is the issue of whether such an owner may surrender the entire leasehold premises, including separate divided portions held by other persons. To conclude that a lessee is empowered to do so would impermissibly expand the scope of the lessee's rights to include the power to relinquish the property interests of third parties. *Nemo dat quod non habet*—one cannot grant what one does not have. Thus, a release executed by one lessee of an oil and gas lease should not ordinarily operate to release the interests of another lessee owning a divided portion of the working interest.

Turning to the second part of the question, the surrenderor owes no general legal duty to the other owners of working interest in the lease to protect them from the consequences of the surrenderor's release. Owing to the indivisibility of the habendum clause, the release of one portion of an oil and gas lease will often affect the validity of other divided portions, particularly where the released portion contains the only producing well on the lease. This fact has not, however, persuaded courts that the surrenderor must abstain from exercising its right under the lease to surrender all or a portion of its holdings. The owner of working interest in a horizontally or vertically divided portion of a common lease generally has the right to develop the lease independently of other interest owners. Such an owner is in no way dependent on the efforts or good faith of the other divided working interest owners to maintain the lease by operations or production and is legally capable of protecting its own leasehold interests. Principle does not require a duty be implied between such parties.

Consider a similar case decided by the Texas Supreme Court, *Ridge Oil Co. v. Guinn Investments, Inc.*[46] Ridge and Guinn owned divided portions of a 1937 lease. Ridge operated the only well on the lease premises. In 1998, Ridge released its leasehold interest and acquired a new lease from the mineral owners under Ridge's portion of the 1937. Ridge then continued to operate its well under the new lease. As a consequence, Guinn's interest in the 1937 lease ceased to produce because the only well that previously held the lease was now located on a tract covered by Ridge's new lease. The court held that Ridge owed no duty to Guinn and it was immaterial that a collateral effect of Ridge's actions was to cause the 1937 lease to terminate of its own terms. Guinn had the right, independent of Ridge, to drill and produce its portion of the 1937 lease premises and thereby protect its interest from termination if production from Ridge's tract were to cease.[47]

The relationship is different between the holder of working interest in a lease and the owner of a nonoperating overriding royalty interest. In that case, the nonoperating owner has no right to develop the premises itself and therefore must depend on the working interest owner to enjoy the benefit of its interest. At the very least, the *Oil Valley Petroleum* opinion provides the rule that a working interest owner must not release a lease to terminate an overriding royalty interest out of fraud or in breach of an independent fiduciary duty. The opinion does not shine any light on what

[45] *Id.* ¶ 78.
[46] 148 S.W.3d 143 (Tex. 2004).
[47] *Id.* at 155.

might constitute fraud or constructive fraud. Case law in other jurisdictions has held that working interest owner's attempt to surrender a producing lease will be ineffective as to an overriding royalty interest.[48] This is potentially applicable in *Oil Valley Petroleum*, since the question of whether the well was continually producing remains open. Additionally, where the surrender is made in a collusive scheme been the working interest owner and the lessor of the oil and gas lease to eliminate the overriding royalty interest, Kansas courts employ equity to bar the release and impose a constructive trust in the new lease on behalf of the overriding royalty interest.[49]

III. The Oklahoma Supreme Court opines on the proper manner of dividing equity interests in oil and gas enterprises in a divorce proceeding, in Fitzpatrick v. Fitzpatrick, 2023 OK 81.

This was a divorce action involving a couple with significant marital assets in oil and gas. Husband appealed the trial court's final decree of dissolution of marriage pertaining to the division and distribution of the oil and gas assets. The Court of Appeals reversed, and the Oklahoma Supreme Court vacated the appellate opinion to reinstate the trial court's decision on all issues.

Husband owned Series A Units of equity in two different oil and gas exploration and production ventures, Flywheel Bakken and Flywheel Energy.[50] To purchase the Series A Units in Energy, husband made a partial capital investment and pledged his Series A Units in Bakken. He used marital assets in both purchases. In addition to his Series A Units, husband received Series B "profit" Units in both Bakken and Energy as an employee of the ventures. The Baken B Units were vested while the Energy B Units vested on a five-year schedule, "contingent on Wife's signature on a 'spousal consent form,' which Wife signed."[51]

The trial court found that all the units were acquired during the marriage through the joint efforts of husband and wife and were marital property subject to division. Given that the value of the property was tied to the growth of the ventures, the trial court determined the most equitable form of division would be to order husband to hold future distributions and proceeds from the units in constructive trust for the benefit of both parties and to distribute the wife's equal share to her.[52]

Husband argued on appeal that the trial court erred in finding that the Energy A and B Units to be marital property, in assigning value to the units, and in ordering future proceeds from the units to be distributed in constructive trust. The Court of Appeals reversed the trial court's findings on the Energy A and B Units, holding that the trial court should have determined their value and set a valuation date rather than order a constructive trust.[53]

The Supreme Court affirmed the trial court's order deferring distribution of the unvested Energy A and B Units, holding that when faced with an asset "the value of which could not be determined at the time of property division," trial courts should use a deferred distribution method,

[48] 5 KUNTZ, LAW OF OIL AND GAS § 63.2 (citing Cain v. Neumann, 316 S.W.2d 915 (Tex. Civ. App. 1958); In re GHR Energy Corp., 972 F.2d 96 (5th Cir. 1992)).
[49] *Id.* (citing Campbell v. Nake Corp. 402 P.2d 771 (Kan. 1965)).
[50] The opinion is not explicit, but it appears the entities were LLCs and the equity units were units of membership interest.
[51] Fitzpatrick v. Fitzpatrick, 2023 OK 81, ¶¶ 4–5.
[52] *Id.* ¶ 6.
[53] *Id.* ¶ 8.

rather than attempt to value the assets at present.[54] This was true even for the Energy A Units that were not subject to vesting or the contingency of wife's consent, because like the other units, most of their value depended on the growth potential of the underlying venture.

The court also affirmed the trial court's characterization of the Energy B Units (which husband received in connection with his employment) as a marital asset subject to division. It is presumed that all property acquired during the marriage is marital property and the record supported the trial court's finding that husband failed to rebut the presumption.[55]

Finally, the court affirmed the imposition of a constructive trust on all the units. The Court of Appeals reversed on this point, citing a lack of any express authority in Oklahoma statutes to impose a constructive trust in dividing marital assets. The court disagreed, noting that it had approved decrees in previous cases requiring the owning spouse to maintain assets for both spouses' benefit after divorce and reiterating the wide discretion vested in trial courts to divide marital assets.[56] The constructive trust was justified in this case by husband's past failures to properly discharge his fiduciary duties and the importance, therefore, of avoiding his unjust enrichment at wife's expense.[57]

IV. The Oklahoma Court of Civil Appeals affirms order certifying a class action suit alleging breach of the implied duty to market based on a lessee's deduction of costs of removing natural gas liquids (NGLs), in Hitch Enters., Inc. v. Key Prod. Co., No. 119,052 (Okla. Ct. App. Dec. 30, 2022) (cert denied Oct. 16, 2023).

This is an appeal of a trial court's order granting the plaintiff's motion to certify a class in its suit against the defendant oil and gas lessee. The plaintiffs allege that the defendant breached its implied duty to market and the marketable product doctrine by deducting from the royalty paid to class members the costs of removing natural gas liquids (NGLs) from the gas extracted from class wells. These costs, argue the plaintiffs, are necessary to render a marketable product.

The defendant objected to certification on the ground that no issue common to the class predominates over individual issues for two reasons: (i) it is a fact-intensive inquiry whether gas from any of the over 300 wells at issue required processing to be rendered marketable, and (ii) the proper calculation of royalty owed under each of its oil and gas leases with members of the class is to be determined on a lease-by-lease basis, given the particular language of each lease's royalty clause, as well as defendant's individual gas sales contracts.

In affirming the trial court's order, the Court of Appeals found that the particular quality and composition of the gas from each of the wells at issue did not create individualized issues of fact. The defendant gathered the gas from all the class wells and delivered it to a third-party midstream company at a common gathering point. From there, the midstream company transported and processed the gas for downstream sales in the interstate market. Because the gas from all wells was commingled in the defendant's gathering system, it could not be shown what, if any, degree

[54] *Id.* ¶ 11–12.
[55] *Id.* ¶¶ 17–18.
[56] *Id.* ¶¶ 19–20.
[57] *Id.* ¶ 21.

of gathering, compression, transportation, dehydration, or processing might have been necessary to render gas from any individual well marketable. The lack of available evidence on this point rendered the importance of the gas quality from each well moot, not because it is not relevant to whether the defendant breached its implied duty, but because it was impossible to litigate the issue on an individual basis.[58] Litigation on a class-wide basis was thus appropriate.

Additionally, the court was unpersuaded that any differences in the royalty language of the over 3,000 leases at issue could matter in determining whether the defendant breached the implied duty to market. The defendant showed that the leases at issue contained a variety of different royalty clauses, including clauses that required that royalty be calculated on "proceeds," "at the well," on the value of the "raw gas" or gas in its "natural state," and based on the value of "arms-length transactions."[59] The defendant cited Dean Kuntz's treatise for the proposition that class certification is improper where royalty provisions vary as to type.[60] The court reasoned, however, that the royalty clauses at issue do not vary as to type because they all give rise to the implied duty to market. Thus they are all subject to the same duty to render a marketable product, regardless of how or at what point the express language would otherwise require the royalty be calculated.[61]

The differences are irrelevant, the court explained, because "if all of the Class leases are subject to the implied covenant to market, and [defendant] breached that covenant by charging Class members for processing costs, it does not matter what individualized language in an individual lease gave rise to the implied covenant to market."[62]

This kind of categorical reasoning was possible because the plaintiffs had carefully excluded from the proposed class any members whose oil and gas leases contained language that explicitly spelled out the lessor's agreement to share in certain costs of gathering, compression, dehydration, transportation, and processing.[63] Yet, it is noteworthy how easily the Court of Appeals dismissed any possibility that standard language calling for royalty to be calculated on "actual proceeds," based on the value of "raw gas" or "gas in its natural state," or "at the well" does not displace the implied duty. Most of these provisions existed in some form in the leases at issue in the trilogy of cases establishing Oklahoma's marketable product rule, and thus have implicitly, at least, been found not to abrogate the common law rule.[64] The tolerance of Oklahoma courts for arguments to the contrary, which prevail in states like Texas and even Kansas, which also follows the marketable product rule,[65] appears to be low indeed.

Now that the class is certified, the case will proceed in the trial court for adjudication on the merits. Those merits, the Court of Appeals explained, turn on "[w]hen gas extracted from Class wells became marketable."[66] Should this case return to the appellate courts following a merits

[58] *Hitch Enters.*, ¶¶ 45–48.
[59] *Id.* ¶ 49.
[60] 3 KUNTZ, LAW OF OIL & GAS § 40.4(a).
[61] *Hitch Enters.*, ¶ 54.
[62] *Id.* ¶ 50.
[63] *Id.* ¶ 55.
[64] This is the *Mittlesteadt* trilogy of cases: Mittelstaedt v. Santa Fe Minerals, Inc. 1998 OK 7; TXO Prod. Corp. v. State ex rel. Comm'rs of the Land Office, 1994 OK 131; Wood v. TXO Prod. Corp., 1992 OK 100.
[65] *See* Fawcett v. Oil Producers, Inc. of Kansas, 352 P.3d 1032, 1039 (Kan. 2015).
[66] *Hitch Enters.*, ¶ 60.

ruling, it might provide needed clarification on the legal standard for determining this very issue. As the next case discussed demonstrates, what Oklahoma requires for natural gas to be "marketable" remains unsettled. Although the Court of Appeals did not need to pass on the applicable legal standard in this opinion, it did summarize three recent cases that bear on the issue.

In *Whisenant v. Strat Land Exploration Co.*, the court recognized that determining when gas has been rendered "marketable" in satisfaction of the implied duty to market may involve complex, fact-intensive inquiries.[67] In particular, in that case, the court decided that the composition and quality of gas produced from the relevant wells were necessary factors for determining when a first marketable product was obtained. That was because the lessee's gas contracts determined the sale price for gas based on "the measurements and analysis done on the gas produced from each individual well at the wellhead."[68] For this reason, it denied class certification because individualized gas-quality inquiries predominated.

In *Plummill v. Hancock Exploration, LLC*, the court focused the marketability inquiry on the requirements of the market for the gas that was chosen or intended by the lessee.[69] Thus, the relevant inquiry is twofold: (i) what market was intended and (ii) what are the requirements for the condition of natural gas or natural gas products to be sold in that market? The individualized inquiry into the quality of natural gas from particular wells is suggested to be unnecessary in this analysis.[70]

Finally, in *Naylor Farms, Inc. v. Chapparal Energy, LLC*, the 10th Circuit Court of Appeals examined *Whisenant* and *Pummill* to predict that Oklahoma law would hold that marketability could be determined "based solely on expert testimony that all the gas at issue was required to undergo at least one GCDTP [gathering, compression, dehydration, transportation, or processing] service before it could 'reach' and be 'sold into' the pipeline market."[71] Key to this conclusion is the premise, from *Plummill*, that the definition of marketability depends on the requirements of the particular market chosen by the lessee for its gas. If expert testimony indicates that the interstate pipeline market was intended, then any GCDTP services required to meet the requirements of that market would be a *per se* requirement of marketability.

PART TWO
OKLAHOMA TRIAL-LEVEL CASES

I. State trial court rules that the marketable product doctrine requires lessee to incur all costs associated with transportation and fractionation of NGLs from a gas stream despite transferring title and custody to the gas in the field under a netback pricing contract, in Nash Family Mineral Trust UTA dated October 27, 1992, v. Merit Energy Company, LLC, No. DF-121355 (Texas Cnty. D. Ct. May 10, 2023) (appeal filed).

Plaintiff lessors sought a declaratory judgment that the cost of making natural gas liquids into marketable products is a cost of production that must be borne exclusively by the lessee under

[67] 2018 OK CIV APP 65.
[68] *Id.*
[69] 2018 OK CIV APP 48.
[70] Naylor Farms, Inc. v. Chapparal Energy, LLC, 923 F.3d 779, 795 (10th Cir. 2019).
[71] *Id.*

Oklahoma's marketable product doctrine. Following a four-day bench trial, the district court for Texas County ruled that the reasoning of *Mittelstaedt* and its progeny require a lessee to pay royalty on the downstream price of purified NGL commodities even where the lessee transferred title and custody to the raw gas to a third-party midstream company upstream of the gas processing plant.

Although the defendant lessee's arrangements differed somewhat at earlier times, starting in 2021, the defendant began selling its gas on the Hugoton Gas System to DCP Midstream. Under this arrangement, the defendant delivers its gas to DCP at the Liberal Receipt Point. Downstream of that point, DCP transports and processes the gas. After processing, the "raw mix" of liquids are usually transported on DCP's pipeline to either Mont Belviu, Texas or Conway, Kansas for fractionation into pure commodity products and ultimate sale. DCP pays the defendant for the raw mix based on a commercial price index for each NGL commodity, less DCP's costs of transportation and fractionation (T&F). Defendant calculates royalties on NGLs based on the proceeds it receives from DCP, less the defendant's costs incurred between the wellhead and the Liberal Receipt Point, to arrive at a netback "wellhead price."

The defendant first asserted that the language of the royalty clauses in its oil and gas leases requires that the royalty be calculated on the market value of the gas at the wellhead. This was found in the "market price at the well" phrase in some leases, the "market value at the well" language in others, and the "proceeds from the sale of gas, as such" language in still other leases. Rejecting this contention on the ground that the *Mittelstaedt* trio of cases recognizing the marketable product doctrine involved leases containing similar language, the court ruled that defendant's leases did not negate its implied duty to market the gas at its sole cost.

Next, the defendant contended that it satisfied its obligation to place the NGLs into a marketable condition at its sole cost when it sold the gas stream at the Liberal Receipt Point. The court rejected this argument, reasoning that these transactions were not true sales, since the price paid for the gas was based on a netback pricing formula that deducted processing costs from an index price representing the value of downstream transactions. "There is not a true market for the gaseous hydrocarbon stream at the wellhead. There is a difference between the concepts of 'saleable' and 'marketable.'"[72]

To the court, the defendant impermissibly deducted from the plaintiffs' royalty the costs of T&F for the NGLs by calculating the royalty on the basis of the proceeds it actually received under its netback contract with DCP. The T&F costs are necessary to render NGLs "marketable" and thus cannot be deducted from the royalty share.[73] By this logic, any percent-of-proceeds (POP) or percent-of-index (POI) contract for the sale of raw gas in the field or at the wellhead would violate the duty to market by implicitly "deducting" costs that the lessee could not deduct from the royalty directly.

The court relied heavily on the 2018 Court of Civil Appeals decision in *Pummill v. Hancock Exploration, LLC*.[74] That case involved a similar gas sales contract, whereby the lessee delivered gas from the wellhead to a third party's gathering system at a transfer point in the field, downstream

[72] *Nash Fam. Min. Tr.*, at 5.
[73] *Id.* at 17.
[74] 2018 OK CIV APP 48.

of which the gas was transported, processed, and sold in the interstate market. *Pummill* affirmed the trial court's factual finding that gas was not marketed at the point where it was transferred from the lessee to the third party and did not become marketable until a point after processing when the gas was in a condition that was saleable in the interstate market.

Pummill declined to adopt a definition of marketability that the Kansas Supreme Court adopted in a recent similar case, *Fawcett v. Oil Producers, Inc. of Kansas*, *i.e.*, that "production is merchantable once the operator has put it into a condition acceptable to a purchaser in a good faith transaction."[75] Instead, it found *Fawcett* "factually distinguishable in that the first, *actual sales of gas occurred at the wellhead*, and the lease language clearly made reference to royalties measured by sales 'at the mouth of the well' or 'if sold at the well' in contrast to the 'gross proceeds' language at issue here."[76] This is telling. The key fact found by the trial court in *Pummill* seems to be that the lessee defendants failed to produce any evidence that they made an "actual sale" of gas until the gas reached the tailgate of a processing pipeline or an interstate pipeline.[77] Thus, *Pummill* does not appear to hold that a wellhead sale of gas under a netback pricing formula could never satisfy the marketable product rule, but only that a transfer of custody of gas in the field to a third-party midstream company does not necessarily constitute an "actual sale" as automatically as it would in Kansas under *Fawcett*.

The question that remains open after *Pummill* is this: What is the definition of a "marketable product" under Oklahoma law? *Pummill* suggests that marketability is a fact-intensive question, not only about the quality of the gas but also about the market the lessee has chosen to put the gas into. Thus, although the lessee physically transferred custody of the gas to the third-party midstream company at a point in the field, this did not constitute a sale of the gas because the lessee was not participating "in the wellhead market" but rather in the "pipeline market," which is to say the interstate market.[78] *Pummill* endorsed the trial court's focus on the market that was chosen or intended for the gas by the lessee to define the requirements of marketability:

> The trial court's decision focused on the undisputed evidence that the market in which Defendants have chosen to participate, and the first, *actual sale* of gas from the 1-32, does not in fact occur until after the gas is further compressed, treated, dehydrated, separated, and processed so that it is acceptable for transport in high-pressure pipelines.[79]

The "intended market" formed the basis of the 10th Circuit's recent decision on class certification in *Naylor Farms*.[80] That court distilled the question into two sub-issues: "(1) what market did the lessee choose to participate in and (2) what must be done to the gas product to make it acceptable for the market."[81]

[75] 352 P.3d 1032, 1034 (Kan. 2015).
[76] 2018 OK CIV APP 48, ¶ 44.
[77] *Id.* ¶ 32.
[78] *Id.* ¶ 36.
[79] *Id.* ¶ 38.
[80] Harrel's LLC v. Chaparral Energy, LLC (Naylor Farms, Inc.), 923 F.3d 779 (10th Cir. 2019).
[81] *Nash Family Mineral Trust*, at 22 (citing *id.* at 792–94).

Applying the intended-market theory, the trial court in *Nash Family Mineral Trust* concluded that there is no market for NGLs at the wellhead and, therefore, the only market must be downstream after transportation and fractionation. Persuaded by the testimony of plaintiff's expert witness about the economic definition of a "market," the court found that no market existed before this downstream point because (i) the raw mix is not a fungible product, like a stream of methane, until fractionation, (ii) there are few buyers (market participants) of raw mix—in fact, only DCP in the present case—until fractionation, (iii) there is no reliable price index for raw mix, but only for fractionated NGL commodities, and (iv) entry into the "wellhead market" is difficult, as opposed to entry into the downstream market for fractionated commodities. The fact that the netback pricing formula in the defendant's contract with DCP referenced index prices for downstream sales of NGL commodities, the court found, is further evidence that no market exists for NGLs upstream of fractionation.[82]

Based on these factors, the court found that markets exist for NGLs at Mont Belvieu, Texas and Conway, Kansas, but not upstream of those points. The defendant "chose" the Mont Belvieu market and thus was responsible for all T&F expenses necessary to sell NGLs at that point.

The defendant filed its appeal in *Nash Family Mineral Trust*, seeking review on nearly twenty issues. Boiled down, the most pressing questions seem to be these: (i) Does the implied duty to market, and thus its corollary the marketable product doctrine, apply to require a lessee to fractionate NGLs into pure commodity products following processing of the natural gas stream? (ii) When, if ever, may a contract with a third-party midstream provider transferring physical custody of and title to natural gas at a point in the field, near the wellhead, constitute an "actual sale" of the gas satisfying the marketable product doctrine? (iii) Does Oklahoma law define marketability with reference to the market intended or chosen by the lessee and, if so, what is the standard for determining what the intended market is in any given case? And (iv) is lease language requiring royalty to be paid on a fraction of "the actual amount received by the lessee" from the sale or use of gas off the lease, as such, sufficient to displace the marketable product doctrine in a case like this?

II. Jury finds operator liable for nuisance and negligence in frac-interference case in Kingfisher County leading to appeal of legal issues, in Gulf Exploration, LLC v. Okla. Energy Acquisitions, LP, Case No. CJ-2019-63 (Kingfisher Cnty. Oct. 3, 2022) (appeal filed).

Plaintiffs owned leases and held permits from the Oklahoma Corporation Commission to drill and produce oil and gas from the Hunton and Woodford formations in which they drilled and completed the Caldwell 1-14 H well. Defendant owned leases and held permits from the OCC to drill and produce oil from the Hunton, Woodford, and Mississippian formations in which it drilled and completed using hydraulic fracturing eight wells. Plaintiffs sued for trespass, negligence, and nuisance, alleging that defendant negligently fracked its wells so as to impermissibly frack into the Mississippian formation and cause fluids to communicate between the Woodford and Mississippian formations. This allegedly caused a decline in production from the plaintiffs' Caldwell 1-14H well as well as contamination in the well from foreign fracking fluids.

[82] *Nash Family Mineral Trust*, at 26.

Following a two-day trial, the jury returned a verdict in favor of plaintiffs on their claims of nuisance and negligence, but not on their claim of trespass. The jury found the plaintiff suffered $2,000,000 in damages from the nuisance and $2,000,000 in damages from the defendant's negligence, discounted to reflect the jury's finding that the plaintiff was 20% at fault. The court entered judgment against defendant on October 3, 2022, and the defendant timely appealed.

The issues raised on appeal are (1) whether the trial court erred in admitting evidence of other fracking lawsuits filed against the defendant in Kingfisher County, and (2) whether the trial court erred in refusing to direct a verdict in favor of defendant because the plaintiff failed to adduce evidence sufficient to establish causation.

PART THREE:
OKLAHOMA FEDERAL CASES

I. The District Court for the Western District of Oklahoma interprets Oklahoma's anti-indemnity statute not to apply to a cross-indemnity agreement in a master service agreement, in Chesapeake Operating, LLC v. C.C. Forbes, LLC, 2023 WL 2879516, 2023 U.S. Dist. LEXIS 63761, __ F.3d __ (W.D. Okla. 2023) (appeal filed with 10th Circuit on April 10, 2023).

In this case, the Western District of Oklahoma decided whether, as a matter of law, C.C. Forbes, LLC (Forbes) was contractually obligated to indemnify plaintiff Chesapeake Operating (Chesapeake) under the parties' Master Service Agreement (MSA) for amounts Chesapeake contributed to the settlement of a personal injury claim brought by one Forbes's employees arising at a Chesapeake well site.

Chesapeake alleged that Forbes refused to indemnify Chesapeake for the $1.68 million plus $168,528.96 in fees and costs it contributed to settling the matter. Forbes contended that the indemnity provision was either void under Oklahoma law, if Oklahoma law applied, or that its liability was capped at $1 million if Texas's Oilfield Anti-Indemnity Act applied. As an initial matter, the court determined that Oklahoma law applied according to the MSA's express choice of law provision.[83]

The relevant indemnity provision of the MSA is set forth in paragraph 60 as follows:

> [Forbes] agrees to protect, defend, indemnify and hold harmless [Chesapeake], its officers, directors, employees or their invitees, and any working interest owner or non-operator for whom [Chesapeake] is obligated to perform services, from and against all claims, demands, and causes of action of every kind and character without limit and without regard to the cause or causes thereof or the negligence or fault (active or passive) of any party or parties including the sole, joint or concurrent negligence of [Chesapeake], any theory of strict liability and defect of premises . . . arising in connection herewith in favor of [Forbes's] employees, [Forbes's] subcontractors or their employees, or [Forbes's] invitees on account of bodily injury, death or damage to property.[84]

[83] *Chesapeake Operating*, at *8.
[84] *Id.* at *2.

Forbes was also obligated under the MSA to maintain commercial general liability insurance on an occurrence basis for no less than $1 million per occurrence.

Title 15, Section 221, subsection (B) of the Oklahoma Statutes limits the use of indemnity agreements in construction contracts. It states:

> [A]ny provision in a construction agreement that requires an entity or that entity's surety or insurer to indemnify . . . another entity against liability for damage arising out of death or bodily injury to persons, or damage to property, which arises out of the negligence or fault of the indemnitee, its agents, representatives, subcontractors, or suppliers, is void and unenforceable as against public policy.

An agreement to indemnify is defined by statute as "a contract by which one engages to save another from a legal consequence of the conduct of one of the parties, or for some other person."[85] A "construction agreement" is defined as "a contract, subcontract, or agreement for construction, alteration, renovation, repair, or maintenance of any . . . structure. . ., or other works dealing with construction, or for any moving, demolition, excavation, materials, or labor connected with such construction."[86]

Forbes asserted that the MSA's indemnity provisions fell under Section 221. It argued that an oil and gas well is a "structure" and that the underlying personal injury that occurred to its employee while working on Chesapeake's well occurred in the course of alteration, repair, or maintenance of the oil well. Forbes based its interpretation on Black's Law Dictionary's definition of "structure" as "a piece of work artificially built up or composed of parts purposefully joined together," which Forbes argued describes an oil and gas well. Furthermore, Forbes raised another Western District opinion, *Jet Maintenance, Inc. v. Devon Energy Production Co., L.P.*,[87] as persuasive authority for the proposition that oilfield services may constitute construction work. There, the court applied Section 221 to void the parties' MSA and relieve the service company from its indemnity obligation to the production company after a truck carrying aggregate rock struck and killed a man at the wellsite. The aggregate was used to build a well pad in preparation for a drilling rig. The district court in *Jet Maintenance* relied on Black's Law Dictionary to find that a drilling rig was a "structure" within the meaning of Section 221.

The court disagreed based both on the text and the legislative history of Section 221. To construe the text of the statute, the court employed the plain meaning canon and held that the plain meaning of "well," being "[a] hole or shaft sunk into the earth to obtain a fluid, such as water, oil, or natural gas," is not ordinarily understood as a "structure."[88] Moreover, the court then employed the canon of construction, *noscitur a sociis*, which "instructs that an unclear word 'should be determined by the words immediately surrounding it.'"[89] The other words surrounding "structure" in the definition of "construction contract" include "building, building site, structure, highway,

[85] OKLA. STAT. tit. 15, § 421.
[86] OKLA. STAT. tit. 15, § 221(A).
[87] No. CIV-22-263-C, 2022 U.S. Dist. LEXIS 103199, 2022 WL 2079886 (W.D. Okla. June 9, 2022).
[88] *Chesapeake Operating*, at *11 (citing Black's Law Dictionary (11th ed. 2019)).
[89] *Id.* (quoting Black's Law Dictionary (11th ed. 2019)).

street, highway bridge, viaduct, water or sewer system." None of these, concluded the court, suggest that the word "structure" was meant to encompass an oil and gas well.

The court bolstered its textual interpretation with the legislative history of Section 221. According to the opinion, an earlier version of Section 221 would have expressly covered indemnity agreements in oil and gas drilling service contracts, but that this language was removed from the bill before its passage. One year later, legislators introduced a bill that would have extended the effect of Section 221 to cover agreements pertaining to oil and gas wells. This bill failed. Taken together with the amendment of the prior version of Section 221, this failed bill suggested to the court that the legislature did not intend Section 221 to include contracts involving oil and gas wells.[90]

Having concluded that Section 221 does not void indemnity agreements in oilfield service contracts, the court went on to order Forbes to "indemnify Chesapeake in the amount of $1,848,528.96, which constitutes the amount Chesapeake contributed to the settlement agreement including legal fees related to the settlement."[91]

II. The District Court for the Eastern District of Oklahoma requires something more than trace amounts of petroleum contamination for nuisance liability, in Lazy S Ranch Props., LLC v. Valero Terminaling & Distrib. Co., Case No. 19-CV-425-JWB, 2022 WL 17553001, 2022 US Dist. LEXIS 222116 (E.D. Okla. Dec. 7, 2022) (appeal filed Mar. 22, 2023)

The plaintiff sued defendant, a pipeline operator, for soil, water, and air contamination from defendant's leaking pipeline. The defendant moved for summary judgment on the ground that the evidence showed only trace elements of refined petroleum products on plaintiff's property, well below any regulatory levels or even the levels at which the lab testing the samples felt comfortable reporting the existence of contaminates. The plaintiff also moved for summary judgment arguing that *any* level of contamination violated its rights. On summary judgment, the court held that under Oklahoma law "a plaintiff must establish that the alleged contaminants exist in sufficient quantities to constitute a nuisance or to render the environment harmful, detrimental, or injurious."[92] The court entered summary judgment for the defendant because no reasonable trier of fact could find that such trace amounts of contamination would satisfy this standard, and also because the record contained no evidence to establish that defendant was the proximate cause of the contamination.

Plaintiff then moved to alter or amend judgment.[93] The plaintiff's primary legal argument was that the court committed clear error in interpreting Oklahoma law to require contamination to rise to the level of a nuisance or cause other harm to be actionable, in light of Oklahoma's Constitution. Article 2, Section 23 of the Constitution provides that "[n]o private property shall be taken or damaged for private use, with or without compensation." The court explained, however,

[90] *Id.* at *12–14.
[91] *Id.* at *15.
[92] *Id.* at *4.
[93] Lazy S Ranch Props., LLC v. Valero Terminaling & Distrib. Co., Case No. 19-CV-425-JWB, 2023 US Dist. LEXIS 36622, *2 (E.D. Okla. Mar. 2, 2023).

that the case law interprets Article 2, Section 23 as protecting landowners only from "substantial injury or unreasonable interference" with their property.[94]

Next, the plaintiff contended that the court misinterpreted a provision of Oklahoma's Environmental Quality Code defining "pollution" as "the presence in the environment of any substance," and any "alteration of the physical properties of the environment."[95] The court rejected this interpretation as absurd, since it would seem to encompass even harmless substances, like water, and harmless or beneficial acts, like pulling weeds. In fact, the definition read in its entirety makes it clear that only substances or alterations that are or may become a nuisance or are otherwise harmful or injurious to the public health may constitute "pollution."[96]

The plaintiff also contended that the court erred in considering maximum levels for contaminants set by administrative law. The court explained that regulatory levels are not dispositive of whether contamination constitutes a private nuisance, but they are relevant to the question of what levels of contamination are likely to cause interference or harm. Moreover, the plaintiff failed to produce any evidence that could persuade a reasonable trier of fact to the contrary.

III. The District Court for the Eastern District of Oklahoma holds that interest may be included in determining the amount in controversy where principal claim is for unpaid interest on royalties under the Production Revenue Standards Act, in Colton v. Continental Resources, Inc., Case No. CV–22–208–RAW–JAR, 2023 WL 6614426, 2023 U.S. Dist. LEXIS 184877 (E.D. Okla. Sept. 1, 2023).

This is a putative class action alleging that defendants failed to timely pay royalties and interest on the late payments as required by the Oklahoma Production Revenue Standards Act (PRSA). This opinion resolves a motion to dismiss the action for lack of subject matter jurisdiction under the Class Action Fairness Act (CAFA). Curiously, the motion was filed by the plaintiff against his own complaint. Despite alleging in the complaint that the amount in controversy exceeds $5 million, sufficient to support its claim of diversity jurisdiction under CAFA, the plaintiff moved to dismiss after counsel learned of a 2015 10th Circuit Court of Appeals opinion, *Whisenant v. Sheridan Production Co., LLC*,[97] that caused it to recalculate the amount in controversy.

Whisenant involved a class action alleging impermissible deductions of production costs from lessor royalties. The plaintiffs alleged diversity jurisdiction based on an amount in controversy in excess of $5 million, which included interest that they argued would be due on the unpaid royalties. The 10th Circuit held that CAFA's amount in controversy requirement must be determined "exclusive of interests and costs."[98]

[94] *Id.* at *8.
[95] *Id.* at *9.
[96] OKLA. STAT. ANN. 27A § 2-1-102(12).
[97] 672 Fed. App'x 706 (10th Cir. 2015).
[98] *Colton*, at *5.

The court in *Colton* distinguished *Whisenant*. Unlike the claim in *Whisenant* that the defendant failed to pay royalties that were due, the primary amount in controversy in *Colton* was the interest allegedly owned under PRSA. As the court explained, "[i]f the amount in controversy itself is the failure to pay interest, this amount would be included in the amount in controversy calculation for purposes of the CAFA."[99]

IV. 10th Circuit Court of Appeals grants appeal of $155 million damages award entered in 2019, in Cline v. Sunoco, Inc. (R&M), No. 22-7018 (10th Cir. Aug. 3, 2023).

This is an appeal of a District Court for the Eastern District of Oklahoma ruling in a class action suit against Sunoco by mineral interest owners claiming underpayment of interest on late payments under Oklahoma law. The mineral owners claimed that Sunoco adopted an unlawful practice of paying interest on late proceeds payments only when owners requested it. After certifying a class of some 53,000 interest owners, the district court found Sunoco liable after a bench trial and thereafter awarded $155 million in total damages, actual and punitive, to the class on their claims.

To appeal a judgment in a class action, 10th Circuit precedent requires that the judgment both (i) contain a formula to determine the division of damages among class members and (ii) identify the principles that will guide the disposition of any unclaimed funds. When Sunoco appealed the district court's entry of judgment, the appeal failed for lack of jurisdiction because the district court had not yet entered an order satisfying these two requirements of finality. The district court subsequently entered an order that provided for a method of division and that unclaimed funds would be forwarded to the state unclaimed property funds. Sunoco appealed this order, as well, but in the course of its appeal argued that the order did not satisfy the finality requirements for a number of reasons. Sunoco asked the 10th Circuit to treat its appeal as a mandamus petition and proposed an amendment to the district court's allocation plan. That appeal was eventually denied on the ground that Sunoco was not entitled to mandamus relief.

Following its second unsuccessful attempt at appeal, Sunoco filed a Federal Rule of Civil Procedure 60(b)(6) motion in the district court. FRCP 60(b)(6) empowers a court to, on a motion and just terms, relieve a party from a final judgment, order, or proceeding for any unenumerated reason that justifies relief. In that motion, Sunoco asked the district court to modify its allocation plan along the lines that it had requested in its mandamus petition at the 10th Circuit, because the district court's plan did not satisfy the two-pronged requirements for finality. The district court denied the motion, maintaining that the allocation plan complied with the finality standards as is. Sunoco then appealed again.

First, the 10th Circuit found that the district court's denial of Sunoco's 60(b)(6) motion was an appealable final order even though the motion itself was premised on Sunoco's argument that the underlying judgment was not itself final and appealable. Reviewing courts reverse an order denying relief under 60(b)(6) only if they find a complete absence of a reasonable basis for the decision and that the decision is wrong. The 10th Circuit thus reviewed whether the district court's plan of allocation indeed satisfied the two requirements of finality.

[99] *Id.* at *6.

The first finality requirement was not met because the plan of allocation adopted by the district court did not provide for how damages would be divided among mineral interest owners who Sunoco was unable to locate and for whom it has no address. Sunoco accounts for the proceeds payable to such owners by placing the proceeds into one of two aggregate accounts that are not assigned to any particular owner. Thus, the district court's plan of division, which made use of Sunoco's internal accounting mechanisms to identify owners, did not in fact provide any mechanism by which to divide up the funds that would be payable to those two aggregate accounts.

The second finality requirement also was not met because the district court's order simply deferred the question of how to dispose of any unclaimed funds to a later date. The district court decided to wait to determine that issue until it had distributed the funds that were claimed. It "anticipated" that it would send any unclaimed funds to "state accounts for unclaimed property" but retained discretion to select a different method once more information became available.[100]

Thus, the 10th Circuit reversed the district court's denial of Sunoco's 60(b)(6) motion. Because the district court's error was based on its erroneous conclusion that its allocation plan was final, the court remanded "for the district court to reconsider Sunoco's motion."[101] "We note, however, that the necessary consequence of our analysis is that the district court has yet to enter a final judgment. So although we do not yet decide whether Rule 60(b)(6) relief is appropriate, we urge the district court to promptly take whatever steps it deems necessary to cure the allocation plan's defects and produce a final judgment that complies with our precedents."[102]

PART FOUR: TEXAS APPELLATE DECISIONS

I. The Texas Supreme Court holds that 1/8 when used in a conveyance or reservation of a mineral interest refers to the entire mineral estate unless language in the instrument rebuts the presumption, in Van Dyke v. Navigator Grp., 668 S.W.3d 353 (Tex. 2023).

Before the court was a 1924 real property conveyance from Mulkey to White containing the following mineral reservation: "It is understood and agreed that one-half of one-eighth of all minerals and mineral rights in said land are reserved in grantors, Geo. H. Mulkey and Frances E. Mulkey, and are not conveyed herein."[103] Successors to the Mulkeys claimed 1/2 of the entire mineral estate while the White successors contended that the Mulkeys reserved only a 1/16 interest. The opinion provides an extended review of Texas jurisprudence on instrument interpretation, in which the court emphasize the importance of both harmonizing all the provisions in the document and interpreting the words in light of the objective meaning they would have held to the parties to the instrument at the time of its execution.

In light of these principles, the issue before the court came down to whether the parties intended "one-half of one-eighth of all minerals" to require multiplication of the two fractions to render an interest of 1/16 or, alternatively, whether the fraction 1/8 should be understood to refer

[100] *Cline*, at 15–16.
[101] *Id.* at 17.
[102] *Id.* at 17–18.
[103] *Van Dyke*, 668 S.W.3d at 357.

to the entire mineral estate. Despite the importance of constraining the interpretive inquiry to the four corners of the document, the court explained that the fraction 1/8 held peculiar significance to parties during much of the twentieth century that justifies a court in *presuming* that 1/8 refers to the entire mineral estate when used in conjunction with a second fraction, as in the reservation *sub judice*. This presumption is based on two misconceptions that, the court decides, were common at the time. First, that the lessor of an oil and gas lease believed mistakenly that it retained, during the life of the lease, only 1/8 of the mineral estate, when in truth it retained a 1/8 royalty together with the possibility of reverter in the entire mineral estate conveyed. Second, that the 1/8 royalty, which was standard to the point of ubiquity for much of the century, would always and necessarily remain the fractional royalty under a lease. Together, these two misconceptions meant that use of 1/8 in a mineral conveyance or reservation often referred to entire mineral interest.

The court further held that this presumption is not absolute. It may be rebutted by other language in the instrument indicating a contrary meaning. The court was careful to note that evidence to rebut the presumption should come only from the four corners of the document itself; the presumption does not justify admitting extrinsic evidence to rebut it.

Finally, the court bolstered its conclusion that the Mulkeys reserved 1/2 of the mineral estate, rather than 1/16, on an alternative theory: the doctrine of presumed grant, otherwise known title by circumstantial evidence. The doctrine has three elements, which the proponent must establish: (1) a long-asserted and open claim, adverse to that of the apparent owner; (2) nonclaim by the apparent owner; and (3) acquiescence by the apparent owner in the adverse claim."[104] The court found the Mulkey parties had acquired title to 1/2 of the minerals by presumed grant, even if this was not the intent of the original 1924 deed reservation. It cited a 99-year history in which *both* sides—the Mulkeys and the Whites—acted as though each owned 1/2 of the minerals through the execution of conveyances, leases, ratifications, division orders, contracts, probate inventories, "and a myriad of other documents that provided notice."[105]

II. The Texas Supreme Court interprets a lease addendum to create a "proceeds-plus" royalty lease, in Devon Energy Production Company, L.P. v. Sheppard, 668 S.W.3d 332 (Tex. 2023).

This case involved the interpretation of "a bespoke lease provision" pertaining to the calculation of the lessor's royalty. The unusual language provided, in an addendum to the lease, that in determining the royalties to be paid to lessors, if "*any reduction or charge* for [postproduction] expenses or costs" has been "include[d]" in "any disposition, contract or sale" of production, those amounts "shall be *added to the . . . gross proceeds* so that [the landowners'] royalty *shall never be chargeable directly or indirectly with any costs or expenses* other than its pro rata share of severance or production taxes."[106] The addendum also included language, which has become relatively common, disclaiming any applicability of the Texas Supreme Court's

[104] *Id.* at 366.
[105] *Id.* at 367.
[106] *Sheppard*, 668 S.W.3d at 336 (emphasis in opinion).

decisions in *Heritage Resources, Inc. v. NationsBank*[107] and *Judice v. Mewbourne Oil Co.*[108] and specifically stating that the language of the addendum is not surplusage.

The interpretation advanced by the lessee was that the addendum constituted an "add-back clause," which required that the lessee calculate royalty on the basis not only of the proceeds received under a contract, but also any production costs deducted from those proceeds by reason of a netback pricing formula. The lessee admitted that this explanation renders the addendum language mere surplusage, since it merely emphasizes the cost-free nature of a gross proceeds royalty clause. It also asserted that the reference to *Heritage Resources* and *Judice* were intended to confirm that the lessor's royalty was not to bear any of the lessee's postproduction costs, not post-sale expenses incurred by the buyer of gas, since those cases involved lease provisions concerned with the deduction of the lessee's expenses.

The court affirmed the lower courts, holding that this language required the lessee to pay royalty on the basis of the gross proceeds received under a netback pricing contract *plus* amounts deducted in calculating the contract price reflecting the buyer's post-sale, post-production costs. Rejecting the lessee's interpretation, the court found that the addendum "plainly and in a formal way" expressed the intent for the agreement to operate differently from background oil and gas law principles in two ways: "first by requiring that royalties be paid on gross proceeds and then by requiring an *addition* to gross proceeds for the stated purpose of freeing the landowners' royalty from 'any costs or expenses other than its pro rata share of severance or production taxes.'"[109] In other words, the royalty does not bear costs to increase the value of a product that has already been produced, which ordinarily is deductible under Texas law.

The significance of *Sheppard* may be in how it confirms a statement made in *Heritage Resources* that until *Sheppard* seemed dubious: "To make a royalty free of postproduction costs, a lease could change the point at which it was valued or specify that something would be added to the royalty base."[110] While in *Heritage Resources*, language added to a royalty clause failed to accomplish this goal, the addendum in *Sheppard* succeeded, proving the point and providing an example to future drafters.

III. The Texas Supreme Court interprets a force majeure clause in an oil and gas lease, in Point Energy Partners Permian, LLC v. MRC Permian Co., 669 S.W.3d 796 (Tex. 2023).

In this dispute over the defendant's oil and gas lease, the defendant asserted that an event of force majeure excused its delay in commencing drilling operations to continue the lease. The lease contained a force majeure clause that provided in substance that "[w]hen Lessee's operations are delayed by an event of force majeure, being a non-economic event beyond Lessee's control," and timely notice is given, the lease shall "remain in force" during the delay and the lessee shall have 90 days to "resume operations."[111]

[107] 939 S.W.2d 118 (Tex. 1996).
[108] 939 S.W.2d 133 (Tex. 1996).
[109] *Seppard*, 668 S.W.3d at 346.
[110] *Id.* at 347 (citing *Heritage Resources, Inc.*, 939 S.W.2d at 131 (Owen, J.)).
[111] *Point Energy Partners*, 669 S.W.3d at 799.

Under the express terms of a continuous-drilling provision of the parties' oil and gas lease, lessee had until May 21, 2017, to spud a new well to avoid partial termination of the lease under a retained acreage clause. The lessee, by mistake, scheduled the rig to spud on June 2. It learned of its mistake two weeks *after* the May 21 deadline. One week after discovering the error, the lessee notified lessors that the rig it scheduled to spud the new well was delayed by a well stability issue encountered around April 21 on another, unrelated lease, and that this excused its delinquency in commencing operations before May 1 under the force majeure clause. The alleged delay occurred on an unrelated lease over 60 miles away from the subject lease and delayed the rig by only 30 hours.

In an opinion that reads like an entry in a treatise on oil and gas lease force majeure clauses, the Texas Supreme Court held that the clause did not excuse the lessee's failure to timely commence drilling. "By requiring 'Lessee's operations' to be delayed 'by' a force majeure event, the clause imposes a causal-nexus requirement that is a necessary predicate to properly invoke the clause."[112] The lessee argued that the well stability issue on its other lease did indeed cause a delay of its scheduled drilling operations on the subject lease, and that the force majeure clause does not require anything more. Disagreeing, the court held that the clause was intended to excuse only such delays as would (otherwise) cause the lease to terminate. Since the lessee had scheduled the required operations to commence *after* the deadline, the delay caused by the off-lease event was not the *cause* of the missed deadline. Thus, the force majeure clause's causal-nexus requirement was not satisfied by the off-lease well stability event. Accordingly, the court held the lease terminated.

IV. A panel of the Texas Court of Appeals holds that a purchaser under an allegedly defective sale and assignment adversely possessed a nonpossessory working interest from the seller, in PBEX II, LLC v. Dorchester Minerals, L.P., 670 S.W.3d 374 (Tex. App. 2023) (petition for review filed Aug. 11, 2023).

This case presented a straightforward adverse possession scenario in every way except for one: the subject property was a nonoperating working interest in a jointly operated production unit. Torch succeeded to the ownership of an oil and gas lease (the Willis Lease) covering 25% of the total working interest in the mineral estate underlying Section 4. In 1990, Torch sold to Dorchester the Willis Lease, which was then subject to a JOA covering the other working interests in the section and which was held by production from two wells. From 1990 to 2016, Dorchester "performed all the functions of the Working Interest owner: paying their share of the costs of production; receiving revenues from the sale of the Working Interest's share of gas; paying royalties to the lessors under the Willis Lease; and making elections required under the JOA."[113] Torch subsequently conveyed its interest in the Willis Lease to PBX II.

This suit followed, in which the parties disputed title to the Willis Lease. The opinion does not explain why, but it is clear the parties disagree whether the sale of the Willis Lease from Torch to Dorchester was effective. The issues on appeal centered on Dorchester's claim that its

[112] *Id.* at 807.
[113] *Dorchester Minerals*, 670 S.W.3d at 379.

uninterrupted 26 years[114] of acting in every way as though it owned the entire nonoperating working interest in Section 4 ripened into limitation title to the entire interest.

Torch and PBX II contested Dorchester's claim, arguing that a nonoperating working interest in minerals is nonpossessory in nature and thus not subject to adverse possession. In this sense, they argued, a nonoperating interest is like a nonparticipating royalty interest, which a Texas Court of Appeals held not subject to adverse possession in the 2019 decision, *Moore v. Moore*.[115] The court rejected this assertion. Texas law views the working interest in minerals to be a possessory estate, and, the court explained, "[c]ontrary to the urging of PBEX and Torch, there is no distinction between 'operating' and 'non-operating' working interests under Texas Law—all working interests are possessory."[116]

Torch and PBX next argued that Dorchester failed to satisfy the requirement of "open and visible" possession of the interest for purposes of adverse possession. Basically, this argument amounted to the fact that a nonoperating working interest cannot openly adversely possess the true owner of the interest because, by definition, it conducts no surface operations that might put the true owner on notice of the adverse claim. This fact, the court demurred, is irrelevant because adverse possession of a working interest in minerals requires acts that are hostile to the rights associated with such an interest: the rights to produce, remove, and deplete the minerals in place. "Setting foot" on the surface is not essential. Since Dorchester's actions (noted *supra*) were consistent with how the true owner would possess a nonoperating working interest given the character of such property, the court found that it satisfied the requirements of adverse possession.

Further, the court held (it appears in the alternative) that the operator under the JOA adversely possessed the interest on behalf of Dorchester. In so reasoning, the court analogized Dorchester, as nonoperating working interest owner under a JOA, as the operator's landlord. It is well recognized under Texas law that a tenant may adversely possess on behalf of its landlord even in the absence of an agency relationship between the two. By disbursing revenues to and obtaining elections from Dorchester, and "'by attorning to' Dorchester and its predecessors, the operator, like a surface tenant on behalf of a landlord claimant, adversely possessed the Working Interest on behalf of Dorchester and its predecessors for over twenty-five years."[117]

The court further found that the fact that Dorchester (or its predecessors in interest) did not interrupt the prescriptive period by going "nonconsent" to subsequent operations under the JOA. This is because Dorchester did not forfeit its rights to any production from Section 4 in order to go nonconsent, and therefore did not surrender its possession of the working interest.

A dissent by Judge Doss argued that Dorchester did not establish adverse possession because Texas law requires actual drilling to adversely possess an interest in minerals. Further, under the terms of the JOA, going nonconsent relinquishes the owner's interest in the well and share of production therefrom. Accordingly, Judge Doss would have reversed the trial court's grant of summary judgment of adverse possession in favor of Dorchester.

[114] One more than the applicable limitations period of 25 years.
[115] 568 S.W.3d 725, 733 (Tex. App. 2019).
[116] *Dorchester Minerals*, 670 S.W.3d at 381.
[117] *Id.* at 385.

V. A panel of the Texas Court of Appeals passes on the validity of the Railroad Commission's grant of a production sharing agreement (PSA) well permit, in Railroad Commission v. Opiela, No. 03-21-00258-CV, 2023 Tex. App. LEXIS 4726, 2023 WL 4284984 (Tex. App. June 30, 2023).

This case examines the ways in which a mineral lessee may develop reserves underling multiple tracts of land by horizontal drilling in Texas. The traditional method is by pooling the tracts or the leases encumbering the tracts for the drilling of a well "where production from any of the tracts in the pooled unit is treated as production from all of the tracts."[118] Texas law also recognizes two other vehicles for linking adjacent properties for the production of minerals: production sharing agreements (PSAs) and allocation wells. Under a PSA, "the interest owners on the various tracts agree to how production from a multitract well will be shared irrespective of where take points are."[119] An allocation well, in contrast, is "a horizontal well that traverses the boundary between two or more leases that have not been pooled and for which no agreement exists among the royalty owners as to how production will be shared."[120] Unlike pooling and a PSA, allocation wells do not require any consent or agreement among the affected mineral owners.

This case concerns the Railroad Commission's regulatory authority to grant permits for multitract PSA wells. In 2008, a divided Commission approved the promulgation of an application for a permit to drill multitract wells on the basis of a PSA, which included the condition that the operator certifies that at least 65% of the working and royalty interest owners in each component tract have signed the PSA.[121] The Commission has not otherwise adopted rules specific to PSAs.

In this dispute, lessors protested the operator's application with the Railroad Commission for a permit to drill a PSA well under multiple tracts including the premises of their lease. The complainants showed that their oil and gas lease with the operator contained an anti-pooling clause expressly prohibiting their tract to be pooled with others for purposes of drilling a well that would hold all the leases subject to the pooled unit. The Commission's granting the operator's application for a PSA well, they contended, violates the anti-pooling provision of their lease by effectively subjecting their tract to "pooling by another name." The complainants further argued that granting the permit violated the Commission's authority because the anti-pooling clause in their lease precluded the Commission from making the necessary finding that the operator had a good-faith claim to the right to drill a horizontal well into their tract. Such a finding is required by the Commission's own Form P-16 for horizontal well permits.[122]

The court disagreed with the mineral owners and affirmed the Railroad Commission's position that PSAs are not the equivalent of pooling. The Commission cited previous adjudications in which the Commission concluded that an operator need not demonstrate that it has pooling authority as a condition to granting it a permit to drill a horizontal well. Thus, according to the

[118] *Opiela*, at *4.
[119] *Id.* (citing E. Smith & J. Weaver, Tex. Law of Oil & Gas § 9.9(B), at 9-167-70 (2d Ed. 2020)).
[120] *Id.* (quoting Clifton A. Squib, *The Age of Allocation: The End of Pooling As We Know It?*, 45 TEX. TECH. L. REV. 929, 930 (2013)).
[121] *Id.* at *17–18.
[122] *Id.* at *19–20.

court, the grant of a permit for a PSA well is not tantamount to pooling the lands where the horizontal well will be drilled.

The court next considered whether the Commission erred when it concluded that, despite the complainants' arguments, it has no authority to review the operator's leases to determine whether it has authority to drill the well. The Commission did find that the applicant had a good-faith claim of right to operate, but it did not expressly consider the anti-pooling clause in the operator's lease with the complainants. This is all that is required, said the court, since "[w]hen [the Commission] grants a permit to drill a well it does not undertake to adjudicate questions of title or rights of possession. These questions must be settled in the courts."[123] Instead, the agency's grant of a permit merely removes the regulatory bar to drilling that is imposed to prevent waste and protect correlative rights.

Finally, the court determined that the Commission erred when it found that the operator had shown that it has the consent of 65% of the mineral and working interests to the production sharing agreement. Assuming this was a properly adopted rule in the first place, the court held that the 65% threshold cannot be met by consents to pooling, "absent a good-faith showing that the consents to pool and the PSA call for the same sharing of production for the horizontal well across tracts that are not pooled."[124] Since this evidence was lacking, the operator failed to satisfy the 65% rule. The court remanded the matter to the Commission where, it indicated, the parties might pursue an application for an allocation well, instead.

Judge Kelly, in dissent, argued that consents to pooling and ratifications of pooled units do in fact dictate how production will be shared with the royalty owners of the pooled tracts and thus should suffice to satisfy the 65% requirement.

VI. A panel of the Texas Court of Appeals holds that the oil and gas lessee owns the produced water from its wells, in Cactus Water Services, LLC v. COG Operating, LLC, No. 08-22-00037-CV, 2023 Tex. App. LEXIS 5600 (Tex. App. July 28, 2023).

The first line of the opinion explains that "[t]his case decides who owns produced water arising from a hydraulic fracturing operation: [COG, the existing mineral lessee] or [Cactus, the holder of a subsequent produced-water lease agreement with the surface owners]."[125] Throughout the body of the opinion, however, it appears that the court's reasoning is meant to apply to all produced water, not just flowback and produced water from hydraulic fracturing operations.

Cactus argued that COG's oil and gas leases conveyed rights to the oil and gas and other hydrocarbons, but not water, noting that the leases' only mention of water limit the lessee's rights to use water on the premises. COG countered that the "general intent" of its oil and gas leases was to convey rights in oil and gas in their natural form, which entails produced water as a waste product, which together with the hydrocarbons form a "single, combined product stream."

[123] *Id.* at *24 (quoting Magnolia Petroleum Co. v. R.R. Comm'n, 170 S.W.2d 189, 191 (Tex. 1943)).
[124] *Id.* at *32.
[125] *Cactus Water Servs.*, at *1.

The court framed the question as follows: "The parties' disagreement as to whether produced water is part of the mineral estate essentially depends on whether "produced water" is, as a matter of law, water or if it is waste."[126] According to this framing, if produced water is "water" within the meaning of COG's oil and gas leases, then COG is limited in its use of it and ownership would not rest with COG. If, instead, produced water is construed to be a waste, then ownership passed to COG under its oil and gas leases.

Acknowledging that the definition of produced water appears nowhere in the leases, the court looked to the relevant regulatory treatment of produced water to furnish the context in which the parties would have drafted the leases. Surveying a variety of definitions of oilfield waste and water under Railroad Commission statutes and regulations and environmental codes, the court concluded that produced water more closely conforms to the waste definitions. It thus held that produced water is a waste byproduct of oil and gas and therefore is conveyed to the lessee under an oil and gas lease.

Writing a lengthy dissent, Judge Palafox would have held that Cactus's produced water leases were effective in conveying superior rights in the produced water. Judge Palafox began by interpreting the language of the oil and gas leases' granting clauses to ascertain whether they conveyed produced water along with the "oil and gas" or "oil, gas, and other hydrocarbons." She concluded that they did not, on the authority of *Moser v. U.S. Steel Corp.*, which both adopted the ordinary meaning test for interpreting which unnamed substances a conveyance of "oil, gas, and other minerals" may include and "confirmed that water remains as part of the surface estate and is not conveyed by the terms, "oil, gas and other minerals."[127] An even earlier case, *Robinson v. Robbins Petroleum Corp.*, also explained that "water itself is an incident of surface ownership in the absence of specific conveyancing language to the contrary," even when it contains other elements, like dissolved salt, as does produced water.[128] Thus, produced water remained part of the surface estate after the oil and gas leases were conveyed.

Although produced water was not included in the grant of oil and gas under COG's leases, Judge Palafox reasoned that COG enjoyed the right to use the produced water pursuant to its easement in the surface estate. "As an owner of the mineral estate, COG has the right to use the produced water as is reasonably necessary for its production of oil and gas, but it has no ownership rights to that estate."[129] Title to the produced water, however, rested with Cactus.

It should be noted that Texas groundwater law follows an ownership-in-place theory and the rule of capture and in that sense is highly distinct from Oklahoma groundwater law.

[126] *Id.* at *12.
[127] 676 S.W.2d 99, 101 (Tex. 1984).
[128] 501 S.W.2d 865, 866 (Tex. 1973).
[129] *Cactus Water Servs.*, 2023 Tex. App. LEXIS 5600, at *29 (Palafox, J., dissenting).

VII. A Panel of the Texas Court of Appeals applies a 2019 limitation to the *Duhig* rule, in Echols Minerals, LLC v. Green, 2023 Tex. App. LEXIS 6318, 2023 WL 5280828 (Tex. App. Aug. 17, 2023).

This was a title dispute over a fractional NPRI reserved in a 1952 deed. The trial court granted summary judgment to appellees, who claimed as successors to the grantee under the 1952 deed, on the basis of *Duhig v. Peavy-Moore Lumber Company*.[130] The Texas Court of Appeals reversed, holding that as limited by the 2019 Texas Supreme Court decision in *Trial v. Dragon*,[131] *Duhig* did not apply to the 1952 deed because the grantors did not own the exact interest necessary to remedy the overconveyance. The court explained the test for applying the *Duhig* rule following *Dragon* thusly:

> In summary, there is a two-part test to determine if *Duhig* is applicable to a conveyance. First, we must determine if there is "a *Duhig* problem" with the conveyance—did the grantor convey an interest greater than what he or she possessed, such that there is an over-conveyance and therefore, a failure of title, while at the same time reserving an interest? If there is a *Duhig* problem, then we must determine if *Duhig* provides the grantee and its successors a remedy—did the grantor own the *very interest* required to remedy the breach of warranty at the time of the conveyance so as to nullify or reduce the grantor's reservation?[132]

VIII. Applying Texas law, the New Mexico Court of Appeals holds that a pricing formula in a mineral interest purchase agreement provided a sufficiently definite basis for determining the price of the subject interests as to be enforceable, in Foundation Minerals, LLC v. Montgomery, 2023 WL 6527782, 2023 N.M. App. LEXIS 78, __ P.3d __ (N.M. Ct. App. Oct. 2, 2023).

The buyer under a certain Mineral Estate Purchase Agreement (MEPA) brought this action against the seller for breach of contract for failing to close the transaction. The buyer sought specific performance of the seller's obligations. Following the trial court's rulings on summary judgment, the parties both appealed various issues. The issue on appeal that is of interest here is whether the MEPA was enforceable or, as seller argued, did not constitute a contract because the parties never mutually assented to the price term.

The contract provided for the sale of all of seller's interests in leased and unleased mineral estates as well as nonparticipating royalty interests in twenty-five separate tracts of land in Lea County, New Mexico. Paragraph 2 entitled "Purchase Price" stated as follows:

> Buyer agrees to pay Seller for the oil and gas Mineral Estate $15,535.19 per Net Royalty Acre (Net Royalty Acre being defined as: The equivalent of 1 Net Mineral Acre being leased at a 1/8th Royalty. For Example: 1 NMA leased at a 1/4th is equal to 2 NRA) owned by Seller in the lands covered by this Agreement (the "Purchase Price"). The final amount of the net royalty acres and thus the total purchase price

[130] 144 S.W.2d 878 (Tex. 1940).
[131] 593 S.W.3d 313 (Tex. 2019).
[132] *Echols Minerals*, at *18 (emphasis added).

> shall be determined by title examination, and for the purposes of this Agreement, it is believed that the Seller owns 257.48 Net Royalty Acres for a total Purchase Price of $4,000,000.00.[133]

Exhibit A included the legal descriptions of the twenty-five tracts of land and each tract's gross acreage and corresponding Net Mineral Acres and Net Royalty Acres.

Seller contended that there was no meeting of the minds as to the price, because the formula for the purchase price was expressed in Net Royalty Acres. Because Net Royalty Acres are "defined by the royalty for a leased mineral interest," "the formula could not apply to calculate a price for either unleased mineral interests (which clearly have no leases) or nonparticipating royalty interests (which represent only the right to receive a payment under a lease and not to participate in the lease itself)." Since no purchase price was defined for these interests, it was argued, the MEPA lacked the mutual assent necessary to forming a contract.[134]

Price is an essential term for the sale of mineral interests under Texas law.[135] Thus, the purchase price must be expressed with a reasonable degree of certainty and definiteness. Here, the court found that the price formula set up a means of determining with reasonable certainty and definiteness the purchase price for the seller's leased mineral interests. "According to Section 2 of the MEPA, for every Net Mineral Acre that is leased at 1/4 royalty—or 25%—Buyer would purchase 2 Net Royalty Acres at a price of $15,535.19 per Net Royalty Acre. Thus, a Net Royalty Acre is calculated according to Net Mineral Acres and the percent royalty interest for the leases of those Net Mineral Acres."[136]

The court further held that the pricing formula could be interpreted so as to make the pricing for unleased mineral interests and nonparticipating mineral interests sufficiently definite. "On summary judgment", the court wrote, "Buyer presented undisputed evidence that for unleased mineral interests, a 25 percent royalty rate is 'common in the purchase and sale of mineral interests.' The MEPA additionally sets forth that nonparticipating royalty interests would be purchased assuming a 25 percent royalty on all leases after title examination confirmed the rate of the royalty interest [under the applicable leases]."[137] The court thus interpreted the pricing formula to impose a 25% royalty interest on all unleased Net Mineral Acres based on evidence of trade usage.

The court further assumed that the Net Royalty Acres for a nonparticipating royalty interest could be determined based on the royalty rate under an oil and gas lease of the underlying mineral interest. It explained, "Though the nonparticipating royalty interests themselves convey no right to participate in a lease, the right to receive payment under leases would still be determined by the royalty rate in the lease."[138] This may be true of a nonparticipating royalty interest, but not always. Some NPRIs indeed entitle their holder to a portion of the royalty payable under an oil and gas

[133] *Montgomery*, at *12.
[134] *Id.* at *17.
[135] *Id.* (citing cases).
[136] *Id.* at *16.
[137] *Id.* at *22.
[138] *Id.*

lease then in effect. It is possible, and even common, however, to create an NPRI in a fixed share of production from a mineral estate, regardless of whether the mineral estate is leased or what royalty rate is reserved under the lease. The existence of the latter kind of NPRI should not undermine the definiteness of the pricing term in this MEPA, however, because the Net Royalty Acres for such an interest could be calculated based on the fraction of the NPRI expressed in its organic instrument.

Accordingly, the court held that the parties agreed as a matter of law about how to calculate the price term. It denied summary judgment on the buyer's request for specific performance, however, based on remaining issues of fact.

PART FIVE:
OTHER JURISDICTIONS APPELLATE DECISIONS

I. 10th Circuit adopts Texas law as standard for determining when the accommodation doctrine applies under Colorado law, in Bay v. Anadarko E&P Onshore, LLC, 73 F.4th 1207 (10th Cir. 2023).

Severed surface owners, the Bays, sued the severed mineral owner, Anadarko, for trespass, alleging that Anadarko's oil and gas lessees had exceeded the mineral estate's surface-use rights by drilling multiple vertical wells when fewer directional wells would have been possible. Following the Bays' presentation of evidence in their case-in-chief at trial, the district court entered judgment as a matter of law against the Bays, finding that they had presented insufficient evidence to establish trespass. The Bays appealed to the 10th Circuit, which reversed in a case styled *Bay I*, holding that the district court applied an incorrect legal standard for trespass.[139] In noting the correct standard, the 10th Circuit held

> that Colorado's common law of trespass required the Bays to show that Anadarko's lessees had "materially interfered" with the Bays' farming operations. In outlining Colorado's test for material interference, we relied on Texas cases that required plaintiffs to show a mineral trespasser's conduct either completely precluded or substantially impaired their farming operations and that there was no reasonable alternative to their current farming operations.[140]

On remand, the district court again entered judgment for Anadarko and again the Bays appealed. In this appeal, the question was whether the district court erred in applying the 10th Circuit's articulation of the material interference standard from its opinion in *Bay I*, because it was mere dictum and conflicts with Colorado's accommodation doctrine as articulated in *Gerrity Oil & Gas Corp. v. Magness*.[141]

In *Bay I*, the 10th Circuit interpreted *Gerrity* as setting up a tripartite burden-shifting framework for determinations of whether a mineral owner must accommodate the conflicting surface uses of a surface owner. It articulated the framework as follows: First, the surface owner

[139] 912 F.3d 1249 (10th Cir. 2018).
[140] *Bay II*, 74 F.4th at 1209–10.
[141] 946 P.2d 913 (Colo. 1997).

bears the burden of making a prima facie showing that the mineral owner's conduct "materially interfered with surface uses." If this showing is made, the burden of production then shifts to the mineral owner to show that its surface conduct was reasonable and necessary. If the mineral owner satisfies this burden, the burden of production shifts back to the surface owner to show that reasonable alternatives were available to the mineral owner at the time of the alleged trespass. The ultimate decision whether the surface use was reasonable and necessary rests with the trier of fact.[142]

At issue in this case was whether the Bays satisfied their initial burden of showing material interference. The court in *Bay I* looked to Texas law to inform what constitutes a material interference under the *Gerrity* test. It did so because *Gerrity* was silent on the issue but for other propositions cited favorably to the Texas Supreme Court case establishing the accommodation doctrine, *Getty Oil v. Jones*. Thus, the court reasoned that "*Getty* along with the Texas Supreme Court's more recent case in *Merriman v. XTO Energy, Inc.*, 407 S.W.3d 244, 249 (Tex. 2013), 'provide[d] helpful guidance on the meaning of material interference,' and 'suggest[ed] that surface use must be infeasible or nearly impossible under the circumstances.'"[143] Under *Merriman*, the court held that to establish a prima facie showing of material interference, the surface owner must demonstrate that its uses were *completely precluded or substantially impaired* and that *no reasonable alternative method* was available to the surface owner.

In *Bay II*, the court concluded that its statements in *Bay I* regarding the substance of the material interference requirement were holding, rather than dictum, because they were necessary to the resolution of the issues before the court in *Bay I*, even though that case did not resolve whether the Bays had satisfied the standard. Because the court's articulation of the standard was holding, even though it did not decide whether the standard was met, the standard itself became the law of the case and was binding on the district court on remand. Thus, the Bays were held to that standard. The court in *Bay II* then held as a matter of law that the evidence presented by the Bays that they were merely inconvenienced by the oil and gas lessees' drilling seven wells instead of one or two was insufficient to satisfy their burden.

Notably, although the Bays failed to satisfy their burden to establish accommodation, the court in *Bay I* had opined that they presented evidence sufficient to show that there were reasonable alternatives available to the lessee's vertical drilling: horizontal drilling. Thus, *Bay I* may be persuasive authority on the point that drilling horizontal wells could be a reasonable alternative where vertical wells materially interfere with the use of the surface.

II. 8th Circuit Court of Appeals applies North Dakota's *Duhig* doctrine, which appears to be alive and well, in Northern Oil & Gas, Inc. v. EOG Resources, Inc., 74 F.4th 899 (8th Cir. 2023).

The case involved an alleged overconveyance by Anderson, who in 1949 conveyed to Youngblood a 1/2 mineral interest in several tracts of land. Then, in 1962, Anderson conveyed a 3/4 mineral interest in the same lands to Johnson, reserving 1/4 interest in the minerals to himself. The successors to Johnson's interest sued to quiet title against the successors to Anderson seeking

[142] *Bay I*, 912 F.3d at 1257.
[143] *Id.* at 1261.

title to a 1/2 mineral interest in the disputed lands, rather than merely 1/4, as Anderson's successors argued.

The instant litigation, brought in the federal courts for the District of North Dakota, mirrored claims brought ten years earlier in the state courts of North Dakota. In the state court litigation, a successor to Anderson was held by the North Dakota Supreme Court, in a case styled *Johnson v. Finkle*, not to own any interest in the minerals under North Dakota's *Duhig* doctrine.[144] In this federal court litigation, the holder of an oil and gas lease granted by the successor to Anderson who litigated the state court action made the same claim that failed in *Johnson v. Finkle*, namely that the 1962 reserved to Anderson an undivided 1/4 mineral interest.

The court in the instant case applied the North Dakota Supreme Court's analysis from *Johnson v. Finkle* to hold that Anderson failed to reserve any interest in the 1962 deed. I report this unexceptional result because of the court's reiteration of North Dakota's *Duhig* doctrine, which the reader will find notably different from the version of *Duhig* that recent Texas decisions have embraced:

> When there has been an overconveyance of mineral interests, the Supreme Court of North Dakota applies the rule of construction from *Duhig v. Peavy-Moore Lumber Co.*, 135 Tex. 503, 144 S.W.2d 878 (Tex. 1940)—where mineral interests conveyed and reserved by a property owner total more than a 100% interest, "this grant and the reservation cannot be given effect, so the grantor loses because the risk of title loss is on him." Gawryluk v. Poynter, 2002 ND 205, 654 N.W.2d 400, 405 (N.D. 2002) (quotation omitted). "The effect of *Duhig* is that . . . if a grantor does not own a large enough mineral interest to satisfy both the grant and the reservation, the grant must be satisfied first because the obligation incurred by the grant is superior to the reservation." *Id.*

III. North Dakota Supreme Court distinguishes *Tres C* in a total cessation of production case, in Zavanna, LLC v. GADECO, LLC, 994 N.W.2d 133 (N.D. 2023).

Plaintiff top lessee sued owners of bottom leases covering the Golden Unit and arguably held by production from the Golden Well operated by one of the defendants. The trial court quieted title in plaintiffs after finding at a bench trial that production from the Golden Well ceased over three periods and that defendants failed to timely commence drilling or reworking operations under the bottom leases' 90-day cessation-of-production clause.

On appeal, the defendants argued the trial court improperly imposed the burden of proving that production did not cease and that the lessees complied with the cessation-of-production clause on the defendants. The court reminded us that it is generally the party requesting cancellation or termination of an oil and gas lease to prove the lease is no longer valid, and that "in an action to quiet title to real property the plaintiff must rely on the strength of its own title."[145] Thus, the plaintiff should have born the burden to show that production in paying quantities permanently

[144] 836 N.W.2d 444, 49 (N.D. 2013).
[145] *Zavanna*, 994 N.W.2d at 138 (quoting Robertson v. Brown, 25 N.W.2d 781, 785 (N.D. 1947); WFND, LLC v. Fargo Marc, LLC, 730 N.W.2d 841 (N.D. 2007)).

ceased and (the court assumed without deciding) that the lessee failed to commence operations in compliance with the relevant lease savings clauses.

The court went on to review the trial court's findings that the leases terminated as a result of three separate periods of cessation. In period one, the submersible ESP pump in the Golden Well ceased operating in July 2014. The trial court found that the defendant that operated the well diagnosed the problem in August 2014 and worked with a service provider to design a new pump. Yet, the defendant waited months to order the new pump and it was not installed until December 2014. Installation required the use of a workover rig, which did not arrive to the well site until December 4, some 143 days after the pump first ceased to operate. The court affirmed the trial court's finding that the defendant's diagnostic work and ordering the new pump were not reworking operations, but merely "minimal preparatory steps," and thus no reworking operations were commenced within 90 days of the cessation as required by the cessation-of-production clause.[146] The court further found that even if these preparatory steps could be considered "commencement," the defendant did not pursue the operations with reasonable diligence.

Regarding the second period of cessation, the defendants asserted that the well in fact produced small amounts of oil (3.3 barrels) and gas (11 mcf) during the period of alleged nonproduction. Citing *Tres C, LLC v. Raker Resources, LLC*, the defendants argued that the plaintiff failed to show that this production was not in paying quantities and that the trial court erred when it found that this small amount of production was not in paying quantities without assessing it over "a reasonable period."[147] The North Dakota Supreme Court distinguished *Tres C* on the grounds that it addressed a cessation of profitable production (what I called earlier a "constructive cessation"), whereas this case raises a *total* cessation of production. "The Golden Well produced 3 barrels of oil and11 Mcf of gas over a period of almost four months. While a 'look-back period' may be necessary in cases where it is unclear whether (profitable) production ceased, production is not genuinely at issue from November 5, 2015, until the end of February 2016." The court went further: "To the extent that *Tres C* would require a 'look-back period' in every case, even where production ceased completely and profitability is not at issue, such is not required in North Dakota."[148] Based on this four-month period of virtually no production, the court held that the cessation-of-production clause was triggered and not satisfied by timely commencement of operations, terminating the lease.

[146] *Id.* at 142.
[147] *Id.* at 143–44 (citing Tres C, LLC v. Raker Resources, LLC, 2023 OK 13).
[148] *Id.* at 144.

ARTIFICAL INTELLIGENCE AND PROFESSIONAL RESPONSIBILITY

Melissa Mortazavi
and
Sarah Cravens

Artificial Intelligence and Professional Responsibility

PROF. SARAH CRAVENS, W&L LAW

ASSOC. DEAN MELISSA MORTAZAVI, OU LAW

Agenda

I. Introduction

II. AI and Lawyers' Responsibilities

III. AI in the Courts

IV. Conclusions and Questions

AI and Lawyers' Responsibilities

What Do We Mean by "AI"?

- Been around since the 1950's
- So, What's different?
  - Ability to engage in *generative* behaviors
  - Large language learning (Google's Bard, Chat GPT)
- Misconceptions:
  - Accurate
  - Free-standing
  - Confidential
  - Content is authorized

Where have lawyers gone wrong with AI so far?

1. Mata v. Avianca, Inc. (1:22-cv-01461) District Court, S.D. New York
   - June 22, 2023 the Court issued sanctions against the attorneys noting that. “existing rules impose a gatekeeping role on attorneys to ensure the accuracy of their findings.” Monetary sanction and duty to distribute opinion and transcript to all the parties involved or mentioned (including judges).
2. Zachariah Crabhhill, Colorado Springs (June 2023)
3. Dennis Block, California (October 2023)

These cases arose largely because of human ignorance of what AI does and the failure to fact check and exert oversight.

Key ABA Model Rules Implicated

- *Competence (1.1)*
- *Confidentiality (1.6)*
- *Candor (3.3)*

ABA Model Rule 1.1

Competence

Comment 8: "To maintain the requisite knowledge and skill, a lawyer should keep abreast of changes in the law and its practice, including the benefits and risks associated with relevant technology, engage in continuing study and education and comply with all continuing legal education requirements to which the lawyer is subject.”

ABA Model Rule 1.6

Confidentiality

(c) A lawyer shall make reasonable efforts to prevent the inadvertent or unauthorized disclosure of, or unauthorized access to, information relating to the representation of a client.

Comment 4:

Paragraph (a) prohibits a lawyer from revealing information relating to the representation of a client. This prohibition also applies to disclosures by a lawyer that do not in themselves reveal protected information but could reasonably lead to the discovery of such information by a third person."

ABA Model Rule 3.3

Candor

(a) A lawyer shall not knowingly:

(1) make a false statement of fact or law to a tribunal or fail to correct a false statement of material fact or law previously made to the tribunal by the lawyer

Is it Best for Lawyers to Just Avoid Using AI completely?

Most Likely Not:

Competence:

“ Competent handling of a particular matter includes inquiry into and analysis of the factual and legal elements of the problem, and ***use of methods and procedures meeting the standards of competent practitioners***. It also includes adequate preparation. “ABA Model Rule 1.1, Comment 5

Scope:

A lawyer may limit the scope of the representation if the limitation is reasonable under the circumstances and the client gives informed consent.” ABA Model Rule 1.2 (c)

Fees: " A lawyer shall not make an agreement for, charge, or collect an unreasonable fee or an unreasonable amount for expenses." ABA Model Rule 1.5

Resources for AI Supervision

Prompting AI - Free Prompting Course

https://www.promptingguide.ai/

Write.Law "ChatGPT and Legal Writing"
https://write.law/blog/chatgpt-and-legal-writing-the-perfect-union

AI in the Courts

Standing Orders on Artificial Intelligence

- Advent of orders:
  - Shifting landscape / consistent ethical obligations
  - Rule 11, various MRPCs for attorneys
  - Integrity / competence / upholding rule of law, etc for judges.
- Spectrum of language
  - AI v Generative AI
  - Specifications about use
- Variety of requirements imposed
  - Acknowledgment of order / existing rules
  - Certification of accuracy / human responsibility
  - Disclosure of use (at all)
  - Disclosure of specifics of use (including particular tools, means, etc.)
- Practical takeaways

Some Relevant Rules and Ethical Concerns for Use of AI in the Courts

- Promoting Public Confidence in the Judiciary
- Avoiding External Influence
- Bias
- Competence
- Appropriate Oversight

Examples of Current Use of AI by Courts in the U.S. (and some comparisons abroad)

Research: search suggestions/refinements

Dashboards: pulling key data to templates

Dispute Resolution: from meeting platforms to suggested resolutions

Chatbots: from directions to suggestions to resolutions

Other “Assistive” Function Examples

Use of Generative AI in Opinions/Hearings Abroad…

In Colombia:

- Consultation of ChatGPT re legal question for resolution by the court.
- Judge compared to services provided by judicial staff.
- 2022 law promoted use of technology by public lawyers to improve efficiency.

In India:

- Consultation of ChatGPT by appellate judge in civil matter on basic question of legal doctrine to help craft an order.
- "Testing the potential of [ChatGPT] assistance in improving quality of judicial decision making."
- "This is now; this is the future. The beneficiary is the litigant and the society."

In Malaysia:

- Nationwide pilot to test efficiency of AI in sentencing used specially developed software.
- Use of AI recommendations drew defense objections on several grounds.
- Chief acknowledged expected objections, but noted test was necessary to determine constitutionality.

In Bolivia:

- During online hearing, court consulted ChatGPT "to clarify certain concepts."
- Defense lawyer called this use of AI "arbitrary" and a "disaster."

Split Opinions…

From a July 2023 National Judicial College survey:

Of 332 responding judges:

76% had not tried ChatGPT or other forms of (generative) AI at all.

17% had tried it and liked it.

7% had tried it and not liked it.

Conclusions & Questions

THE ENERGY LEASE: REVIEWING ITS USE IN THE OIL AND GAS, MINING, AND RENEWABLES INDUSTRIES

Andy Graham

STEPTOE & JOHNSON PLLC

The Energy Lease

Reviewing Its Use in the Oil and Gas, Mining and Renewable Industries

Eugene Kuntz Conference on Natural Resources Law & Policy
Oklahoma City, Okla.

November 10, 2023

Andy Graham

andy.graham@steptoe-johnson.com

(304) 598-8161

Our Energy Practice

- Nationally recognized energy team
- Strategic locations covering all of the major U.S. shale plays, including Permian, Eagle Ford, Niobrara, Marcellus and Utica
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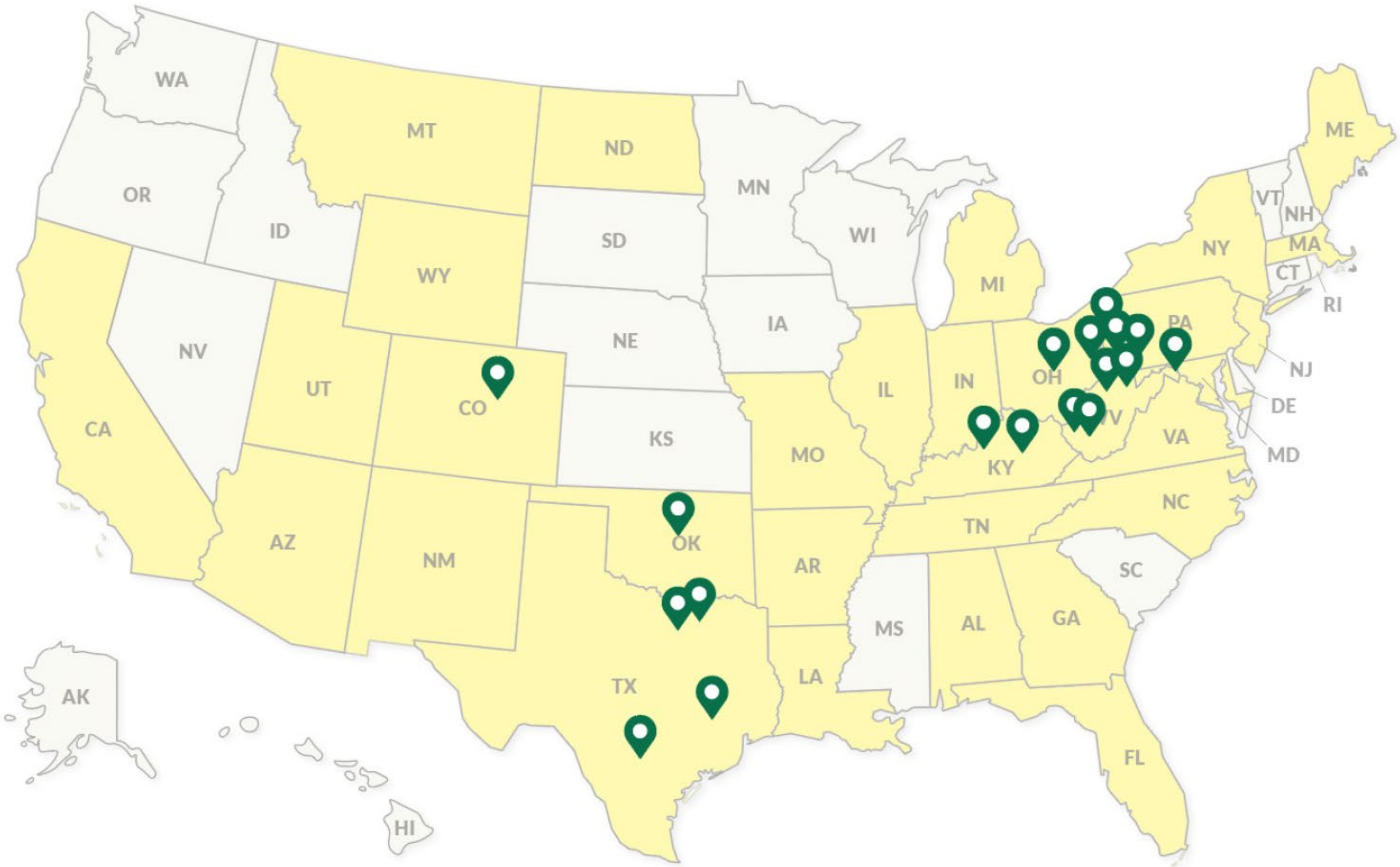
- More than 50 attorneys cross-trained to understand title in multiple states and basins
- $20B+ in recent complex energy transactions

Office Locations & Attorney Licensure



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- The Woodlands, TX
- Wheeling, WV

Attorney Licensure

Agenda

- Is your lease a "lease"?
- Premises (and execution)
  - The "who"
- Granting clause
  - The "where," "what," and "how"
- Habendum clause
  - The "when" and "how long"
- Rentals and royalty clauses
  - The "why" and "how much"
- Administrative clauses
- Implied covenants

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IS YOUR LEASE A "LEASE"?

"Lease"

- "1. 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. The lease term can be for life, for a fixed period, or for a period terminable at will.
- 2. Such a conveyance plus all covenants attached to it.
- 3. The written instrument memorializing such a conveyance and its covenants.
- 4. The piece of property so conveyed."
  - Black's Law Dictionary (11th ed. 2019).

“Leasehold”

- “A tenant’s possessory estate in land or premises, the four types being the tenancy for years, the periodic tenancy, the tenancy at will, and the tenancy at sufferance. Although a leasehold has some of the characteristics of real property, it has historically been classified as chattel real.”
  - Black’s Law Dictionary (11th ed. 2019)

Are All Leases "Leases"?

- OGLs
  - Fee simple determinable
  - Profit a prendre
  - Inchoate right that becomes vested tenancy only after production
  - Term of years (*Hist.*)
- Mining leases
  - Fee simple
  - Term of years
- Renewable leases
  - Term of years
  - Easement
  - ?
- Is renting preferable to owning?

The “who”

PREMISES (AND EXECUTION)

Premises (and Execution)

- Premises must identify the lessor and lessee
  - Parties must be legally competent
- Execution
  - Signature
  - Attestation and acknowledgment
  - Delivery and acceptance
  - Recording

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The "where," "what," and "how"

GRANTING CLAUSE

Granting clause

- Size of the interest granted
  - Proportionate-reduction clause
- Land covered
  - Description
  - Tax parcel identification
  - Mother Hubbard clause
- Substances covered
  - "oil, gas and other minerals" v. "oil, gas and other hydrocarbons"
  - "Sewickley seam of coal" v. "Mapletown seam of coal"
  - Do you lease the wind or the land?
  - Do you lease the sunshine or the land?

Granting clause

- Uses permitted
  - Express rights and implied rights
  - Reasonable use
  - The accommodation doctrine
    - *Lyle v. Midway Solar, LLC*, 618 S.W.3d 857 (Tex. App.—El Paso 2020)
  - For the benefit of which tract
  - In accord with lease terms
  - In accord with statutes, ordinances, rules or regulations
    - OG: surface-damage acts
    - Mining: SMCRA/state equivalents
    - Renewables: zoning/land use planning

The “when” and “how long”

HABENDUM CLAUSE

Habendum clause

- OG:
  - Primary term
    - Payment of delay rentals
  - Secondary term
    - PPQ
      - Litmus test
      - Legal test
    - Constructive-production savings clauses
      - Operations
      - Pooling
      - Temporary cessation of production
      - Shut-in royalty
      - Force majeure

Habendum clause

- Mining leases
  - Term of years
  - Term of years with extensions
  - Term of years unless coal is exhausted earlier
  - Term of years and thereafter until all mineable and merchantable coal is exhausted
  - Term of years and thereafter so long as lessee conducts mining operations
  - Until exhaustion of all mineable and merchantable coal

Habendum clause

- Renewable leases:
  - Development term
    - Like OGL primary term, but often structured as option
  - Construction term
    - Term of years subject to extension
    - Not usually structured as determinable interest
  - Operating term
    - Term of years subject to extension
    - Not usually structured as determinable interest

The “why” and “how much”

RENTALS AND ROYALTY CLAUSES

Rentals and royalty clauses

- OG:
  - Delay rentals
    - "Unless" v. "or" – condition v. covenant
    - Paid-up OGLs
  - Royalty
    - Fraction of production
      - Capture-and-hold v. marketable-product rule
      - Market-value v. proceeds
        - Take-or-pay benefits
    - Flat-rate well rentals
    - Shut-in royalty
  - Other compensation
    - Free gas

Rentals and royalty clauses

- Mining leases:
  - Minimum annual rental or royalty
  - Tonnage or production royalty
  - Wheelage
  - Clean coal v. gross production
- Renewable leases:
  - Initial rent based on acreage – similar to delay rental
  - Subsequent rents
    - Based on acreage
    - Based on power generating capacity (“nameplate capacity”)
    - Other methods of calculation
  - Other compensation
    - Construction payments
    - Surface-disturbance payments

ADMINISTRATIVE CLAUSES

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Administrative clauses

- Warranty clauses
- Lesser-interest (or proportionate-reduction) clauses
- Subrogation clauses
- Equipment-removal/reclamation clauses
- Assignment/sublease clauses
- Notice-of-assignment clauses
- No-increase-of-burden clauses
- Separate-ownership clauses
- Surrender clauses
- Notice-and-demand/notice-before-forfeiture clauses
- Judicial-ascertainment clauses

IMPLIED COVENANTS

Implied covenants

- OG:
  - Reasonable-prudent-operator standard
  - Implied covenants
    - Test
    - Reasonably develop
    - Further exploration
    - Protect against drainage
    - Market
    - Diligent and proper operation

Implied covenants

- Mining leases:
  - Reasonable-prudent-operator standard
  - Implied covenant to develop
    - Majority rule: no implied covenant if lease requires minimum royalty payment
    - Minority rule: implied covenant unless expressly waived
- Renewable leases:
  - ?

Questions?

Disclaimer

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DRAFTING AND NEGOTIATING INSTRUMENTS TO ACQUIRE PORE SPACE RIGHTS FOR CCS

Keith Hall

Drafting and Negotiating Instruments to Acquire Pore Space Rights for CCS

Keith B. Hall
LSU Law School
Baton Rouge, Louisiana
(504) 250-2636
khall@lsu.edu

LSU LAW
JOHN P. LABORDE
ENERGY
LAW CENTER

November 10, 2023
Oklahoma City, Oklahoma

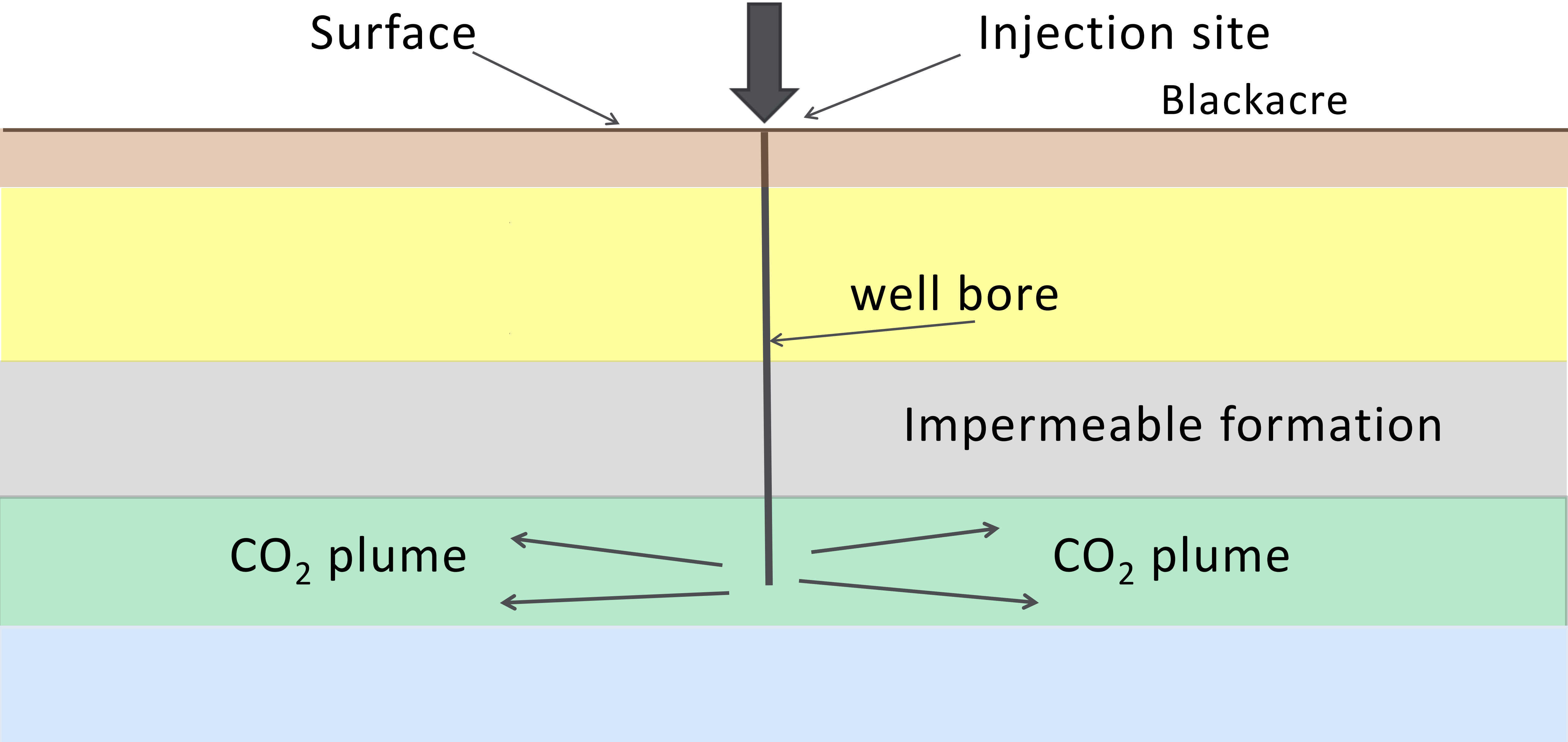
Eugene Kuntz Conference on Natural Resources Law & Policy

Carbon Capture and Storage

Carbon capture and storage involves

- ***Capture*** of ***carbon*** dioxide (CO_2) by separating it from other compounds in a source of gaseous industrial emissions or the atmosphere
- ***Storage*** of the captured CO_2 by injecting it into an underground for permanent sequestration

CO_2 injected into subsurface for storage



Incentives for CCS

- 45Q federal tax credit (with direct pay option which can be useful for entities without tax liability to offset)
- California's Low Carbon Fuel Standard
- Goodwill
- Other state laws

Regulation of injections into subsurface

- CCS wells are regulated under Part C of Safe Drinking Water Act (SDWA), which is designed to protect underground sources of drinking water (USDWs).

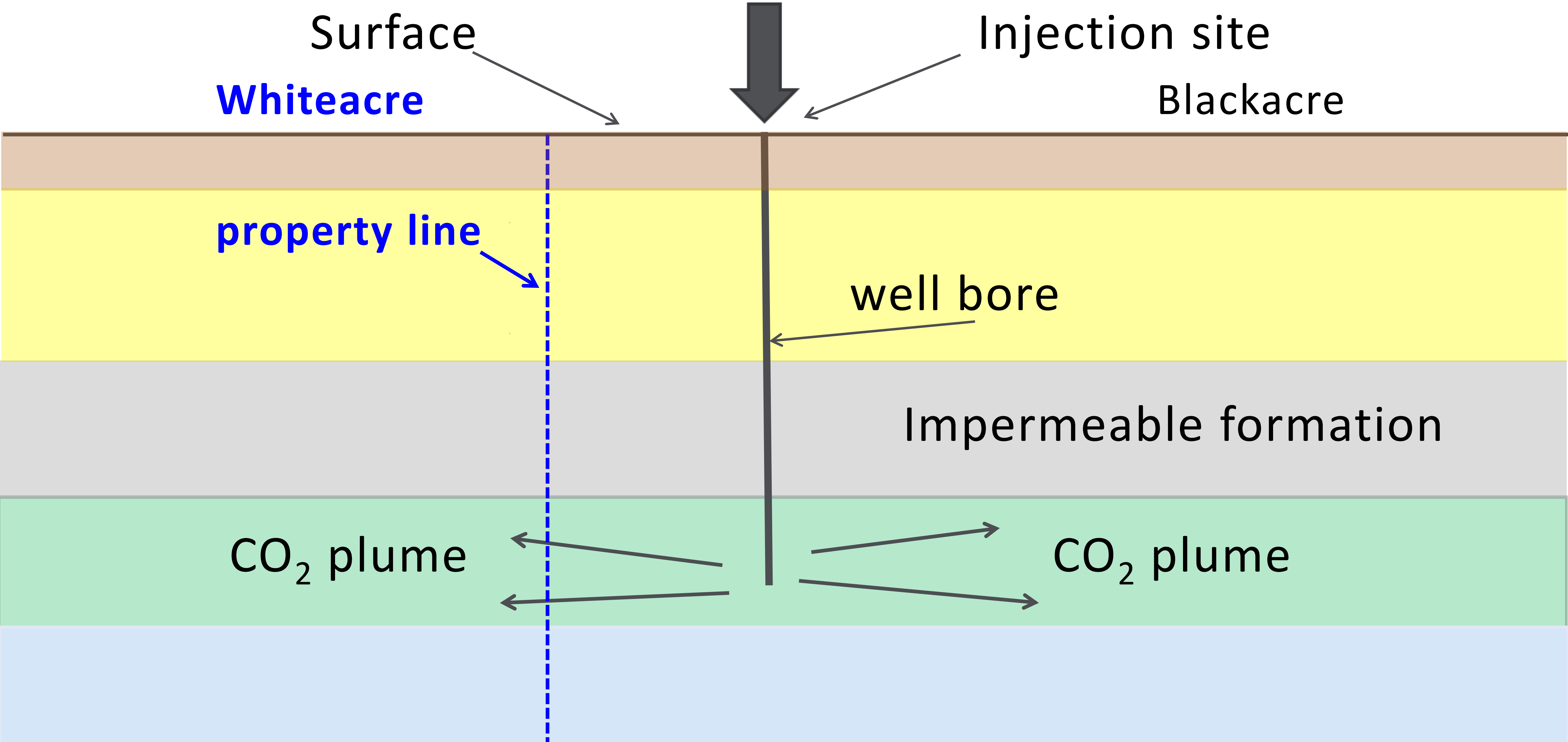
- Pursuant to Part C, EPA has promulgated underground injection control (UIC) regulations.

- The regulations define six classes of injection wells.

- CCS wells are Class VI wells.

Why would a prospective CCS operator need to contract for pore space rights?

Does owner of Whiteacre have redress?

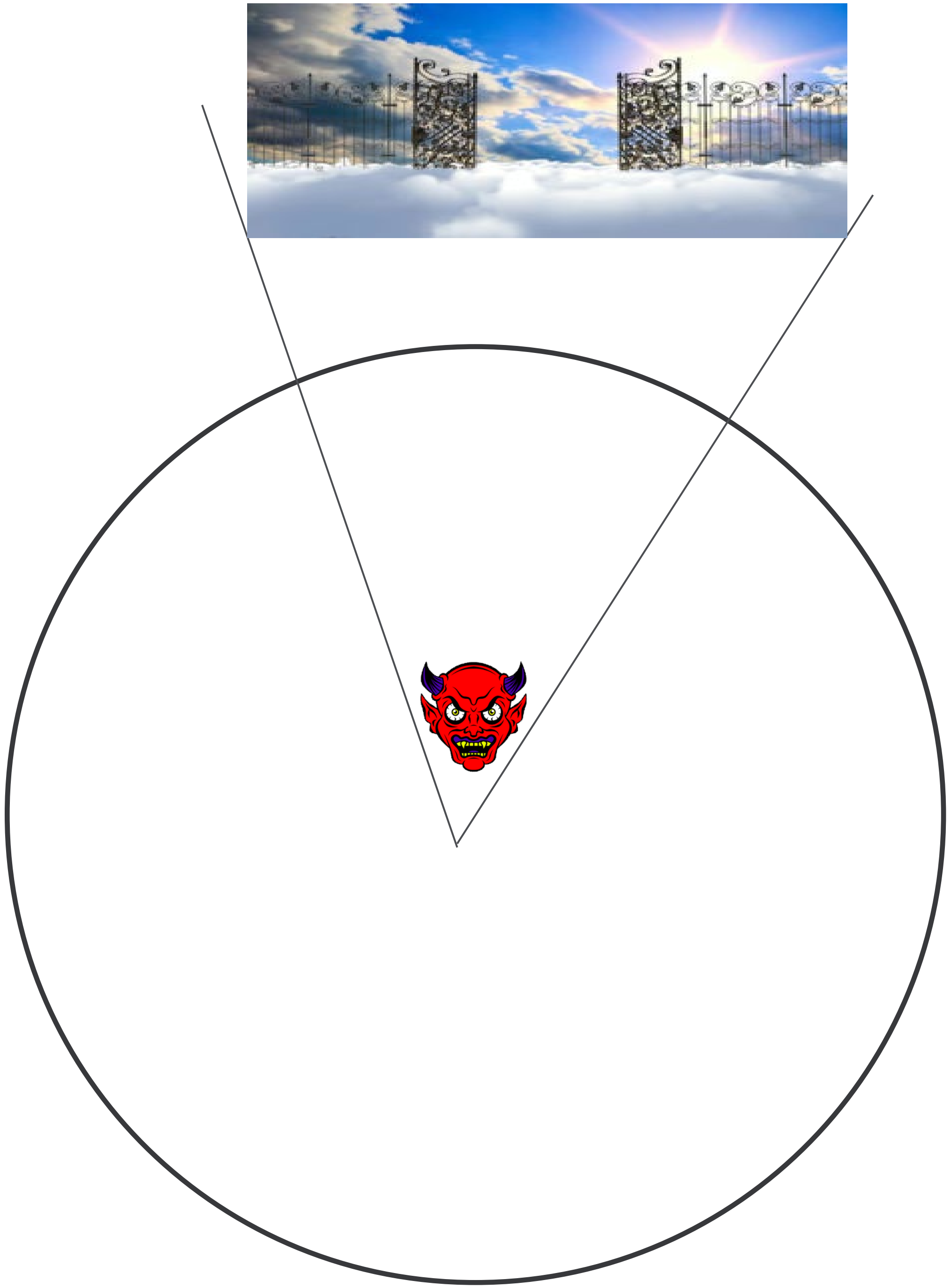


The *ad coelum* doctrine

- “*cujus est solum ejus est usque ad coelum et ad inferos*”

- “For whoever owns the soil, it is theirs up to Heaven and down to Hell.”

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



Ownership and the right to exclude

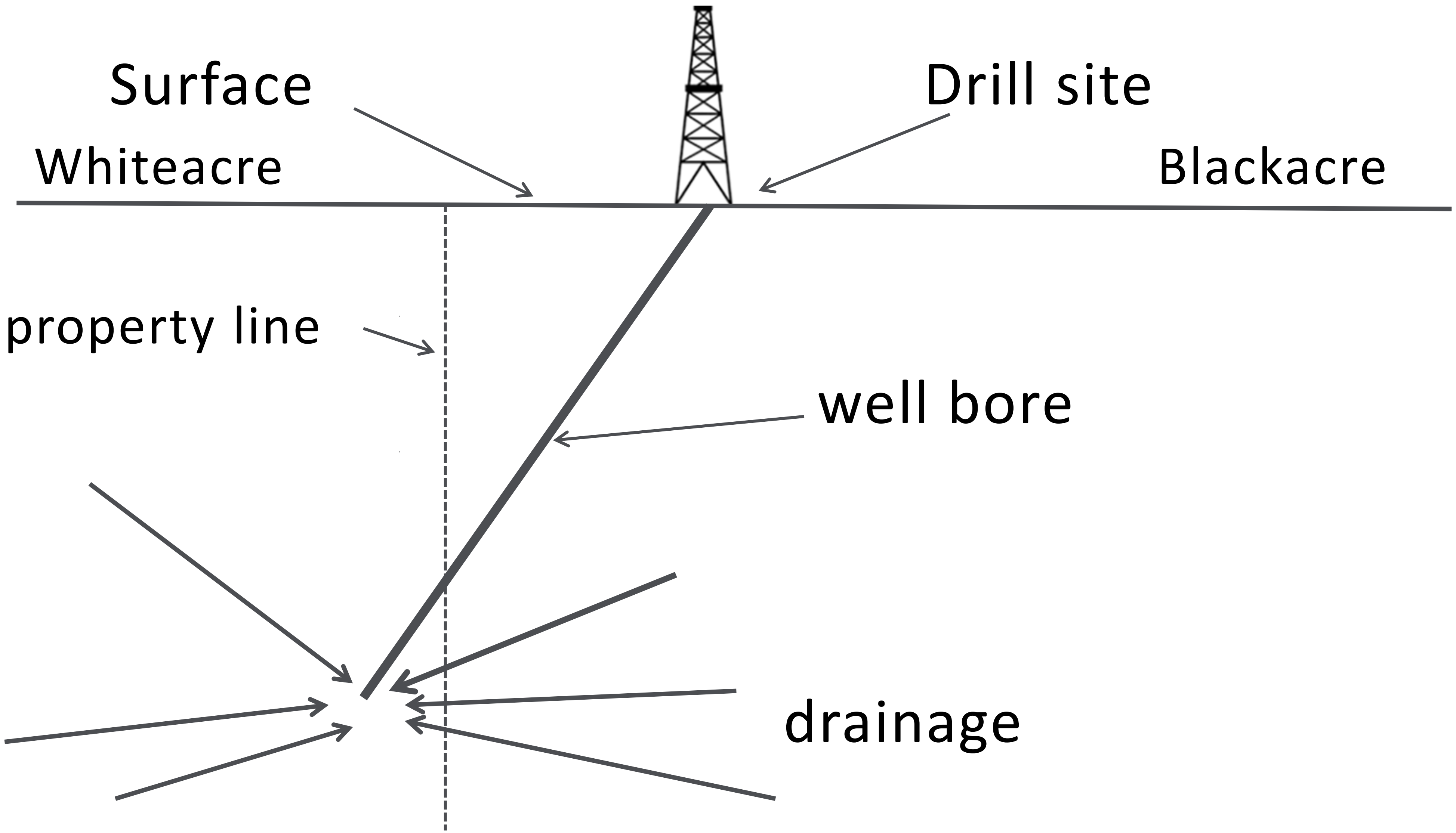
- Ownership includes several benefits.

- One benefit is a right to exclusive possession.

- “Trespass” is an entry onto land that violates the owner’s right to exclude others. [1]

1. *Williamson v. Fowler Toyota, Inc.*, 956 P.2d 858 (Okla. 1998)

Subsurface trespass



Edwards v. Lachman, 534 P.2d 670 (Okla. 1974); *Williams v. Continental Oil*, 14 F.R.D. 58 (W.D. Okla. 1953)

Could subsurface migration of waste fluids constitute trespass?

- Absent harm to a plaintiff, it not clear that the migration of fluids from an injection disposal well will constitute a trespass.

West Edmonds Salt Water Disposal Ass’n v. Rosecrans, 226 P.2d 965 (Okla. 1950)

What if there is a severed mineral estate?

- Who owns subsurface pore spaces—surface owner or mineral owner?
- No definitive answer in most states.
- Just about everywhere, consensus is that surface owner owns pore spaces.
- "Surface owner" seems to be answer in Oklahoma.

Ellis v. Arkansas Louisiana Gas Co., 450 F. Supp. 412 (E.D. Okla. 1978)

What type of contract should be used to acquire pore space rights?

What type of contract?

- Purchase land outright in fee simple?
- Purchase of a storage estate?
- Purchase subsurface storage easement?
- Lease of subsurface pore spaces?

- There seems to be a trend toward using leases.

How is compensation to surface owner structured?

Typical structure of compensation

- Upfront bonus
- Perhaps additional bonuses as CCS project meets certain milestones
- Annual rentals
- Either an injection fee that is based on the number of tons of CO_2 injected or a royalty based on revenue from the CCS operation.
- An injection fee might be indexed to 45Q tax credit.

Texas Lease to Bayou Bend CCS (subsidiary of Talos)

Initial Bonus	**$4.5 million** (after executing lease; lease covers about 40,200 acres, so the bonus equates to **about $110 per acre**)
Second Bonus Payment	**$4.5 million** when CCS operator secures contracts for injection of at 4 million metric tons per year of CO_2
Third Bonus Payment	**$4.5 million** when injections begin
Royalty	• **3% of "Facility Proceeds"** during an Initial Injection Period (this equals **$2.55 per ton** if 45Q tax credit is only revenue) • **6% of Facility Proceeds** during Subsequent Injection Period (this equals **$5.10 per ton** if 45Q tax credit is only revenue)

Louisiana initial payments

1. Air Products	**$50 per acre**
2. Capio Sequestration	**$34 per acre**
3. Venture Global CCS Plaquemines	**$100 per acre**
4. Venture Global CCS Cameron	**$171 per acre**
5. High West Sequestration	**$425 per acre**
6. Castex Carbon Solutions	**$300 per acre**

Louisiana rentals

1. Air Products	**$50 per acre per year** until injections **begin**
2. Capio Sequestration	**$50 per acre per year** until injections **begin**
3. Venture Global CCS Plaquemines	**$50 per acre per year** until injections **end**
4. Venture Global CCS Cameron	**$50 per acre per year** until injections **end**
5. High West Sequestration	**$55 per acre per year** until injections **end**
6. Castex Carbon Solutions	**$60 per acre per year** until injections **end**

Louisiana injection fees

1. Air Products	**$4.65 per ton** plus 9% of any increase in 45Q tax credit, and there is a contractual minimum annual injection fee.
2. Capio Sequestration	**$3.35 per ton** plus 5% of any increase in 45Q tax credit, and there is a contractual minimum annual fee.
3. Venture Global CCS Plaquemines	**$6.50 per ton** plus 10% of any increase in 45Q tax credit, and there is a contractual minimum annual injection fee.
4. Venture Global CCS Cameron	**$6.50 per ton** plus 10% of any increase in 45Q tax credit, and there is a contractual minimum annual injection fee.
5. High West Sequestration	**$7.50 per ton** plus 10% of any increase in 45Q tax credit, and there is a contractual minimum annual injection fee.
6. Castex Carbon Solutions	**$7.50 per ton** plus 10% of any increase in 45Q tax credit, and there is a contractual minimum annual injection fee.

What rights does the CCS operator need?

What rights does CCS operator need?

- Right to conduct geophysical surveys of subsurface
- Right to inject CO_2 and store it in subsurface
- Right to conduct monitoring, including monitoring for migration of CO_2 plume and for presence of CO_2 at surface, for decades after injections cease

* Operator will need surface rights at injection site and along pipeline route.

What depths?

- The agreement should state the formations that CCS operator can use for storage or state the depths that the operator can use for storage.

- Some sources suggest that storage formations likely will be 2600 feet or more beneath surface

Drill-through prohibition?

- Some CCS operators negotiate for a prohibition on anyone drilling through the storage reservoir.

- Possible motivations for this

  - Cannot qualify for California Low Carbon Fuel Standard otherwise

  - Fear that drilling through could result in leakage of CO_2 (45Q tax credit must be repaid if CO_2 escapes)

Who can grant “no-drill-through rights”?

- Generally, only the person who has oil & gas drilling rights can agree to forego that right.

- Thus, if there is severed mineral estate, a CCS operator would need to get the mineral estate owner’s consent to a “no-drill-through” provision.

- If there is an existing and valid oil & gas lease, the CCS operator would need to obtain the lessee’s consent.

Duration of Rights

--

If prospective CCS operator seeks to acquire pore space rights via lease, what should be the duration of the lease?

Duration of Rights—**pre-injection**

1. Operator will need to conduct geophysical studies to obtain info. necessary for Class VI permit application.

   ➢ Most leases allow about 3 years, with a potential for an extension of time, to do this and submit application.

2. It will take time to obtain permit (perhaps 2 years or more), then additional time to construct well.

   ➢ Most leases allow 3 to 4 years, with the possibility for an extension, to do this and begin injections.

Duration of Rights—**injection stage**

- Depending on rate of injection and the size of storage reservoir, the injections may continue for several years.
- Some leases provide that, once injections begin, the lease will last until there is a specified period of time (such as one year) in which no injections take place.
- Others provide for a term with a maximum number of years, such as 30 years.

Duration of Rights—**post-injection**

- Class VI regulations require that surface and subsurface monitoring be conducted for a long time after injections cease.
- Monitoring may need to be done for fifty or more years after injections cease.
- CCS operator will need to contract for monitoring rights to continue for this lengthy period.

Example—Duration of **Texas** CCS agreement

- "Development Term" – up to 3 years to apply for Class VI permit (with possible extension)
- "Construction Term" – up to 3 years to begin injections (with possible extension)
- "Operations Term" – earlier of 30 years or when storage reservoir has reached limit of its capacity
- Right to conduct monitoring required by law continues after Operations Term

Example—Duration of **Louisiana** CCS agreements

- "Initial Term" – up to 3 years to apply for Class VI permit (with possible extension)
- "Permit/Construction Term" – up to 4 years to begin injections (with possible extension)
- "Operational Term" – as long as lessee continues to inject without gap of more than 1 year in injections
- Right to conduct monitoring required by law continues after the Operational Term

Pooling or unitization

Pooling or unitization clause

- If there is chance that CO_2 plume will migrate into subsurface of multiple tracts, the agreement should have the equivalent of pooling or unitization clause.

- Clause should

  - authorize operator to combine the land with other tracts

  - provide for apportionment of whatever compensation is paid for injections/revenue

Other Clauses

Other clauses

Surface owner should bargain for

- Indemnities and defense from CCS operator
- Consider requiring operator to provide insurance
  - Perhaps making surface owner a named insured and requiring insurer to waive subrogation rights
- Bargain for a surface damages and restoration
- Information/audit rights?

Potential Disputes if a Severed Mineral Estate or a Mineral Lease Exist

Increased costs of drilling to depths beneath CCS storage reservoir

Materials of construction for CCS well

- CO_2 in water can be acidic and slightly corrosive.
- A CCS well will use different materials of construction (casing and cement) than is typically used in oil and gas drilling.
- The materials used in CCS well will be more expensive.

Materials of construction for oil & gas well

- If oil/gas well is drilled through CCS storage reservoir, more expensive materials will be needed.
- Would surface owner violate mineral owner’s rights by authorizing a CCS project that makes drilling deep oil and gas wells more expensive?

Accommodation Doctrine

Mineral owner may have duty to accommodate surface owner's existing uses of the land if there are customary and reasonable methods of exploration and production, practiced in the industry, that would avoid interfering with the existing use.

Accommodation Doctrine (1)

- Oil & gas lessee did not have duty to accommodate surface owner by acquiring needed water offsite.

Sun Oil Co. v. Whitaker, 483 S.W.2d 808 (Tex. 1972)

Accommodation Doctrine (2)

- Fact issue as to whether mineral estate owner would have to use slant drilling to accommodate surface owner who decided to flood land for water reservoir.

Tarrant County Water Control & Imp. Dist. v. Haupt, Inc., 854 S.W.2d 909 (Tex. 1993)

Accommodation Doctrine (3)

- B/c mineral owner had no current plans to use its mineral rights, lawsuit against surface owner who planned to put solar panels on most of surface was premature.

Lyle v. Midway Dolar, LLC, 618 S.W.3d 857 (Tex. App.—El Paso 2020)

Geophysical exploration

Need for geophysical exploration

- Safe Drinking Water Act regulations require a person applying for a Class VI permit to provide extensive information about the subsurface.
- This may information from geophysical surveys, such as seismic surveys and perhaps test well logs.
- A mineral lessee or owner of a severed mineral estate may not like the prospective CCS operator performing geophysical surveys.

<u>Right to conduct geophysical exploration</u>

- Does **owner of a severed mineral estate** have exclusive right to conduct geophysical surveys?
- Mineral owner probably does have an exclusive right to conduct geophysical surveys <u>*for the purpose of mineral exploration*</u>.
- What if the surface owner or a CCS lessee has a legitimate purpose for geophysical surveys unrelated to mineral exploration?

Right to do geophysical exploration—*Cowden*

- In *Cowden*, U.S. 5th Circuit held that surface owner had no right to do seismic to explore for minerals because surface owner has no legitimate reason for such work.
- *Cowden* stated in dicta that a mineral lessor’s reversionary right in minerals is sufficient to give lessor legitimate reason to do seismic.
- Of course, lease could expressly give lessee an exclusive right to do seismic for any purposes.

Possible implications of *Cowden*

- Evaluating the subsurface for potential CCS operations is a reason to perform seismic explorations.

- *Cowden* could be used to argue that the surface owner can authorize someone to do seismic exploration to evaluate the suitability of the subsurface for CCS.

Right to geophysical exploration—*Grynberg*

- In *Grynberg*, a severed mineral estate existed and the mineral owner had granted a coal lease.
- The surface owner was considering selling the land to a municipality that wanted to construct a dam and a wastewater reservoir.
- Colorado regulations required anyone applying for a permit to construct a dam that would flood an area to determine whether commercial deposits of coal existed.

Grynberg (2)

- In *Grynberg*, surface owner granted the city permission to do geophysical exploration.

- The city drilled test wells to determine whether commercial deposits of coal existed.

- Co. S. Ct. said that city violated rights of coal lessee.

Grynberg (3)

What if landowner performed geophysical surveys looking for

- a permeable formation that could hold CO_2,
- impermeable formations that could serve as a seal to contain CO_2, and
- any geologic faults that might intersect the permeable and impermeable formations,
- without expressly looking for minerals?

Confidentiality of geophysical surveys

If a severed mineral estate or mineral lease exists,

- **a surface owner should consider** a clause requiring the prospective CCS operator to keep geophysical data confidential and seek to have regulator treat as confidential any such data submitted in SDWA application

- **prospective CCS operator should consider** whether to seek agreement with mineral owner or mineral lessee regarding geophysical data

Publicly available pore space agreements

Publicly available agreements

- Texas has granted CCS lease to Talos for area in Texas waters in the Gulf of Mexico. It is available by public records request from General Land Office.
- As of Oct. 2023, La. has granted six leases. These are publicly available at https://www.dnr.louisiana.gov/index.cfm/page/168
- Wyoming has granted a couple of leases.

The typical oil & gas lease probably authorizes enhanced oil recovery (EOR) operations that incidentally sequester CO_2.

But (not counting EOR) would an oil & gas lease be sufficient to authorize CCS?

Waste disposal authority under oil & gas leases

- Typical lease may implicitly authorize use of leased premises for disposal of oilfield wastes produced from leased premises and land unitized therewith.

- Typical lease generally would not authorize disposal of other types of waste or oilfield wastes produced elsewhere.

- Typical oil & gas lease probably does not authorize CCS unless the CCS operation only accepts CO_2 from a treatment plant that only treats gas produced from leased premises or land unitized therewith.

Alternatives to agreement?

Alternatives to Agreements

- Could the pore spaces be open to free use?
- Eminent domain?
- Unitization?

Eminent Doman

At least two states have authorized a prospective CCS operator to acquire subsurface rights by eminent domain

- Ala. Code § 9-17-154
- La. Rev. Stat. 31:1108

Unitization

Several states have authorized a unitization-like process for CCS.

- Ken. Rev. Stat. 353.808
- Miss. Code § 53-11-9
- Mon. Code § 82-11-204
- Neb. Rev. Stat. 57-1612
- N.D. Cent. Code § 38-22-10
- Utah § 40-11-10
- W. Va. Code § 22-11B-19
- Wyo. Stat. § 35-11-315
- Cal. Pub. Res. Code § 71460

LSU LAW
JOHN P. LABORDE
ENERGY
LAW CENTER

Keith B. Hall
LSU Law School
Baton Rouge, Louisiana
(504) 250-2636
khall@lsu.edu

EXTRA SLIDES

Incentives for CCS

45Q Tax Credit

- Federal tax law in U.S. provides a tax credit for CCS.

- Credit is $80 per ton for CO_2 injected for long term storage and $60 per ton for the net amount of CO_2 injected in EOR (if certain labor standards met).

- If DAC is used, the credit can be $180/ton (if certain labor standards are met) and $130/ton for EOR.

- “Direct pay” from fed gov’t allowed if operator does not have tax liability to offset.

California’s Law Carbon Fuel Standard

- California law creates a financial incentive for the sale of fuels that satisfy the state’s Low Carbon Fuel Standard.

- Some manufactured biofuels can meet the Low Carbon Fuel Standard if CO_2 created during the process of making the biofuel is injected into the ground for permanent storage.

Good will

- Some businesses may be willing to spend money on CCS in order to promote themselves as doing something for the environment.

Other motivations

- If the U.S. ever enacts a “carbon tax” on products and activities that result in the emission of carbon dioxide, companies may have an incentive to use CCS to limit their CO_2 emissions.

5

DRAFTING AND NEGOTIATING INSTRUMENTS TO ACQUIRE PORE SPACE RIGHTS FOR CCS

Keith B. Hall
Louisiana State University Law Center
Baton Rouge, Louisiana

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§ 5.01 Background[*]

Scientists believe[1] that human activities are causing an accumulation of carbon dioxide (CO_2) and other greenhouse gases[2] in the atmosphere, and that this accumulation is causing a change in the world's climate. Scientists warn that the change in climate could be very disruptive to human societies. As one of several policy responses to this risk, the United Nations Intergovernmental Panel on Climate Change

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Keith B. Hall is the Nesser Family Chair in Energy Law at Louisiana State University, where he serves as Director of the Mineral Law Institute and Director of the John P. Laborde Energy Law Center. He teaches Mineral Rights, International Petroleum Transactions, Civil Law Property, and Energy Law & Regulation. Professor Hall is a co-author or editor of four books: (1) *The Law of Oil and Gas*; (2) *International Petroleum Law and Transactions*; (3) *Hydraulic Fracturing: A Guide to Environmental and Real Property Issues*; and (4) *The Regulation of Decommissioning, Abandonment and Reuse Initiatives in the Oil and Gas Industry*. Professor Hall's shorter publications have addressed carbon capture and storage, implied covenants in oil and gas leases, pooling and unitization, joint operating agreements, hydraulic fracturing, induced seismicity, and the management of produced water. Professor Hall has served as an arbitrator, author of amicus briefs, and as an expert witness in oil and gas disputes arising in several different states, as well as outside the United States. Before joining the LSU faculty in 2012, Professor Hall practiced law at a major firm in New Orleans for 16 years, and before that he worked for eight years as a chemical engineer.

[1] Nat'l Energy Tech. Lab'y (NETL), U.S. Dep't of Energy, "Carbon Storage Atlas," at 7 (5th ed. 2015).

[2] Greenhouse gases are gases that trap heat in the atmosphere. *See* U.S. Env't Prot. Agency (EPA), "Overview of Greenhouse Gases," https://www.epa.gov/ghgemissions/overview-greenhouse-gases (also noting CO_2 accounted for 79% of U.S. greenhouse gas emissions in 2020). Other greenhouse gases include methane and hydrofluorocarbons. *Id.*

(IPCC),[3] the U.S. federal government,[4] and several state governments[5] within the United States support the use of carbon capture and storage (CCS).

This chapter focuses the private "pore space agreements" that CCS operators might enter to acquire the right to use subsurface pore spaces beneath land owned by other persons for CCS. Section 5.01 contains background information regarding CCS. Section 5.02 states why the CCS operator needs to obtain pore space rights. Section 5.03 provides a brief discussion of the nature of pore space agreements—that is, whether a CCS operator should acquire fee simple absolute ownership, easement rights, lease rights, etc. Section 5.04 discusses the provisions that should be included in such agreements. Sections 5.05 through 5.08 consider, respectively, alternatives that CCS operators might have for entering contracts for pore space rights, with whom should the CCS operator contract when there is a severed mineral estate, whether an oil and gas lessee could rely on the lease for authority to conduct CCS, and the available information regarding the market price for pore space rights. This chapter will not discuss in any detail the sequestration of CO_2 incidental to enhanced oil recovery or EOR.

To understand the terms and conditions that should be included in pore space agreements, it is important to understand (1) what takes place during CCS and what some of the risks are, (2) what financial incentives exist for CCS, and (3) what is required by the regulatory scheme that governs CCS. The following subsections of this chapter consider these issues.

[1] What Takes Place During Carbon Capture and Storage (CCS)? What Are Some of the Risks?

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[3] IPCC, "Climate Change 2022: Mitigation of Climate Change, Summary for Policymakers," at 28 (2022). The IPCC report calls CCS "a critical mitigation option" for the cement and chemical industries. *Id.* Other authorities agree. The International Energy Agency has stated that "CCUS will be crucial to reduce cement sector CO_2 emissions." Int'l Energy Agency, "Cement" (2022), https://www.iea.org/reports/cement.

[4] *See, e.g.*, 26 U.S.C. § 45Q; Off. of Fossil Energy & Carbon Mgmt., U.S. Dep't of Energy, "Carbon Storage Research," https://www.energy.gov/fecm/carbon-storage-research.

[5] *See, e.g.*, Ala. Code § 9-17-151(a)(2) ("[CCS] . . . is in the public interest and welfare of this state, and is for a public purpose"); La. Stat. Ann. § 30:1102(A)(1) ("[CCS] will benefit the citizens of the state and the state's environment by reducing greenhouse gas emissions"); Miss. Code Ann. § 53-11-3(a) ("[CCS] will benefit the citizens of the state and the state's environment").

In CCS, an operator *captures* CO_2—the *carbon* of carbon capture and storage—by separating it from the other compounds in a gaseous mixture.[6] Typically, the mixture will be the emissions from an industrial source, though there is increasing interest in separating CO_2 from the other compounds in the atmosphere itself in a process called "direct air capture" or "DAC." The purpose of separating CO_2 from the other compounds is to concentrate the CO_2 into a purer stream that has less volume than the original mixture. This way, the operator can handle a smaller volume of gas in the final step of CCS, which involves sending the CO_2 to a disposal well for underground injection and permanent *storage* in the subsurface.

In the final step of CCS, CO_2 will be injected and stored as a supercritical fluid[7]—a phase of matter in which some properties of a fluid (such as density) are similar to a liquid, while other properties (such as viscosity[8]) are similar to a gas.[9] The relatively high density allows a greater amount of CO_2 to be stored in a storage reservoir of a given volume.

For CO_2 to be in a supercritical state, its temperature must be above 88°F and its pressure must be above approximately 1,057 psia.[10] Temperatures and pressures in the subsurface generally increase with depth. At depths 2,600 feet or more beneath the surface, subsurface temperatures and pressures typically are higher than the minimums needed for CO_2 to be in a supercritical state.[11] Thus, most CCS operators likely will use reservoirs at that depth or deeper so that the CO_2 they inject will remain in a supercritical condition.[12]

As CO_2 is injected, the CO_2 will spread laterally within the storage formation. To some extent, the spreading CO_2 plume will push existing formation fluids forward in front of the CO_2 plume. The injections also will cause an increase in pressure in the vicinity of the CO_2 plume. The "pressure front" or area of

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[6] For a discussion of the methods used to separate CO_2 from the other components in a gaseous mixture, see Keith B. Hall, "Carbon Capture and Storage: Models for Compensating Non-consenting Landowners," 14 *San Diego J. Climate & Energy L.* 39 (2023).

[7] NETL, "Carbon Storage FAQs," https://netl.doe.gov/carbon-management/carbon-storage/faqs/carbon-storage-faqs.

[8] Viscosity is a measure of a fluid's internal resistance to flow. *See* Patrick H. Martin & Bruce M. Kramer, *Williams & Meyers, Manual of Oil and Gas Terms* (18th ed. 2021). Cold molasses has a high viscosity. It is a liquid, but it does not pour easily. Liquid water has a lower viscosity and gases tend to have even lower viscosity.

[9] Carbon Storage FAQs, *supra* note 7.

[10] *Id.* The term "psia" stands for "pounds per square inch absolute." It is a measure of pressure.

[11] *Id.*

[12] *Id.*

increased pressure will be wider than the CO_2 plume itself, as the CO_2 pushes other formation fluids outward.

The types of formations that are prime candidates for CCS are saline aquifers and depleted oil and gas reservoirs.[13] The storage formation into which CO_2 is injected will need to have sufficient size, porosity, and permeability to receive the CO_2 to be injected over the life of the CCS operation.[14] Further, to ensure that the CO_2 remains in the storage formation, it is important that the storage formation be surrounded by low permeable formations that will act as a seal or cap rock to keep the CO_2 in place. Further, it will be important that any wells that penetrate the storage formation—including not only the injection well, but also any preexisting or subsequently drilled oil, gas, or disposal wells—be constructed to withstand the pressures and corrosive environment that will be caused by the combination of CO_2 and any water in the formation. Otherwise, CO_2 might escape the storage formation.

The escape of CO_2 from the storage reservoir is undesirable for several reasons. First, as the CO_2 moves in the subsurface, it could carry with it other compounds dissolved into the CO_2. This could include contaminants contained in the CO_2 when it was first injected, or other substances found naturally in the subsurface. This could cause contamination of fluids found in other formations to which the CO_2 migrates after it escapes, potentially including underground sources of drinking water. Further, water commonly exists in the subsurface and a mixture of CO_2 and water will be slightly corrosive, potentially undermining the integrity of any wells that penetrate formations to which escaped CO_2 might migrate.

Also, to the extent, if any, that CO_2 escapes to the atmosphere, the purpose of the CCS operation will be defeated. Moreover, the 45Q tax credits (discussed below) that are one of the main incentives for conducting CCS operations in the United States contains a clawback provision that will require the operator to reimburse the federal government for any tax credits previously obtained on any CO_2 that escapes to the atmosphere.[15] Finally, if a massive amount of CO_2 escapes to the atmosphere (this, however, is probably more likely to occur if there is a rupture of a CO_2 pipeline than a leak from deep underground), it could harm human health. Exposure to CO_2 generally is not harmful, but if a massive quantity reaches the surface at a rate faster than the CO_2 can disperse, it might displace the air and the oxygen it contains, thereby acting as an asphyxiant.[16]

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[13] *Id.*

[14] *Id.*

[15] 26 U.S.C. § 45Q(f)(4); 26 C.F.R. § 1.45Q-5.

[16] In February 2020, a 24-inch diameter CO_2 pipeline owned by Denbury Gulf Coast Pipelines, LLC, ruptured near Satartia, Mississippi, after heavy rains caused a landslide that damaged a pipeline weld.

[2] Incentives for Doing CCS

In the United States, the main incentive for doing CCS is the "45Q" federal income tax credit[17] that the U.S. Congress enacted several years ago. In the Inflation Reduction Act[18] Congress recently increased the tax credit amounts and took steps to make the credits easier to use, such as by providing for the possibility of "direct pay" (payments from the federal government to entities that earn 45Q tax credits in excess of taxable earnings).

But other incentive programs could also provide economic benefits for CCS operators. One example is the California Low Carbon Fuel Standard, which "is designed to decrease the carbon intensity of California's transportation" system.[19] This provides economic incentive for earning "credits" in various ways. One potential way to earn credits is to manufacture biofuels whose life cycle CO_2 intensity is low because the manufacturing process is paired with a CCS project. Such credits can be earned for fuels manufactured outside California, but used in the state.

There are other potential economic benefits. The United States does not currently have a tax on CO_2 emissions, but might one day. Also, perhaps some companies that wish to portray themselves as "climate friendly" might pay a CCS operator to conduct "offset" operations. Further, it is possible that at some point in the future regulatory restrictions on CO_2 emissions might prohibit or effectively prohibit the operation of certain industrial facilities unless they are paired with a CCS project that will permanently store CO_2 generated by the industrial facilities. In such cases, the CCS project might make the continued (and hopefully profitable) operation of the industrial facilities possible.

[3] Applicable Regulatory Scheme

Several environmental laws could apply to CCS operations,[20] but the Safe Drinking Water Act (SDWA) is particularly relevant because Part C of the SDWA includes an underground injection control (UIC) program that is specifically designed to regulate underground injections, with the goal of protecting

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Atmospheric conditions and topographical features delayed the natural dissipation of the CO_2 that leaked. Forty-five persons were taken to the hospital. No fatalities were reported. *See* Pipeline and Hazardous Materials Safety Admin., U.S. Dep't of Transp., "Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/Natural Force Damage" (May 26, 2022).

[17] 26 U.S.C. § 45Q.

[18] Pub. L. No. 117-169, 136 Stat. 1818 (2022).

[19] Cal. Air Res. Bd., "Low Carbon Fuel Standard," https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard.

[20] These include the Clean Water Act, the Clean Air Act, the Endangered Species Act, and the National Environmental Policy Act, among others.

underground sources of drinking water (USDW).[21] The SDWA regulations recognize six classes of injection wells.[22] For purposes of CCS, three of these are most relevant:

- Class II wells,[23] which include wells for secondary or tertiary (enhanced) recovery of oil, and for the disposal of produced water;
- Class V wells,[24] a catch-all category that includes injection wells that do not fit within Classes I through IV[25] or Class VI (this can include test wells drilled for acquiring geophysical data or for monitoring CCS operations); and
- Class VI wells,[26] which are wells for the permanent storage of CO_2.

A company must acquire a SDWA permit before drilling and operating an injection well. The regulator that considers permit applications will be the U.S. Environmental Protection Agency regional office whose jurisdiction includes the state where the well would be drilled, unless that state has "primacy"[27] for the particular class of wells for which the applicant seeks a permit. Numerous states have primacy for Class II and Class V wells,[28] but at present only Wyoming[29] and North Dakota[30] have primacy for Class VI wells. Several other states are seeking or plan to seek primacy for Class VI wells.[31]

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[21] 42 U.S.C. § 300h(a)–(b).

[22] 40 C.F.R. § 144.6.

[23] *Id.* § 144.6(b).

[24] *Id.* § 144.6(e).

[25] Classes I, II, III, and IV are established, respectively, by 40 C.F.R. § 144.6(a), (c), and (d).

[26] *Id.* § 144.6(f).

[27] For a discussion of primacy, see Keith B. Hall, "Regulation of Hydraulic Fracturing Under the Safe Drinking Water Act," 19 *Buff. Envtl. L.J.* 1, 11–13 (2011).

[28] Part 147 of Title 40 of the Code of Federal Regulations details which states have primacy for which classes of UIC wells. The EPA webpage, "Primary Enforcement Authority for the Underground Injection Control Program," https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0, summarizes, using a map and a chart, which states have primacy for which classes of wells.

[29] 40 C.F.R. § 147.2550.

[30] *Id.* § 147.1751.

[31] Louisiana is the state whose pending Class VI primacy application is furthest along. Recently, the EPA published a proposal in the *Federal Register* to grant Louisiana's primacy application. State of Louisiana Underground Injection Control Program; Class VI Program Revision Application, 88 Fed. Reg. 28,450 (proposed May 4, 2023) (to be codified at 40 C.F.R. pt. 147).

To acquire a Class VI permit, an applicant must submit a significant amount of subsurface data.[32] The acquisition of this information likely will require seismic testing and the logging of test wells.[33] Further, during injections, the CCS operator will have to monitor the spread of the CO_2 plume in the subsurface[34] and groundwater quality above the confining zone,[35] and may have to monitor the surrounding area for the presence of CO_2 at the surface,[36] to help verify that CO_2 is not escaping. In addition, for as many as 50 years after injections cease, the CCS operator will have to continue monitoring.[37]

§ 5.02 Why the CCS Operator Needs to Acquire Pore Space Rights

One of the traditional benefits of land ownership is the right to exclude others.[38] The tort of trespass protects this right by giving landowners a claim against persons who enter the land without having a right to do so.[39] The relief available to a landowner can include a monetary judgment for any actual damages

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[32] *See* 40 C.F.R. § 146.82.

[33] Federal regulations require the permit application to include information on the geologic structure and overlying formations; the "location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s)"; information on the depth, thickness, mineralogy, porosity and permeability of the injection and confining zones, "based on field data which may include geologic cores, outcrop data, seismic surveys, [and] well logs"; and various other subsurface information. *Id.* § 146.82(a).

[34] *Id.* § 146.90(g).

[35] *Id.* § 146.90(d).

[36] *Id.* § 146.90(h).

[37] *Id.* § 146.93.

[38] Cedar Point Nursery v. Hassid, 141 S. Ct. 2063, 2072 (2021); Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39, 46 (Tex. 2017); Sammons v. Am. Auto. Ass'n, 912 P.2d 1103, 1105 (Wyo. 1996).

[39] Liability for trespass is based on entering land "in the possession of the other." *Restatement (Second) of Torts* § 158 (1965).

caused by a trespasser,[40] nominal damages to vindicate the landowner's rights when there are no actual damages,[41] and injunctive relief to enjoin a continuing or repeated trespass.[42]

Further, the common law's ad coelum doctrine states that a landowner owns the airspace above it to an indefinite height and the subsurface below it, all the way to the center of the earth.[43] This doctrine's 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.[44] The combination of trespass land and the ad coelum doctrine suggests that a person could incur liability for an unauthorized intrusion into the subsurface of a landowner's property.

Notwithstanding these legal doctrines, it is not clear in most jurisdictions whether an operator would incur trespass liability for injection operations that cause fluids to migrate into the subsurface of a non-consenting landowner's property without causing harm. 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 chapter because it has been thoroughly discussed elsewhere.[45] Further, given the high costs of CCS projects, and

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[40] Smith v. Carbide & Chems. Corp., 226 S.W.3d 52, 55 (Ky. 2007); Whitten v. Cox, 799 So. 3d 1, 18 (Miss. 2000).

[41] Coastal Oil & Gas Corp. v. Garza Energy Trust, 268 S.W.3d 1, 12 n.36 (Tex. 2008) (noting that, in trespass against a possessory interest, actual damages are not necessary and that nominal damages are available); *Whitten*, 799 So. 3d at 18 (reversing lower court's judgment failing to award any damages for trespass, rendering judgment for $10 as nominal damages).

[42] Gilbert Wheeler, Inc. v. Enbridge Pipelines (E. Tex.), L.P., 449 S.W.3d 474, 478 n.1 (Tex. 2014); City of Providence v. Doe, 21 A.3d 315, 319 (R.I. 2011); Hobbs v. Mobile Cnty., 72 So. 3d 12, 17 (Ala. 2011); Donahue Schriber Realty Grp., Inc. v. Nu Creation Outreach, 181 Cal. Rptr. 3d 577, 583 (Ct. App. 2014).

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

[44] 2 William Blackstone, *Commentaries*.

[45] *See, e.g.*, Owen L. Anderson, "Lorde Coke, the Restatement, and Modern Subsurface Trespass Law," 6 *Tex. J. Oil Gas & Energy L.* 203 (2010–2011); Owen L. Anderson, "Geologic CO_2 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 & 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. Resources J.* 361 (2014); 1 Patrick H. Martin & Bruce M. Kramer, *Williams & Meyers, Oil and Gas Law* § 228 (2022).

the real possibility that a subsurface migration of CO_2 could trigger subsurface trespass liability if the CCS operator has not acquired pore space rights, it seems highly unlikely that any prospective CCS operator will pursue a CCS project without obtaining subsurface pore space rights for the areas where its CO_2 is likely to migrate.

§ 5.03 What Should Be the Nature of the Agreement for Subsurface Rights?

A prospective CCS operator could attempt to acquire fee simple absolute ownership[46] of the land (1) on which it will conduct operations; (2) beneath which the CO_2 plume is projected to spread; and (3) even the larger area beneath which the CO_2 injections will create an elevated pressure front, though the CO_2 is not projected to spread that far. But that would be expensive, and, much like a mineral lessee, the CCS operator does not need the full bundle of rights that comes with fee simple absolute ownership. A CCS operator might wish to acquire ownership of the area where the operator will drill the main injection well, but ownership probably is not necessary even for that location.

The CCS operator merely needs the right to use a subsurface formation for storage of CO_2, limited rights to use the surface, and limited restrictions on the landowner's activities to ensure the landowner's activities do not interfere with CCS operations. Accordingly, the CCS operator will seek to enter a pore space agreement by which it obtains the needed rights in land owned by some other person. An initial issue to resolve is the nature of the pore space agreement—will it be a lease or an easement (or perhaps some other form of agreement). Either option—a lease or an easement—could be crafted to include the particular rights that a CCS operator needs. CCS pore space agreements are a sufficiently new phenomenon that there is not yet a standard practice or consensus as to whether the agreement should be a lease or an easement. The publicly-available agreements seem to all take the form of leases, but the author has firsthand knowledge of parties having seriously considered the option of an easement, and he has heard secondhand accounts of pore space rights that have been granted in the form of easements. Moreover, in the context of subsurface storage of natural gas, landowners sometimes have voluntarily granted easements,[47] and companies have used eminent domain provisions of the Natural Gas Act or similar state laws to acquire subsurface storage easements.[48]

[46] "Fee simple absolute," sometimes shorted to "fee simple" or "fee," means an "estate of indefinite or potentially infinite duration." *See Black's Law Dictionary* (11th ed. 2019). In Louisiana, the analogous concept is simply called "ownership." *See* La. Civ. Code Ann. art. 477.

[47] *See, e.g.*, Wilcox v. Nat. Gas Storage Co., 182 N.E.2d 158 (Ill. 1962).

[48] *See, e.g.*, WBI Energy Transmission, Inc. v. Subsurface Easements for the Storage of Nat. Gas, No. 1:18-cv-00088, 2020 WL 9775175 (D. Mont. July 6, 2020); Dominion Transmission, Inc. v. An

§ 5.04 Issues and Provisions to Consider for Pore Space Agreements for CCS

The following subsections of this chapter consider such issues as: (1) what rights will a CCS operator need; (2) how will CCS operations interact with mineral ownership and development (and how might this affect pore space agreements); (3) the duration of pore space agreements; (4) how compensation should be structured; (5) the possibility of a "reasonable diligence" clause; (6) providing for "pooling-like" situations in which multiple tracts of land are used for a CCS project; and (7) surface use and damage issues.

[1] What Rights Will the CCS Operator Need?

Before a company undertakes CCS operations, it will need a Class VI permit under the SDWA. An application for such a permit must include extensive information regarding the subsurface. To acquire this information, the CCS operator typically will need to drill stratigraphic test wells to collect cores and run well logs, and will need to conduct seismic exploration to map the subsurface geology. Accordingly, the CCS operator will need the right to engage in those activities.

If the prospective CCS operator obtains a Class VI permit and constructs a CCS project, the operator will need the right to drill an injection well and construct pipelines to bring CO_2 to the injection well. The operator also will need to drill monitoring wells to help track the spread of the CO_2 plume. In addition, because the injected CO_2 will spread laterally, the CCS operator will need the right to use the subsurface of neighboring tracts for the permanent storage of CO_2. Further, because the spreading plume of CO_2 will cause an increase in pressure—a "pressure front"—in an area beyond the plume. Moreover, to satisfy its monitoring obligations, the operator may need the right to enter the land in the area at various locations to test for the presence of CO_2 at the surface. And, because the operator's monitoring obligations will continue for decades after the operator ceases injections, the operator will need for these rights to continue for a lengthy period.

Finally, SDWA regulations might require the CCS operator to take corrective action at any existing wells within the area to be affected by the CCS operations to ensure that those wells do not provide a pathway for CO_2 to escape to the atmosphere or underground sources of drinking water. The need for corrective action could apply to orphan wells that have never been plugged and abandoned, to previously

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Exclusive Easement to Use the Oriskany Formation, No. 6:16-cv-06693, 2018 WL 692103 (W.D.N.Y. Feb. 2, 2018); Stephens Prod. Co. v. Larsen, 2017 OK 36, 394 P.3d 1262; Hardy Storage Co. v. An Easement to Construct, Operate & Maintain 12-Inch & 20-Inch Gas Transmission Pipelines, Nos. 2:06-cv-00007, 2:07-cv-00005, 2009 WL 900157 (N.D. W. Va. Mar. 31, 2009); *see also* Columbia Gas Transmission Corp. v. Exclusive Gas Storage Easement, 776 F.2d 125, 129 (6th Cir. 1985); Nat. Fuel Gas Supply Corp. v. 138 Acres of Land, 84 F. Supp. 2d 405 (W.D.N.Y. 2000); Columbia Gas Transmission Corp. v. An Exclusive Nat Gas Storage Easement, 620 N.E.2d 48 (Ohio 1993).

plugged and abandoned wells whose structural and construction integrity might not be sufficient to reliably prevent a leak of CO_2, and potentially even to operating wells whose construction standards are not, in the opinion of the regulator, sufficient to reliably prevent a leakage of CO_2. The CCS operator will need the right to enter the surface of the lands where such wells are located and take any corrective action that is required.

[2] Relation of CCS Rights to Mineral Rights

A CCS operation could interact with a mineral owner's rights to explore for and produce minerals in several ways. Some of these are discussed below.

[a] Surface Use Rights

Just as there can be disputes between the surface owner and a mineral owner regarding use of the surface, surface use disputes could arise between a CCS operator and a mineral owner. Absent express contractual provisions (or surface use statutes) that are binding on both the CCS operator and mineral owner, any surface use disputes likely would be resolved by the legal doctrines relating to the mineral owner's implied easement to use the land[49] and the accommodation doctrine.[50] Potential disputes also could arise between the CCS operator and the landowner. The CCS operator should seek to specify surface use rights in its agreement with the landowner. And, if there is a severed mineral estate, the CCS operator may wish to seek a surface use agreement with the mineral owner.

[b] Use of the Storage Reservoir

It probably would be impossible for the CCS operator to use as a storage reservoir the same formation as a mineral owner is using to extract minerals. Presumably, the CCS operator will choose for injection a formation that appears to have no value for the production of oil or gas. This will minimize the likelihood of conflict, but the CCS operator may wish to seek a waiver from the mineral owner (or from the landowner if there is not a split estate) of the right to produce minerals from the storage reservoir.

[c] Drill-Through Rights

An interesting issue concerns the possibility that the mineral owner will seek to explore for and produce minerals from formations beneath the storage reservoir.

It is possible to drill into or through a high-pressure formation without the fluids in that formation escaping from the formation, much less escaping to the surface. Indeed, every time oil and gas operators drill into a high-pressure formation without losing well control they demonstrate that such fluids need not

[49] Numerous authorities discuss the lessee's implied "surface easement." *See, e.g.*, *Williams & Meyers*, *supra* note 45, §§ 218.4–.8.

[50] A leading case on the accommodation doctrine is *Getty Oil Co. v. Jones*, 470 S.W.2d 618 (Tex. 1971). *See also Williams & Meyers*, *supra* note 45, § 218.8.

escape to the surface or to other formations when drilling penetrates such formations. Further, it is not uncommon for the owners of working interests to sever interests by depth, with one person holding deep rights and the other person holding shallow rights. In such circumstances, it typically is understood that the person with shallow rights can drill to any formation within a specified distance from the surface.[51]

Thus, it would be possible for an oil and gas operator to drill through a storage reservoir without causing a loss of CO_2 from the reservoir. Nevertheless, some CCS operators will desire a binding agreement that prohibits the landowner or any other persons from drilling through the storage reservoir. There are at least two reasons why a CCS operator might seek such a waiver of any "drill-through rights" that the landowner or a severed mineral interest owner otherwise might have.

First, some CCS operators will use their CCS operation in conjunction with a petroleum refinery or a facility making alternative fuels—such as biodiesel—to earn credits under California's Low Carbon Fuel Standard. But to earn such credits for CCS, the operator must have a binding agreement that prohibits anyone from drilling through the CO_2 storage reservoir.[52]

Second, although it is possible to drill through a reservoir without allowing an escape of fluid from that reservoir, the process of drilling a well through a reservoir, as well as the continuing existence of the wellbore that penetrates the reservoir, creates a potential for the escape of fluids from the reservoir. This could prove costly. The 45Q tax credit that provides one of the main incentives for conducting CCS operations contains a "clawback" or "recapture" provision, under which a taxpayer that has claimed a 45Q tax credit retroactively forfeits that credit if CO_2 escapes from the storage reservoir.[53] Further, if a massive

[51] The depth limitation might be described as a certain number of feet below a reference point (sea level or the earth's surface or the top or base of a particular formation, etc.) or as the top or base (bottom) of a particular formation. *See, e.g.*, Tim George, Austin W. Brister & Marcus V. Eason, "A Survey of Depth Severance Issues and Related Drafting Considerations," 63 *Rocky Mt. Min. L. Inst.* 30-1 (2017).

[52] The no-drill-through requirement is stated in the California Air Resources Board's August 13, 2018, *Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard*, at section C ("Permanence Requirements for Geologic Sequestration"), subsection 9 ("Legal Understanding, Contracts and Post-Closure Care"). The requirement reads: "The CCS Project Operator must show proof that there is binding agreement among relevant parties that drilling or extraction that penetrate the storage complex are prohibited to ensure public safety and the permanence of stored CO_2."

[53] The tax code refers to the clawback or forfeiture of the tax credit as a "recapture." Section 45Q of the Internal Revenue Code states in part: "The Secretary shall, by regulations, provide for recapturing the benefit of any credit allowable under subsection (a) with respect to any qualified carbon oxide which

leak occurred, it could result in harm to individuals or animals. Direct exposure to CO_2 is generally not harmful—indeed, CO_2 is the "carbonation" in carbonated beverages and in the air we breathe out—but if the quantity and concentration of CO_2 was sufficient to displace the air in an area, rather than simply dissipating into the air, the CO_2 could be an asphyxiant.[54]

The concerns that might prompt a CCS operator to seek "no-drill-through" rights would not be implicated by directional drilling to a bottom-hole location beneath the storage reservoir, assuming that the drilling avoids the storage reservoir altogether. In some cases, the storage reservoir may cover a large enough area that it would not be practical to directionally drill from a location beyond the footprint of the storage reservoir. Thus, in some cases, a CCS operator's acquisition of no-drill-through rights would preclude any development of minerals located beneath the storage reservoir.

If there is not a severed mineral estate, and the CCS operator wants no-drill-through rights, the operator will need to include an express provision for that in the pore space agreement with the landowner. Otherwise, the landowner probably will retain drill-through rights. If a severed mineral estate exists and it has been recorded in the public records, the landowner probably cannot waive the mineral owner's drill-through rights. Thus, if a severed mineral estate exists, a CCS operator that wants no-drill-through rights probably will need to enter a contract with the owner of the severed mineral estate to acquire such rights.

[d] Increased Expense of Drilling Through a CO_2 Storage Formation

If the CCS operator does not obtain no-drill-through rights, the landowner or owner of a severed mineral estate still would have the right to drill through the storage formation to explore for and produce minerals from beneath a CCS storage reservoir. However, drilling though a CCS storage reservoir may be more expensive than other drilling because the regulator might require that the operator drill the oil and gas well consistent with Class VI standards when drilling the portion of the oil or gas well that passes through the storage reservoir. The Class VI standards probably will be more expensive.

A major reason for this is that water is commonly present in the subsurface, and carbonated water is mildly corrosive. Accordingly, Class VI well construction standards will require the use of materials that are corrosion-resistant. This can increase the costs of both the metal used for the well casing and the cement

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ceases to be captured, disposed of, or used as a tertiary injectant in a manner consistent with the requirements of this section." 26 U.S.C. § 45Q(f)(4). The regulation relating to the recapture of the 45Q tax credit is found at 26 C.F.R. § 1.45Q-5. The reference to "carbon oxide" in this footnote is not an error. The tax credit applies to "carbon oxide"—which can include both CO_2 and carbon monoxide—though the credit is primarily aimed at CO_2. *See* 26 U.S.C. § 45Q(c).

[54] This risk is illustrated by the incident described in note 16, *supra*, in which the rupture of a 24-inch diameter CO_2 pipeline in Mississippi resulted in 45 people being taken to the hospital.

used to help seal the well. Thus, although the pore space agreement may not preclude drilling through the storage reservoir, doing so will be more expensive than if there was no CCS operation. This could decrease the value of the "deep rights" to minerals below the storage reservoir. A landowner who owns the mineral rights associated with the land should consider this fact when granting pore space rights.

If a severed mineral estate exists, the possibility that CCS operations will increase the costs of drilling—at least for formations beneath the CCS storage reservoir—raises the possibility that the mineral owner will claim that the landowner's grant of pore space rights and the CCS operator's construction and operation of a CCS facility is an improper interference with the mineral owner's right to explore for and produce minerals. The CCS operator should consider whether it should seek an agreement with the owner of a severed mineral interest in which the mineral owner waives any right to complain about increased drilling costs.

[e] Geophysical Issues

An applicant for a Class VI permit will need to present extensive subsurface information to the regulator to demonstrate that the storage reservoir has sufficient size, porosity, and permeability to receive the CO_2 to be injected, and that the CO_2 will be contained within the storage formation by impermeable formations above and around (the area that would be affected by the CCS project). The prospective CCS operator probably will need to acquire such information from seismic studies and well logging in test wells. This may create conflicts with the owner of a mineral estate.

When a severed mineral estate exists, the mineral owner typically has the exclusive right to explore for and produce oil and gas. The surface owner typically will have no such right. As a general rule, a person who has the exclusive right to explore for and produce oil and gas using a particular tract probably has an implied right to conduct geophysical exploration, such as seismic exploration and the drilling and logging of test wells for purposes of evaluating the prospects of producing oil and gas from the subsurface.[55] It is not clear that this right is exclusive, absent an express provision granting exclusive in the mineral deed or mineral lease that transfers rights to the mineral owner. Some authorities suggest that it would not be exclusive,[56] while other authorities suggest that it is exclusive,[57] and at least one authority suggests that the

[55] *See Williams & Meyers*, *supra* note 45, § 218.5.

[56] Mustang Prod. Co. v. Texaco, Inc., 549 F. Supp. 424, 425–26 (D. Kan. 1982); Ready v. Texaco, Inc., 410 P.2d 983 (Wyo. 1966); Yates v. Gulf Oil Corp., 182 F.2d 286 (Tex. 1950).

[57] *See Williams & Meyers*, *supra* note 45, § 218.6; *see also* Phillips Petroleum Co. v. Cowden, 241 F.2d 586 (5th Cir. 1957).

right is automatically exclusive for a mineral estate owner, but is not exclusive for a mineral lessee unless the lease so provides.[58]

If the right to conduct geophysical exploration is "exclusive," it may be an exclusive right to use the land to conduct geophysical exploration for purposes of evaluating the area for purposes of mineral development. That is, if some person other than the mineral owner has a legitimate reason for conducting geophysical exploration that is independent of developing the area for minerals, the mineral owner's "exclusive" right might not preclude that other person from conducting geophysical exploration for that other legitimate purpose. However, some mineral owners have argued that they have an exclusive right to conduct geophysical operations, without regard to the purpose, if the geophysical exploration might yield results useful for evaluating the tract's potential for mineral production.

Indeed, some authorities have stated that the mineral owner has the exclusive right to conduct or authorize geophysical exploration.[59] Although such statements should not be lightly dismissed by prospective CCS operators, such statements typically have been made in a context in which the authority was contemplating that geophysical exploration for the purpose of evaluating an area for its oil and gas potential.[60] Thus, such statements would be dicta in the context of someone who wishes to conduct

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[58] *Cowden*, 241 F.2d at 591–92. Presumably, the instrument that creates the severed estate could reserve a right for the surface owner to conduct geophysical exploration for minerals if the instrument did so expressly.

[59] Grynberg v. City of Northglenn, 739 P.2d 230, 234 (Colo. 1987); *Cowden*, 241 F.2d at 592; Earl A. Brown, Jr., "Geophysical Trespass," 3 *Rocky Mt. Min. L. Inst.* 57, 59 (1957).

[60] For example, in *Grynberg*, the Colorado Supreme Court described the issue as "whether the owner of a surface estate in a parcel of land can authorize a third party's exploration of that land for minerals when the surface and mineral estates are separately owned." 739 P.2d at 234. Indeed, *Grynberg* seemed to adopt a definition of "geophysical exploration" that presumed the exploration was being done to evaluate the potential for mineral production. *Id.* at 234 n.2. Given this definition of "geophysical exploration," even the court's seemingly broad statement that a mere surface owner cannot authorize geophysical operations could be read as meaning only that a mere surface owner cannot authorize geophysical exploration that is to be undertaken for the purpose of mineral exploration.

In *Cowden*, the Fifth Circuit (applying Texas law) accepted the trial court's finding that the defendant's seismic surveys "constituted investigation and exploration for oil, gas and other mineral purposes" and "were reasonably expected to reveal geophysical and geological information . . . as to the . . . land involved in this action." 271 F.2d at 590–91.

geophysical operations for some reason other than evaluating the land's potential for mineral production. Accordingly, if a surface owner (or a third person claiming rights through the surface owner) has a legitimate reason other than mineral exploration for conducting geophysical operations—such as seismic exploration, drilling and logging test wells, or some other type of geophysical operation—a court might conclude that the surface owner may conduct or authorize such geophysical evaluations of the land without consent of the owner of the mineral estate.

Consider the fact that a mineral estate owner typically has a right to build roads on the land, if the roads are reasonably necessary to facilitate the exploration for or production of oil and gas. No one would describe this as an exclusive right because it is obvious that the landowner has legitimate reasons—reasons wholly unrelated to mineral development—for building roads.

Consider also that, although a mineral estate owner has an exclusive right to drill wells *for the purposes of exploring for and producing oil and gas*, the mineral owner typically does not have an exclusive right to drill wells. A landowner typically will have the right to use groundwater from beneath his or her land. Accordingly, a landowner has a legitimate interest in drilling wells for purposes of producing groundwater. Further, the mineral estate owner's implied easement of surface use may include a right to drill and utilize injection disposal wells, if reasonably necessary for the disposal of brines or other wastes from the mineral activity on the land or land unitized therewith. However, the landowner probably has the right to drill and utilize injection disposal wells too.[61] Perhaps to the extent that a landowner (or some other person claiming rights through the landowner) has a legitimate reason to conduct seismic operations or log wells, they should have just as much of a right to do those things as to build roads, drill water wells, or drill and use injection wells.

A persuasive argument can be made that, not only are past statements by courts that a mineral owner has the exclusive right to conduct geophysical operations dicta, but that the dicta is incorrect. Instead of the mineral owner having an exclusive right to conduct geophysical activities such as seismic exploration and well logging, it has the exclusive right to conduct such operations *for the purpose of evaluating land for its oil and gas potential*. The reason that the mineral owner has the exclusive right to conduct geophysical operations that are performed for the purpose of evaluating the land for its oil and gas potential is that the mineral owner has the exclusive right to explore for oil and gas. The reason some other person

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In a 1957 paper Earl Brown stated in the introduction that his paper would consider "the rights, liabilities, and remedies resulting from an unauthorized entry on and use of land for geophysical exploration in connection with the search for and discovery of oil and gas." Brown, *supra* note 59, at 57.

[61] This should hold true as long as the landowner does not interfere with the mineral owner's exercise of its rights.

could conduct geophysical operations that are performed for other purpose is that geophysical exploration is not inherently a type of oil and gas exploration. Further, such geophysical exploration need not unreasonably interfere with the mineral owner's ability to explore for and produce oil and gas.

If a court followed the reasoning outlined above, the landowner or someone claiming rights through the landowner would have the right to conduct geophysical exploration for some legitimate purpose, such as evaluating the subsurface for proposed CCS operations. Indeed, *Cowden* contains language consistent with this reasoning. In *Cowden*, the U.S. Court of Appeals for the Fifth Circuit concluded that, when a severed mineral estate exists, the surface owner cannot conduct or authorize geophysical exploration, even if the instrument created the severed mineral interest has not expressly granted the mineral estate owner an exclusive right to conduct such activities. The reason for this result is that the surface owner lacks "a legitimate interest in investigating" the land for minerals.[62]

In contrast, consider a mineral lessor. Although a lessor has no right to produce oil or gas because the exclusive right to do so has been granted to the mineral lessee, the lessor retains a right to conduct seismic exploration and authorizes third persons to do so, unless the terms of the lease grant the lessee the exclusive right to conduct geophysical exploration.[63] The reason for this result is that the lessor retains an interest—the reversionary interest—in mineral exploration.[64] This gives the lessor a legitimate interest in conducting geophysical exploration for minerals.

Arguably, although a surface owner has no legitimate interest in conducting geophysical surveys to evaluate the land for the likely presence of minerals when a severed mineral estate exists, a surface owner does have a legitimate interest in conducting geophysical surveys to evaluate the suitability of the land for a CCS project. Indeed, the surface owner's interest in investigating the suitability of the land for a CCS project is arguably a stronger interest than the interest of a mineral lessor in conducting geophysical exploration for minerals during the life of a mineral lease. After all, if a surface owner cannot conduct geophysical surveys to evaluate the suitability of the land for CCS, the surface owner's right to engage in CCS may be effectively destroyed. In contrast, a lessor could simply wait to perform geophysical exploration for minerals until the time that the lease expires, converting the lessor's reversionary interest in mineral development to a present right to develop minerals.

Grynberg, however, somewhat cuts against that reasoning. In that case, a city was searching for a site to build a wastewater reservoir and it selected a potential site.[65] But Colorado law effectively required

[62] 241 F.2d at 592.

[63] *Id.*

[64] *Id.*

[65] 739 P.2d at 232.

that a person applying for a permit to construct a reservoir had to demonstrate that the site chosen for the reservoir did not contain commercial deposits of coal. Here, there was a severed mineral estate and the mineral owner had granted a coal lease. The surface owner authorized the city to drill a well to determine whether the subsurface contained commercial deposits of coal. Relying on that permission, the city drilled the well in search of coal, but not for the purpose of considering development of the coal. Rather, the city was seeking to secure the information necessary to obtain a permit to construct a reservoir. Both the surface owner and the city presumably had a legitimate interest in securing that information and constructing a reservoir. Nevertheless, the Colorado Supreme Court held that the coal lessee had a cause of action against the city for unauthorized geophysical exploration for mineral deposits.[66]

Thus, it is conceivable that a court would conclude that a mineral owner has the exclusive right to conduct geophysical operations, without regard to the purpose that someone else might wish to do such operations. Further, even if a court ultimately ruled that a landowner and CCS operator have a right to conduct geophysical activities as long as they have a legitimate reason for doing so (that is, some purpose other than evaluating oil and gas prospects), a CCS operator would not want to spend the time and money litigating this issue.

Moreover, mineral owners consider geophysical information to be confidential and valuable. Thus, even if the landowner and CCS operator have a right to conduct geophysical operations, a mineral owner might seek some creative way to hold the landowner or CCS operator liable if they acquire geophysical information and fail to keep it confidential.[67] For all these reasons, CCS operators should consider entering agreements with mineral owners regarding geophysical operations. In such an agreement, the CCS operator should also seek an express acknowledgment from the mineral owner that the CCS operator may conduct geophysical studies for purposes of applying for a CCS operation and monitoring such operations. The CCS operator and mineral owner should consider whether they want to agree to share the costs of geophysical studies and share geophysical data, and whether they want to make promises to each other regarding keeping such information confidential to the extent reasonably possible. For example, the CCS operator might commit to submit to the regulator only as much geophysical information as reasonably necessary and to designate such information as confidential, if the regulator allows applicants to do so, to prevent disclosure of the information pursuant to public records requests or the regulator's proactive posting of information on a publicly available website.

[66] *Id.* at 239.

[67] In most jurisdictions, multiple parties can hold separate trade secret rights to the same information, provided that they each developed the information independently, but a detailed consideration of trade secret and confidentiality issues is beyond the scope of this chapter.

[3] Duration of Agreement

For a successful CCS project, a CCS operator will need rights for many years. As already noted, a prospective CCS operator will need to acquire geophysical information to evaluate the suitability of an area for CCS and to prepare a Class VI permit application. These activities will take time. Once an application is submitted, the regulator will need time to review it, and operators should not expect the sort of turnaround time they would get when applying for a permit to drill an oil and gas well. Further, once a permit is granted, some time will be necessary to construct the CCS facility, and once injections begin, the CCS operator may want to inject CO_2 for several years. Finally, after injections cease, SDWA regulations will require the CCS operator to monitor the CO_2 plume for many years—probably a few decades.[68]

Thus, the CCS operator will need to enter contracts that grant surface and subsurface rights that could last for decades, and the CCS operator may need to enter these contracts before it is certain that a Class VI permit will be granted and that a final investment decision will be made to proceed with the project.

In these circumstances, the prospective CCS operator will want the option to acquire long-term rights, without having to pay as much money as it would have to pay to actually acquire long-term rights. The landowner will want to receive some upfront, guaranteed compensation in return for granting the CCS operator an option, and will want the prospective CCS operator's rights to terminate if the CCS operator does not proceed with a CCS project that will result in the payment of additional compensation to the landowner.

One way to do this is to give the prospective CCS operator certain rights for a specified period that is a few years in length. If, at the end of that period, the operator has failed to reach some benchmark—for example, it has failed to submit a Class VI application—the agreement will terminate.

On the other hand, if the prospective CCS operator satisfies the benchmark before the end of the initial period, the operator's rights continue for another specified period of a few years. The agreement will terminate at the end of this second period unless the prospective CCS operator has reached another benchmark—perhaps having secured approval of the Class VI permit or having started construction or having commenced injections.

Finally, assuming the CCS operator satisfies the second benchmark and begins injections, the CCS operator will have a right to continue injections for a specified number of years or perhaps for as long as it continues injections without a cessation of more than six months (or some other specified period). At that point, the CCS operator's right to inject will cease, but its right to conduct the monitoring activities that are reasonably necessary or required by regulations will continue.

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[68] The default rule under federal SDWA regulations is for the monitoring obligation to last for 50 years after injections cease. 40 C.F.R. § 146.93(b).

Four publicly-available CCS pore space agreements granted by the State of Louisiana[69] and a publicly-available agreement granted by the State of Texas[70] provide potential models. For example, the lease granted by the State of Louisiana to Air Products Blue Energy LLC (Air Products) provides for a three-year Initial Term that can be extended for up to two additional years for good cause. At the end of the Initial Term, the lease terminates unless Air Products has applied for a Class VI permit. If Air Products timely applies for a permit, the lease moves into a four-year "Permit/Construction Term" that can be extended for up to four additional years for good cause. The Lease will terminate at the end of that term unless Air Products has begun the injection of CO_2. If Air Products timely begins injection of CO_2, the lease moves into an "Operational Term" that continues as long as there is not a gap of more than one year in making injections. At the end of the Operational Term, Air Products continues to have rights needed to conduct the monitoring required by law.

[4] What Should Be the Compensation Model?

A major question is the basis of the compensation that the CCS operator will pay to the landowner. Should the compensation be based on fixed fees or on fees that vary based on the income of the CCS project or a combination of both? The publicly available CCS agreements use a combination of fixed fees and income-based fees, and so do the private agreements or proposed private agreements that the author has seen. Sound arguments support this compensation model.

[a] Why the Compensation Model Should Include One or More Fixed Payments

A prospective CCS operator probably will enter contracts to secure pore space rights before it is certain that the project will be built. If the compensation model did not include one or more guaranteed payments, the contract for pore space rights might be an unenforceable *nudum pactum*. Further, it might be difficult to secure the landowner's consent to a pore space agreement if the only compensation the landowner would receive would be a share of the CCS project's income, given the uncertainty, at the time of contracting, whether injections of CO_2 will occur, what the total amount of injections will be (assuming they occur), and that the start of injections is probably years away.

An obvious solution is for the pore space agreement to require the CCS operator to pay the landowner an upfront, guaranteed payment to the landowner in return for granting the contract. This initial payment would be analogous to the bonus under an oil and gas lease, and like the bonus under an oil and gas lease the upfront payment for pore space rights will serve multiple functions. First, it will prevent the

[69] A webpage with links to each of the four agreements is available at http://www.dnr.louisiana.gov/index.cfm/page/168.

[70] The lease granted by Texas is available by public information request to the Texas General Land Office at https://s3.glo.texas.gov/glo/the-glo/public-information/requests/index.html.

agreement from being a *nudum pactum*. Second, it may give the CCS operator the status of a bona fide purchaser of property rights, and finally, it will be a guaranteed payment that helps induce the landowner to enter the agreement. Indeed, Louisiana granted four pore space agreements for potential CCS projects and Texas has granted one, and each of these provides for a significant upfront payment that could be compared to the bonus paid by an oil and gas lessee. (The amounts paid pursuant to these agreements are discussed in § 5.08, below.)

In addition, the Texas agreement requires the lessee to make a "Second Bonus Payment" and then a "Third Bonus Payment" when the CCS project reaches certain benchmarks. Further, the Texas agreement requires the lessee to pay a "royalty" on the value of the tax credits and any revenue earned by the CCS project.

In addition to the initial bonus, the Louisiana agreements each require the lessee to pay annual rentals. The first two agreements require the payment of rentals from the effective date of the agreement until injections of CO_2 begin. The next two agreements require the payment of annual rentals, starting from the time the agreement is effective, and past the time when injections begin, until the time when injections of CO_2 cease. Further, all four of the agreements granted by the State of Louisiana require payment of an injection fee that is based on the volume of injections.

In most cases, the landowner probably will want to bargain for a guaranteed, upfront amount that is payable at the time the agreement is executed or shortly afterward. The landowner may wish to bargain for additional "bonuses" that are payable when the CCS project meets certain benchmarks, as in the lease granted by the State of Texas.

The landowner may want to bargain for periodic payments that are not tied to particular benchmarks, but instead compensate the landowner merely for the fact that the agreement remains in place, much as Louisiana bargained for annual rental payments.

Further, the landowner probably will want to bargain for a fee that is tied to the volume of injections or the economic value of the tax credits and any revenue that the CCS project generates. If the fee is not set at a fraction of revenue (as is the Texas agreement), and instead is defined in terms of the volume of injections (as is the Louisiana agreement), the landowner may want to bargain (as Louisiana did) for an automatic increase in the amount the CCS operator pays for ton of CO_2 injected if the 45Q tax credit increases.

[b] Why the Compensation Model Should Include a Payment to the Landowner Based on Injection Volumes or Economic Benefit to the CCS Operator

All of the publicly available CCS pore space agreements require the CCS operator to make payments to the landowner based on CO_2 injection volumes or the CCS project's revenue. Including such a fee helps align the interest of the parties, and this brings at least two benefits.

First, it somewhat reduces the CCS operator's risk. Because the CCS operator, but not the landowner, will be incurring costs to develop the project, the CCS operator bears most of the economic risk associated with the CCS project. However, if the CCS operator agrees to pay an injection fee, it should be able to bargain to pay a lower bonus than it would have needed to pay to induce the landowner to sign a pore space agreement that did not include an injection fee. Second, because an injection fee will allow the landowner to share in revenue secured by the CCS project, the landowner has a financial motivation to hope that the CCS project will be a success. It is a truism in the oil and gas industry that landowners who are receiving a royalty or some other payment are less likely to object to the presence of oil and gas activity. The same rule should apply for CCS projects.

The landowner should also bargain for a payment based on injections (this would be analogous to the lessor's royalty under an oil and gas lease). The injection payment could be set at a specified amount per ton of CO_2 injected. If so, the landowner should consider having the "per ton" injection fee indexed to the 45Q tax credit, so that if the tax credit is increased in the future the injection fee would increase too. This is the model that the State of Louisiana has used in the CCS leases it has granted to date. Each one provides for a specified payment per ton of CO_2, but with a provision that the fee increases if the 45Q tax credit increases.

An alternative model would be to base the injection fee or royalty on the amount of economic benefits that the CCS operator obtains from the CCS project. The economic benefits could include the dollar value of 45Q tax credits and any state incentives (such as the value of the California Low Carbon Fuel Standard). Further, if third parties pay the CCS operator for injecting CO_2, that could count as an economic benefit. If the landowner gets a share of economic benefits that the CCS operator receives, the parties should consider whether this includes indirect benefits. For example, if the CCS operator owns (or an affiliated company) owns a coal-fired power plant, ethanol plant, or cement plant that would have been required to shut down due to environmental regulation in the absence of the CCS operation, should a share of the revenues from that affiliated plant count as an economic benefit in which the landowner shares. The Texas General Land Office granted a CCS lease in which Texas will receive a share of the economic benefits received by the CCS operator.

[5] Depths or Formations Where CCS Operator Will Have Storage Rights

At the time that a prospective CCS operator enters a pore space agreement, the operator typically will have a particular formation in mind that it plans to use for storage. The parties will need to decide whether the pore space agreement gives the operator the right to store CO_2 just in the particular formation, or in that formation and any deeper formations, or in any formations whatsoever. The landowner probably should seek to limit the grant of storage rights to a particular formation. The operator may want broader storage rights. If the parties' pore space agreement only grants the operator the right to store CO_2 in particular formations, the parties will need to take care in how they define the formation. This challenge will be similar to that faced in defining severances of mineral rights by depth.[71]

[6] Reasonable Diligence by CCS Operator

If a significant portion of the compensation to the landowner will be paid in the form of an injection fee or royalty, the landowner should consider bargaining for a clause that the CCS operator will use reasonable diligence in developing the CCS operation and obtaining CO_2 to inject. Such a contractual requirement would be analogous to the implied covenants that bind oil and gas lessees.

[7] "Pooling" or "Unitization"

In some cases, a CCS operation will involve injections that create a storage plume that spreads beneath multiple tracts of land. The CCS agreement should allow for such voluntary "pooling" or "unitization." Further, assuming that the pore space agreement provides for compensating the landowner based on CCS revenue or the volume of injections, the agreement should specify how the landowner's right to compensation is affected if the landowner's tract is one of multiple tracts in a "unit" for CCS.

[8] Surface Use, Surface and Subsurface Damages, Surface Restoration, and Removal of Equipment

Many oil and gas leases require the lessee to compensate the landowner for any damage to the land that the lessee causes by its operations, even if the damage was caused by activities that the lessee had the right to do and even if the damages could not have been reasonably avoided. A landowner should consider bargaining for a similar provision in a pore space agreement.

In addition, the landowner should consider bargaining for a requirement that, at the termination of injection operations, the CCS operator restore the surface to its original condition and that the operator remove any equipment and facilities not needed for ongoing monitoring. Further, the landowner should consider bargaining for a requirement that, once the CCS operator's monitoring obligations are over, that the operator restore the surface and remove any remaining equipment or facilities.

Finally, it might be appropriate for the parties' agreement to require the CCS operator to compensate the landowner if the operator physically occupies a significant area for more than a short period of time. Suppose, for example, that a "pore space agreement" also gives the CCS operator the right to use the surface. If it is clear how much of the surface the CCS operator will use and the agreement precludes the use of a greater area, then the value of the CCS operator's use of the surface can simply be factored into the price of the agreement. If, however, it is not clear how much of the surface the CCS operator might use, the parties should consider including a provision requiring that the operator compensate the landowner a specified amount per acre for the area that the CCS operator uses or physically occupies.

[71] *See, e.g.*, George, Brister & Eason, *supra* note 51.

Another circumstance in which it would be fair to give separate compensation to the landowner for use of the surface and for use of pore spaces is when the storage reservoir will encompass an area that includes numerous small tracts. In such circumstances, the CCS operator may use the subsurface pore spaces of all the tracts, but only use the surface of a few tracts. In such a circumstance, it might be fair for the owners of all tracts to receive the same per-acre compensation for the use of pore spaces, but for extra compensation to be paid to the owners of tracts whose surface is used.

[9] Miscellaneous Contract Provisions

In addition to the provisions noted above, the landowner should consider including a variety of other provisions in their pore space agreements. For example, the landowner should consider a provision requiring the CCS operator to defend and indemnify the landowner against any claims arising from the CCS operations, including the preliminary activities (such as geophysical exploration and taking corrective action on existing wells) and the ongoing monitoring that will last for years after CCS operations have ceased. The landowner should consider supplementing the contractual indemnity with a requirement that the CCS operator carry insurance that lists the landowner (and any future owner of the land) as named insureds, perhaps with a waiver of subrogation rights by the insurer. If the CCS operator is a subsidiary of a larger "parent" company, the landowner may wish to bargain for a requirement that the parent company guarantee the contractual and tort obligations that the CCS operator might owe to the landowner.

The CCS operator should consider including a clause dealing with the possibility that the land subject to the pore space agreement is later subdivided. Such a clause could address allocation of payments in the event that the land is subdivided and provide that no transfer of the landowner's interest will be binding on the operator until a specified time after delivery to the operator of a certified copy of the properly recorded instrument showing the change in ownership.

Both parties should consider whether they wish to include an arbitration provision or other dispute resolution provision in their pore space agreement.

§ 5.05 Alternatives to Agreement

This chapter focuses on agreements relating to pore space rights, but it may be possible for a CCS operator to acquire pore space rights without an agreement. At least two states—Louisiana[72] and Alabama[73]—have enacted statutes that authorize a CCS operator to acquire subsurface storage rights for CCS projects by eminent domain. In addition, at least nine other states—California,[74] Kentucky,[75]

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[72] La. Stat. Ann. § 30:1108.

[73] Ala. Code § 9-17-154.

[74] Cal. Pub. Res. Code § 71461.

[75] Ky. Rev. Stat. Ann. § 353.808.

Mississippi,[76] Montana,[77] Nebraska,[78] North Dakota,[79] Utah,[80] West Virginia,[81] and Wyoming[82]—have enacted statutes that would allow prospective CCS operators to obtain authority to use the subsurface of non-consenting landowners using procedures analogous to those used in oil and gas unitization.

However, even in these 11 states, a prospective CCS operator generally will need to be prepared to contract for the acquisition of pore space rights. In Louisiana, for example, a company must "attempt in good faith to reach an agreement as to compensation with the owner of the property" before resorting to eminent domain.[83] In Alabama, a company cannot exercise eminent domain until after it has "offered to acquire the property on the basis of its approved offer by purchase before commencing the action."[84] And, in the states that authorize a unitization-like process, the operator generally must acquire the consent of a specified fraction of the landowners before being entitled to a unitization order.[85]

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[76] Miss. Code Ann. § 53-11-9.

[77] Mont. Code Ann. § 82-11-204.

[78] Neb. Rev. Stat. § 57-1612.

[79] N.D. Cent. Code § 38-22-10.

[80] Utah Code Ann. § 40-11-10.

[81] W. Va. Code § 22-11B-19.

[82] Wyo. Stat. Ann. § 35-11-315.

[83] La. Stat. Ann. § 19:2 (procedural requirements); *see also id.* § 30:1108(C) (eminent domain for CCS).

[84] Ala. Code § 18-1A-55.

[85] *See, e.g.*, Cal. Pub. Res. Code § 71461 ("undivided three-fourths of the total interests" in proposed unit); Ky. Rev. Stat. Ann. § 353.806 (must obtain agreement from "51% of the interests"); Miss. Code Ann. § 53-11-9 (generally requiring approval by majority in interest); Mont. Code Ann. § 82-11-204 (need approval of "persons owning or holding subsurface storage rights of 60% of the storage capacity of the proposed storage area"); Neb. Rev. Stat. § 57-1610 (applicant must show it "has made a good-faith effort to obtain consent of all persons who own reservoir estates within storage reservoir," and that applicant "has obtained the consent of persons who own reservoir estates comprising at least sixty percent of the physical volume contained within the defined storage reservoir"); N.D. Cent. Code § 38-22-8 (applicant must show "consent of persons who own at least sixty percent of the storage reservoir's pore space"); Utah Code Ann. § 40-11-6 (applicant must show it "has made a good-faith effort to get the consent of all persons who own the storage reservoir's pore space" and that "no less than 70% of the reservoir's pore space have provided written consent"); W. Va. Code § 22-11B-19 (applicant for unitization must show that it "has secured

§ 5.06 With Whom Must the CCS Operator Contract—Surface Owner, Mineral Owner, or Both?

The general consensus of commentators and the few courts that have addressed the issue is that the right to authorize third parties to use the subsurface for storage belongs to the surface owner, not the mineral owner, subject to the surface owner's obligation not to unreasonably interfere with the mineral owner's right to explore and produce minerals.[86] Indeed, there are no jurisdictions where it is clear that the mineral estate owner would own pore spaces. Therefore, the CCS operator will need to contract with the surface owner for pore space rights.

However, few jurisdictions have definitively resolved this question. Further, there is some authority from at least one jurisdiction to the contrary.[87] Though that contrary authority is limited (and criticized), it lends some additional uncertainty. Therefore, if a severed mineral estate exists, it would be prudent for a prospective CCS operator to also enter a contract for pore space rights with the mineral owner.

Further, there are several reasons for a prospective CCS operator to seek to enter a contract with the owner of a severed mineral interest even if the CCS operator totally discounted the possibility that the mineral owner owned subsurface pore spaces. First, if a severed mineral servitude exists, the landowner

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written consent or agreement from the owners of at least 75 percent of the interests in the pore space of the tract or parcel for the storage facility"); Wyo. Stat. Ann. § 35-11-316 ("No order . . . authorizing the commencement of unit operations shall become effective until the plan of unitization has been signed or in writing ratified or approved by those persons who own at least eighty percent (80%) of the pore space storage capacity within the unit area.").

[86] *See, e.g.*, David E. Dismukes et al., "Integrated Carbon Capture and Storage in the Louisiana Chemical Corridor," at 118 (DE-FE0029274 Feb. 18, 2019) (stating that "probably the most-typical result across the United States" is that the surface owner, rather than the mineral owner, would own pore space rights, and that this "certainly is true in Louisiana"); Owen L. Anderson & R. Lee Gresham, "Legal and Commercial Models for Pore-Space Access and Use for Geologic CO_2 Sequestration," *Enhanced Oil Recovery: Legal Framework for Sustainable Management of Mature Oil Fields* 9-1, 9-8 to 9-9 (Rocky Mt. Min. L. Fdn. 2015); *see also* Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39, 48 (Tex. 2017) (quoting with approval a statement that "ownership of the hydrocarbons does not give the mineral owner ownership of the earth surrounding those substances"); Dick Props., LLC v. Paul H. Bowman Tr., 221 P.3d 618 (Kan. Ct. App. 2010); La. Civ. Code Ann. art. 490; S. Nat. Gas Co. v. Sutton, 406 So. 2d 669 (La. Ct. App. 1981); S. Nat. Gas Co. v. Poland, 406 So. 2d 657 (La. Ct. App. 1981); Miss. River Transmission Corp. v. Tabor, 757 F.2d 662 (5th Cir. 1985); United States v. 43.42 Acres of Land, 520 F. Supp. 1042 (W.D. La. 1982).

[87] Cent. Ky. Nat. Gas Co. v. Smallwood, 252 S.W.2d 866, 868 (Ky. 1952).

cannot grant the CCS operator any rights greater than the landowner himself possesses. Thus, the CCS operator would be bound by the implied easement that gives the mineral owner a right to use the land as reasonably necessary for the development of minerals. This creates the possibility of conflict in the event that the CCS operator has any surface facilities or subsurface pipelines on the tract that is subject to the split estate.

Further, the landowner (and hence the CCS operator) is required to avoid using the land in a way that unreasonably interferes with the mineral owner's rights to explore for and produce minerals. The existence of a CCS reservoir beneath the land will not, in itself, prohibit the mineral owner from drilling an oil and gas well through the CCS reservoir to reach deeper formations. However, regulations might require that any well drilled through the CCS storage formation meet Class VI well construction standards. This could increase the cost of drilling. Further, if a mineral owner submits an application for a permit to drill (APD) an oil and gas well through a CCS reservoir, regulators might review the permit more thoroughly than the typical application for a permit to drill an oil and gas well. This might delay approval of the application.

Second, a mineral estate owner or mineral lessee typically has the exclusive right to conduct oil and gas exploration activities. This can include an exclusive right to drill exploratory wells, run well logs, take core samples, and conduct seismic or other geophysical operations for purposes of oil and gas exploration. In preparation for submitting a Class VI application, a prospective CCS operator typically will evaluate the subsurface by drilling test wells, running well logs, perhaps by taking core samples, and by conducting seismic evaluations. The prospective CCS operator will not conduct these activities for purposes of exploring for oil and gas, but the prospective CCS operator may obtain information relevant to a tract's potential for oil and gas production. Some mineral owners have used this fact to argue a prospective CCS operator has no right to engage in such geophysical activities. Even if a mineral owner does not make that argument (or if such arguments are rejected by a court), there are issues regarding confidentiality and disclosure of geophysical information.

Third, presumably the CCS operator will not inject CO_2 into a formation that still has the potential for profitable mineral production, but if the storage formation has any potential whatsoever for mineral production—including for production using secondary recovery or enhanced oil recovery techniques, the CCS operator should obtain the mineral owner's waiver of mineral rights with respect to that formation. Moreover, if a formation is sufficiently permeable and porous for CCS operations, the formation might be a candidate for injection disposal of brine produced during oil and gas operations. Accordingly, the CCS operator should obtain the mineral owner's waiver of rights to use the storage reservoir for injection disposal.

Finally, in some cases, a CCS operator will wish to gain credits under California's Low Carbon Fuel Standard. California does not allow a CCS operator to claim such credits unless the operator has binding contracts that prohibit anyone from drilling through the CCS storage reservoir. The landowner cannot grant such a right if there is a split estate or an existing mineral lease. The CCS operator would only be able to obtain such "no-drill-through" rights by persuading the mineral owner to waive its rights to drill through the CCS reservoir.

§ 5.07 Could Someone Rely on an Oil and Gas Lease for the Authority to Conduct CCS?

Some people have raised the question whether a typical oil and gas lease might provide the authority to engage in CCS. In narrow circumstances, the answer might be "yes." Such a right could be based either on the implied easement or on an express lease clause authorizing injection disposal.

The lessee under a mineral lease generally has an implied easement to use the leased premises as reasonably necessary to develop and produce minerals subject to the lease.[88] Cases have held that the implied easement authorizes the oil and gas lessee to use the leased premises for injection disposal of produced water, if such operations are reasonably necessary to facilitate the exploration for or the production of oil and gas.[89] However, the implied easement generally would not give the lessee the right to use the leased premises for injection disposal of produced water from wells not located on the lease premises (or land unitized therewith).

The implied easement might authorize the lessee to engage in CCS operations in narrow circumstances. Suppose, for example, that the lessee produces natural gas from the leased premises or land unitized therewith. Further, suppose that CO_2 is removed from the natural gas in a gas treatment plant that only treats gas produced from the leased premises and land unitized therewith. Or, if the lease contains an adjacent-lands clause,[90] perhaps it would be alright if the treatment plant also treated gas produced from adjacent lands. Finally, assume that it is reasonably necessary to dispose of the CO_2 removed from the natural gas, rather than just to vent it. In those circumstances, the implied easement might be sufficient to justify use of the leased premises for a CCS operation that only injected CO_2 from that gas treatment plant.

But in many cases a gas treatment plant will treat gas from a broader area than just the leased premises and any lands unitized therewith, and even beyond the lands adjacent to the leased premises. In such cases, the implied easement probably would not authorize the lessee to use the leased premises for injection

[88] *See, e.g.*, Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39, 48 (Tex. 2017).

[89] *See, e.g.*, Leger v. Petroleum Eng'rs, Inc., 499 So. 2d 953 (La. Ct. App. 1986).

[90] An "adjacent lands" clause is an oil and gas lease clause that authorizes the lessee to use the leased premises to support oil and gas operations on "adjacent lands." *See* Caskey v. Kelly Oil Co., 737 So. 2d 1257, 1263 (La. 1999).

disposal of the CO_2 from the treatment plant. Courts have held that a mineral lessee could not use the leased premises for disposal of salt water produced off the lease,[91] because such disposal is not reasonably necessary for the development of minerals on the leased premises, and similar reasoning could apply to disposal of CO_2.

Further, it is common to simply vent the CO_2 removed from natural gas in a treatment plant. If regulations allow this, a strong argument exists that the implied easement would not authorize CCS.[92] And it is difficult to conceive of any circumstance in which the implied easement would authorize a CCS operation that injected CO_2 from other sources, such as power plants, ethanol refineries, methanol plants, fertilizer plants, cement plants, biofuel plants, or hydrogen plants.

If an oil and gas lease contains a clause that expressly authorizes the use of the leased premises for injection disposal, it would be necessary to examine the language of the clause, but in many cases the clause probably would only authorize injection disposal to manage wastes produced from oil and gas activity on the leased premises or land unitized therewith. Further, given that the most common use of injection disposal by oil and gas lessees is to manage produced water and perhaps waste drilling fluids, an express clause granting the lessee the right to engage in injection disposal might even limit this right to injections for disposal of produced water or produced water and drilling fluids. Thus, an express clause authorizing injection disposal will not necessarily expand the right much beyond the right that would exist under the implied easement.

Even if an oil and gas lease provides sufficient authority for the lessee to conduct CCS, a potential problem with relying on the lease as authority to conduct CCS relates to duration of the lease rights. The typical oil and gas lease will terminate when production in paying quantities ceases, unless a savings clause in the lease keeps the lease alive. But a CCS operator's duty under SDWA regulations to monitor CCS operations typically will continue for many years after injections of CO_2 cease. Thus, the lessee's rights under the oil and gas lease could terminate years before the lessee's obligations under SDWA regulations end. If the lessee needs to enter the leased premises to conduct seismic operations, make CO_2 concentration readings, or access a monitoring well, the lessee's rights under the lease might not be adequate.

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[91] TDC Eng'g, Inc. v. Dunlap, 686 S.W.2d 346 (Tex. App.—Eastland 1985); *see also* Slaaten v. Cliff's Drilling Co., 748 F.2d 1275 (N.D. 1984).

[92] Joel R. Sminchak, Sanjay Mawalkar & Neeraj Gupta, "Large CO_2 Storage Volumes Result in Net Negative Emissions for Greenhouse Gas Life Cycle Analysis Based on Records from 22 Years of CO_2-Enhanced Oil Recovery Operations," 34 *Energy Fuels* 3566 (2020).

Finally, if a company does conduct CCS operations pursuant to an oil and gas lease, an issue will arise as to whether the lessor is entitled to share, under one theory or another, in the economic benefits derived from the 45Q tax credits.[93]

§ 5.08 Determining Market Value?

Because CCS agreements are relatively new, there is limited information available regarding the market value of pore space rights. One could look by analogy to the prices paid when companies have acquired pore space easements for natural gas by eminent domain. In some of those cases, the storage operator paid a flat fee of $50 per acre.[94] However, in the publicly available CCS pore space agreements are leases in which the prospective CCS operators made an upfront payment comparable to or higher than paid in those easement cases, plus large additional payments.

For example, the State of Louisiana granted a lease to Air Products for pore space rights for a CCS project in October 2021.[95] Air Products paid an upfront fee (somewhat analogous to an oil and gas lease bonus) of $50 per acre,[96] plus Air Products agreed to pay $50 per acre annual rental fees until it begins injecting CO_2.[97] In addition, Air Products committed to paying an injection fee that was initially set at $1.50 per metric ton of CO_2 injected, but the pore space lease provided that the injection fee would increase by

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[93] Frey v. Amoco Prod. Co., 603 So. 2d 166, 174 (La. 1992) (holding that lessee had to pay royalty on take-or-pay settlement payment because any "economic benefit accruing from the leased land, generated solely by virtue of the lease, and which [a royalty obligation] is not expressly negated, is to be shared between the lessor and lessee in the fractional division contemplated by the lease" (citation omitted)).

[94] *See, e.g.*, Dominion Transmission, Inc. v. An Exclusive Easement to Use the Oriskany Formation, No. 6:16-cv-06693, 2018 WL 692103 (W.D.N.Y. Feb. 2, 2018); Hardy Storage Co. v. An Easement to Construct, Operate & Maintain 12-Inch & 20-Inch Gas Transmission Pipelines, Nos. 2:06-cv-00007, 2:07-cv-00005, 2009 WL 900157 (N.D. W. Va. Mar. 31, 2009). Hardy Storage Co. v. Property Interests Necessary to Conduct Gas Storage Operations, No. 2:07-cv-00005, 2009 WL 689054 (N.D. W. Va. Mar. 9, 2009).

The author thanks Paul K. Stockman of Kazmarek Mowrey Cloud Laseter LLP for bringing these cases to the author's attention.

[95] The Air Products agreement is available at https://www.dnr.louisiana.gov/assets/OMR/media/forms_pubs/CS01A.pdf.

[96] Louisiana's Air Products agreement required an upfront bonus of $6,122,750 for an agreement covering over 122,400 acres. Air Products agreement, art. 4.1 & Exhibits B, C, D.

[97] *Id.* at art. 4.2.

9% of any increase in the 45Q tax credit.[98] Thus, because the 45Q tax credit has increased from $50 to $85 per ton, the injection fee should now be $4.65 per ton. Further, to protect the state against the possibility that Air Products will inject very little volume, the injection fee will be calculated based on a minimum injection volume (that is based on multiple factors) in the event that actual injection rates fall below that level.[99]

In October 2021, the State of Louisiana also granted a pore space lease to Capio Sequestration, LLC.[100] The agreement provided for an initial payment of about $34.10 per acre,[101] plus annual rentals of $50 per acre until injections begin,[102] then an injection fee. The injection fee was initially set at $1.60 per ton, with a provision that the injection fee will increase by 5% of any increase in the 45Q tax credit.[103] With the recent increase in the 45Q tax credit, the injection fee should now be $3.35 per ton. The agreement specifies that, if injection volumes fall below a certain level, the injection fee will be calculated based on a minimum volume specified in the agreement.[104]

In an agreement granted more recently by the State of Louisiana, in September 2022, Venture Global CCS Plaquemines, LLC (VG Plaquemines)[105] agreed to make an initial payment of $100 per acre,[106] plus a rental fee of $50 per acre from the date of the lease until injections cease (thus, the rentals continue after injections begin, unlike in the earlier agreements),[107] and an injection fee of $6.50 per ton (this will increase if the 45Q tax credit is increased above $85 per ton), payable on a minimum of 250,000 tons per year after injections begin.[108]

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[98] *Id.* at art. 4.3.

[99] *Id.*

[100] The Capio agreement is available at https://www.dnr.louisiana.gov/assets/OMR/media/forms_pubs/CS02A.pdf.

[101] Capio agreement, art. 4.1. Louisiana's Capio agreement called for upfront bonus payments totaling $1,518,000 for an agreement covering over 44,000 acres ($38.76 per acre for one area and $21.19 per acre for another area). *Id.*

[102] Capio agreement, art. 4.2.

[103] *Id.* at art. 4.3.

[104] *Id.*

[105] The VG Plaquemines agreement is available at https://www.dnr.louisiana.gov/assets/OMR/media/forms_pubs/CS003.pdf.

[106] VG Plaquemines agreement, art. 4.1.

[107] *Id.* at art. 4.2.

[108] *Id.* at art. 4.3.

Finally, and also in September 2022, the State of Louisiana granted a pore space lease to Venture Global Cameron, LLC (VG Cameron)[109] in return for an upfront payment of \$171 per acre,[110] annual rentals of \$50 per acre (from the effective date of the lease until injections cease),[111] and an injection fee of \$6.50 per ton, which will increase if the 45Q tax credit is increased again, payable on a minimum of 750,000 tons per year.[112]

The State of Texas, through its General Land Office, granted a pore space lease to Bayou Bend CCS LLC (a subsidiary of Talos Energy Inc.) for an area in the Gulf of Mexico. The lease requires the lessee to make an "Initial Bonus Payment" of \$4.5 million within five days of executing the agreement.[113] The lease covers a little over 40,200 acres, so the Initial Bonus is about \$110 per acre. Further, the lease requires the lessee to make a "Second Bonus Payment" of \$4.5 million whenever the CCS operator has secured a contract or contracts committing at least four million metric tons per year of CO_2 to the project for injection,[114] and a "Third Bonus Payment" of \$4.5 million whenever the operator begins injections.[115] Further, the lease requires the lessee to pay a "royalty" equal to 3% of Facility Proceeds during an initial period and 6% later, with "Facility Proceeds" defined to include tax credits and any income. Thus, during the initial period, if the \$85 per ton 45Q was the only economic benefit, the royalty would be \$2.55 per ton, and this would rise to \$5.10 per ton later.[116]

§ 5.09 Conclusion

Policymakers at the state, federal, and international level support the use of CCS as a tool to combat climate change. Further, there is growing interest in CCS projects, and this interest is likely to continue increasing given the recent increase in the federal 45Q tax credit for CCS projects.

Prospective CCS operators will need to secure subsurface pore space rights from the landowners who own the land beneath which a plume of CO_2 injected into a storage reservoir will spread. The operators will need to obtain the right to conduct geophysical activities necessary to collect the information needed

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[109] The VG Cameron agreement is available at https://www.dnr.louisiana.gov/assets/OMR/media/forms_pubs/CS004.pdf.

[110] VG Cameron agreement, art. 4.

[111] *Id.* at art. 4.2.

[112] *Id.* at art. 4.3.

[113] Bayou Bend agreement, art. 3.01(a).

[114] *Id.* at arts. 3.01(b), 3.02(f).

[115] *Id.* at arts. 3.01(c), 3.02(m).

[116] The Bayou Bend agreement is available from the Texas General Land Office by public records request.

to apply for a Class VI injection well permit under the SDWA, and if the project is approved, the operator will need to secure the rights to inject CO_2 that will migrate into subsurface pore spaces beneath land owned by other persons, and the right to engage in activities to monitor the spread of the CO_2 plume during the period when injections are being made and for decades afterward.

These pore space agreements should have a term (duration) that can last for decades in the event that the prospective CCS operator timely builds a CCS project and begins injections. But the agreements should terminate unless the prospective CCS operator satisfies specified project benchmarks and begins injection of CO_2 within a specified time. Pore space agreements should provide for a guaranteed, upfront payment to landowners that is similar to the bonus paid for an oil and gas lease. In addition, pore space agreements should provide for compensation to be paid to the landowner based on either the volume of CO_2 injected or the amount of tax credits and revenue earned by the CCS project.

CARBON DIOXIDE TRANSPORTATION AND STORAGE LEASE

This Carbon Dioxide Transportation and Storage Lease (this "**Lease**") is granted by virtue of the authority granted in Chapters 33 and 51 Tex. Nat. Res. Code, 31 TAC Chapter 13 (Land Resources) et seq., Tex. Health and Safety Code Sec. 382.501 et seq., and all other applicable statutes and rules, as the same may be amended from time to time, is subject to all applicable State regulations promulgated from time to time, and is dated to be effective as of April 1, 2022 (the "**Effective Date**"), by and between the State of Texas, acting by and through the Commissioner of the Texas General Land Office, on behalf of the Permanent School Fund of the State of Texas, with its primary address at 1700 North Congress Avenue, Austin, Texas 78701 ("**Lessor**"), and Bayou Bend CCS LLC with its primary address at 333 Clay Street, Suite 3300, Houston, Texas 77002 ("**Lessee**"). Lessor and Lessee are sometimes individually referred to in this Lease as a "**Party**" and collectively as the "**Parties.**"

RECITALS

A. Pursuant to Texas Natural Resources Code, Ch. 33, the Texas School Land Board (the "**SLB**") is authorized to lease submerged land for any purpose that is in the best interests of the State, subject to the applicable notice requirements of that chapter.

B. Texas Health & Safety Code, Sections 382.501 et seq. allow the SLB to lease Permanent School Fund ("**PSF**") land for the construction of any necessary infrastructure for the transportation and offshore deep subsurface geologic storage of anthropogenic carbon dioxide.

C. On April 7, 2021, the SLB issued RFP No. 21-SLB-1-ST (the "**RFP**") and provided the appropriate public notice of the opportunity to lease PSF land for offshore storage of anthropogenic carbon dioxide in compliance with applicable law and as set out in the RFP.

D. On August 24, 2021, following receipt and review of responses to the RFP, the SLB approved a staff recommendation to proceed with lease negotiations with Lessee consistent with the terms of the RFP and with the SLB's approval of the recommendation.

E. Lessee responded to the RFP and applied to become the "Lessee" hereunder, and the SLB, finding at its meeting held on March 1, 2022, that the award of this Lease to Lessee would be in the best interests of the State, approved this Lease.

AGREEMENT

Now, therefore, in consideration of the premises, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE I. GRANT

1.01 <u>Lease of Property</u>. In consideration of the mutual covenants contained herein and other good and valuable consideration, and subject to all of the terms and conditions of this Lease and for the term of this Lease, Lessor hereby grants, leases and lets unto Lessee the Permanent School Fund lands described in **<u>Exhibit A</u>** attached hereto (the "**Leased Property**") for the exclusive right to geologically store anthropogenic carbon dioxide ("**CO2**") in a reservoir(s) and pore space in the Miocene Formation (as such term is defined under the most expansive definition required to ensure certification or classification of the CO2 sequestration as permanent under any protocols, standards, regulations or laws relevant to Lessee and its storage activities conducted pursuant to this Lease, the "**Storage Unit**"), together with the exclusive right to drill and to construct, maintain, and operate pipelines, flowlines, wells, fixtures, machinery, and any other equipment Lessee deems necessary for the purposes herein and in connection with such geologic storage (such Storage Unit, together with associated pipelines, wells, fixtures, machinery, and equipment, called the "**Facility**" herein, and the permitting, construction, and operation of the Facility, sometimes called the "**Project**" herein). The intent of the Parties is that all equipment, pipe, supports, facilities, meters, systems and ancillary items placed or maintained by Lessee on the "Property" (defined below) shall be considered part of the Facility and shall be owned and controlled by Lessee except as provided for in Section 9.03 and Section 4.01 of this Lease. If Lessee proposes to construct or cause the construction of any infrastructure required to provide electricity or other power to an injection well or other component of the Facility (other than by running power lines to the Facility from an existing onshore connection to the power grid), Lessee will notify Lessor prior to such construction and include in such notification the timing, size, location, and pathways of power generation and distribution.

1.02 Surface Access and Easements. In addition to the lease of the Leased Property to Lessee, Lessor hereby agrees that it will grant to Lessee the necessary easements, ingress and egress rights, rights-of-way, and surface locations over, across, and under certain tracts of land owned by the Permanent School Fund (the "**Easement Tracts**"), for the construction, installation, maintenance, and operation of pipelines, meters, and related equipment for the transportation of CO2 from its source to the Leased Property and the measurement thereof. The Parties hereby agree to amend **Exhibit A** to this Lease and the Memorandum to reflect any Easement Tracts conveyed by Lessor to Lessee. The Leased Property and the Easement Tracts are, collectively, the "**Property**".

1.03 Permits. As more fully set forth in Section 2.02 (Development Term) below, Lessee may seek and obtain such federal, state, or local permits, rights, and approvals as are necessary for the Project and the Facility. Upon expiration or earlier termination of this Lease, to the extent permitted by law, Lessor and Lessee shall cooperate to transfer any such permit rights to Lessor. Lessee's obligation to transfer permits to Lessor shall survive the termination of this Lease. Lessee's obligations under this Section 1.03 shall not require Lessee to incur any unreasonable expenses or costs. Subject to the provisions of Sections 2.05 and 4.01(a), from and after the effective date of the transfer of such permits to Lessor, Lessor shall (i) assume responsibility for complying with said permits and all applicable regulatory requirements and (ii) release Lessee from all claims, losses, and other liabilities for actions or non-compliance arising under the permits that (a) are the result of acts or omissions of Lessee that are actually known to and expressly accepted by Lessor, (b) could have been known by Lessor in the exercise of reasonable due diligence, or (c) are the result of acts or omissions occurring after the date of such transfer and that relate to compliance or noncompliance with all federal, state, or local permits, rights and approvals as are necessary for the Project and the Facility.

1.04 Carbon Credits. Except as provided in Section 4.01(b) below, Lessor will not claim ownership of any Carbon Credits (defined below) attributable to CO2 captured and stored in the Storage Unit. Subject to the terms of this Lease regarding control and monetization of stored CO2 in the Storage Unit, Lessor and Lessee agree to use reasonable efforts to assist each other, at the cost of the requesting party, in efforts to obtain any such Carbon Credits (defined below) that are attributable to the Facility, including Carbon Credits earned or utilized by emitters, direct or indirect members of an emitter, Lessor or Lessee, tax equity investors or others.

1.05 Reserved Rights.

(a) Subject to Section 1.05(b), Lessor expressly reserves the following from the rights in the Property and in the Easement Tracts otherwise granted to Lessee in this Lease (the "**Reserved Rights**"):

(i) **Mineral Leases**. The right to retain existing leases or execute and enter into new leases for the exploration, development, production, treatment, marketing, sale and transportation of oil, gas, and other minerals to third persons, and to grant to such mineral lessees the right to use the surface and subsurface of the Property for ancillary purposes in a manner that does not materially or unreasonably interfere with the rights granted to Lessee in this Lease, with Lessee's operations hereunder, or Lessee's ability to obtain Carbon Credits attributable to the Facility. Lessee agrees and acknowledges that this Lease does not prohibit a lessee or operator of a state lease or operating agreement granted for the development and production of minerals, oil, or gas on the Property from conducting hydrocarbon drilling or extraction activities (1) above the ceiling of the Storage Unit, or (2) beneath the base of Storage Unit; provided, however, during the Term, under no circumstance shall any well bore be drilled through the Storage Unit, nor shall the Storage Unit be exposed to communication with any well bore (the "**Drill-Through Restriction**"). During the Operations Term, Lessor may request modifications to the Drill-Through Restrictions by providing no less than ten (10) business days' notice to Lessee. Promptly thereafter, Lessor and Lessee shall (A) meet in good faith to discuss such modifications and their potential impact on (1) the integrity of the Storage Unit, (2) the then-current location of the Plume, (3) the forecasted migration of the Plume in the Storage Unit, and (B) enter into a separate agreement as to the modifications to the Drill-Through Restrictions to the extent any such modifications are mutually agreeable to the Parties. In the event Lessee is unable to obtain, in the ordinary course and without undue delay, hardship, or expense, a Class VI Permit from the applicable governmental agency, and such agency indicates that the terms of this Lease are the reason for such denial, then the Parties shall amend, in good faith, the terms of this Lease objected to by the applicable governmental agency. Lessor (i) will not authorize any lessee or operator of a state oil and gas lease or operating agreement to conduct, and shall contractually prohibit and ensure that any such oil and gas leases or operating agreement prohibits, any activities that might reasonably be anticipated to cause the escape or migration of CO_2 from the Storage Unit (any such occurrence, a "**Leak Event**"), and (ii) acknowledges that such prohibition is necessary given the applicable laws and regulations including the rules and regulations required for a Class VI Permit, as hereafter defined. If following the reasonable operation of the Storage Unit, Lessee discovers that the Plume has extended beyond the boundary of the Leased Property, Lessee shall notify Lessor of such occurrence and Lessor shall thereafter exercise its reserved rights hereunder in a way reasonably intended to avoid the occurrence of a Leak Event with respect to the area located outside of the boundary of the Leased Property. Lessor agrees and acknowledges that Lessee shall have the right to drill through, but not commercially produce any oil, gas, mineral, water, or any other substance from, any geologic formations, reservoirs, saline aquifers and/or pore spaces in the lands comprising the Property down to the base of the Storage Unit, subject to the rules for a Class VI well and other applicable regulatory requirements. Lessor acknowledges the importance of Carbon Credits to this Lease and will undertake reasonable steps to enforce the obligations of its mineral lessees under their respective State leases. Lessee shall immediately notify Lessor in writing if Lessee receives any notice from the IRS that an action or omission could lead, or has led, to Recaptured Amounts. Following all closure and monitoring requirements in accordance with Section 2.05 and Section 4.01(a), Lessor shall have the unrestricted right to drill through the Storage Unit.

(ii) **Other Uses of the Property.** Except with respect to mineral rights which are covered by Section 1.05(a)(i) above, the right to enter into, or to grant easements or other access rights to third parties to enter into, the Property and/or the Easement Tracts for any use, to conduct any activity, or to construct, maintain, and operate any facility or infrastructure, provided that such easements and access rights do not materially or unreasonably interfere with (A) the rights granted to Lessee in this Lease, (B) Lessee's operations hereunder, or (C) subject to Art. III, below, Lessee's ability to obtain Carbon Credits attributable to the Facility.

(b) Lessor shall give advance written notice to Lessee prior to (i) entering into any lease on some or all of the Property for the exploration or production of oil, gas, and other minerals or (ii) granting easements or other access rights to third parties to enter into the Leased Property and/or the Easement Tracts for any use, to conduct any activity, or to construct, maintain, and operate any facility or infrastructure. Lessor shall not enter into any such lease or grant any such easement or access rights to third parties for any activity that might reasonably be anticipated to cause a Leak Event or would materially or unreasonably interfere with the rights granted to Lessee in this Lease, with Lessee's operations hereunder, or Lessee's ability to obtain Carbon Credits attributable to the Facility. Notwithstanding the foregoing, and for the avoidance of doubt and to provide additional clarity, the Parties agree that (1) hydrocarbon drilling or extraction by any lessee or operator of a state oil and gas lease or operating agreement granted for the development and production of minerals that exposes the Storage Unit to communication with the well bore, or which might reasonably be anticipated to cause a Leak Event is expressly prohibited, and (2) as a condition of any future state lease on any part of the Property or the grant of any lease, easement or access rights to the Property, Lessor shall require the lessee or holder of such lease, easement or access rights to expressly indemnify and defend Lessee for all claims for damages or losses (including losses attributable to Carbon Credits previously realized by Lessee which are recaptured or otherwise disallowed) that Lessee may suffer or incur as a result of such party's activities, including such losses or damages, including legal fees, that result from any Leak Event. Such indemnity shall be (A) set forth in a separate written agreement between Lessee and the lessee or holder of such lease, easement or access right, and (B) be backed by adequate financial security (i.e posting of bonds, letters of credit, or other financial assurance) in favor of Lessee and its designees, in each case of (A) and (B), in a form reasonably acceptable to Lessee.

ARTICLE II. TERM

2.01 **Term**. Subject to all of the terms and conditions of this Lease, the "**Term**" (herein so called) of this Lease shall consist, collectively, of each of the Development Term, Construction Term, and Operations Term (as those terms are defined below), as well as the closure and monitoring period following the Operations Term, as and to the extent that each such portion of the Term is in effect pursuant to the terms of this Lease.

2.02 Development Term.

(a) **Due Diligence**. Subject to earlier expiration because of the commencement of the Construction Term, the first three (3) years following the Effective Date of this Lease shall be the "**Development Term**", as extended by the Development Term Extension Period pursuant to Section 2.02(f). During the Development Term, and at no cost or expense to Lessor, Lessee may conduct its due diligence and take any action that Lessee believes is reasonably necessary to determine whether the Property is suitable for the Project, including, without limitation, conducting engineering studies, economic studies, seismic or geological studies, applying for permits, marketing, and drilling test wells; provided, however, that, during the Development Term, (x) Lessee shall consult with Lessor regarding the location and spacing of test wells prior to drilling, and (y) except to the extent in connection with the drilling of a test well, Lessee may not make any material physical changes to the Property that would materially or unreasonably (i) interfere with Lessor's Reserved Rights, or (ii) damage the storage capacity of the Property, in each case, without the prior written approval of Lessor, which approval may be given or not in Lessor's sole discretion; and provided further that Lessee may not, without the prior written approval of Lessor, apply for a permit the issuance of which would preclude use of the Property by Lessor or its lessees for any purpose that is reserved to Lessor pursuant to Section 1.04 of this Lease.

(b) Permits. Lessee shall be responsible for applying for, obtaining, and thereafter maintaining, any and all necessary permits for construction and operation of the Facility, including, without limitation and to the extent required by applicable law or regulation, a Class VI UIC well permit as defined in 75 Federal Register 77229 ("**Class VI Permit**"); provided, however, Lessor shall use reasonable efforts (but without the obligation to incur any out-of-pocket costs, expenses, or the obligation to undertake any liability or other obligations to or by Lessor) to assist Lessee to the extent necessary to obtain any and all necessary permits for the Project and the construction and operation of the Facility, including a Class VI Permit or other applicable underground injection control (UIC) permit. Likewise, until such time that ownership of the CO2 is transferred to Lessor pursuant to Section 4.01(a), Lessee shall be responsible for ongoing compliance with all federal, State, and local laws, ordinances, and regulations that are or become applicable to the Project and/or the Facility. Lessee must be able to demonstrate to Lessor, to Lessor's reasonable satisfaction, that all such permits have been obtained or have been applied for and are being diligently pursued for approval, and that Lessee is in material compliance with all such applicable laws, ordinances, and regulations at the time that Lessee proposes to begin the Construction Term under this Lease. With regard to its obligations under this paragraph, "Lessee" includes the named Lessee as well as its agents and contractors.

(c) Termination by Lessee. Lessee may terminate this Lease at any time during the Development Term upon thirty (30) days' prior written notice thereof delivered to Lessor. Lessor acknowledges and agrees that Lessee has provided to Lessor sufficient and independent consideration for such option to terminate. Upon such termination by Lessee, this Lease and the obligations of the Parties under it, shall terminate, except for any obligation of Lessor or Lessee that expressly survives termination hereof pursuant to the other terms and conditions of this Lease, including, without limitation, any such surviving obligations pertaining to indemnification of Lessor, removal of equipment, and remediation, and any accrued obligation to make payments provided hereunder shall survive the termination of this Lease. Following such termination, Lessee shall retain all necessary and incidental rights to access the Property and the Facility to undertake all obligations required under this Lease or applicable law.

(d) No Warranties. Lessor expressly makes no representations or warranties whatsoever that Lessee or Lessee's proposed providers of CO2 for storage will be able to satisfy any requirements of Sec. 45Q of the Internal Revenue Code. Regardless of the availability of any such tax credit, Lessee's payment obligations under Section 3.01 of this Lease shall continue hereunder until such time as such payment obligations are no longer due and payable hereunder pursuant to the other terms and conditions of this Lease.

(e) Progress Report. Beginning with the first such report due on the six-month anniversary of the Effective Date, and every six months thereafter during the Development Term, Lessee shall prepare and submit to Lessor a "**Development Term Progress Report**". Each Development Term Progress Report shall provide Lessee with a general update of how development activities are progressing, including with regard to permitting activities, possible sources of CO2 for storage, and the results of studies regarding engineering for and upcoming construction of the Facility; provided, however, Lessor shall maintain the Development Term Progress Reports strictly confidential, and shall not disclose all or any portion of the Development Term Progress Reports to any third party without the prior written consent of Lessee, which consent may be withheld in Lessee's sole discretion (provided that all of Lessor's foregoing obligations are subject to the Texas Open Records Act and to any relevant order of a court of competent jurisdiction). Notwithstanding the foregoing provision regarding the qualified confidentiality of the Development Term Progress Reports, Lessor may analyze those reports, draw conclusions from them, and develop General Land Office best practices standards and requirements that may be shared by Lessor with the general public, including future CO2 storage space lessees, even if those General Land Office-developed "best practices" standards and requirements are, ultimately, identical or substantially similar to Lessee's reported development activities. Subject to the notice and cure provisions of this Lease, Lessee's failure to provide Lessor with a Development Term Progress Report shall be a Default under this Lease.

(f) **Deadline to Apply for and Obtain Class VI Permit; Extension of Development Term**. Notwithstanding any other provision of this Lease to the contrary, if Lessee has not applied for a Class VI Permit or other applicable UIC permit within thirty-six (36) months after the Effective Date, , then Lessor may terminate this Lease upon thirty (30) days written notice thereof delivered to Lessee; provided, however, that if Lessee has not obtained the necessary UIC permit for the Facility by the expiration of the Development Term but, at that time, is diligently pursuing such permit and is otherwise not in Default of this Lease, then upon delivery of (A) written notice, and (B) extension consideration of four hundred and fifty thousand dollars ($450,000) to Lessor on or before the date that is thirty (30) days prior to such Development Term expiration, Lessee may elect to extend the Development Term for a period of twelve (12) months (a "**Development Term Extension Period**"); provided, however, and subject to the foregoing notice requirements, the Development Term may only be extended once pursuant to this Section 2.02(f).

2.03 **Construction Term.**

(a) **Duration**. Subject to the other provisions of this Lease, the "**Construction Term**" shall (a) begin on the earlier of (i) the expiration of the Development Term (if Lessor or Lessee have not earlier terminated this Lease as provided above), or (ii) the date on which Lessee gives written notice to Lessor of Lessee's intent to proceed with construction of the Facility (regardless if Lessee has actually obtained the Class VI Permit at such time), and shall (b) end on the earlier of (1) the date that the Facility is complete and fully permitted such that Lessee may begin receiving and storing CO2 in the Storage Unit pursuant to its permits and this Lease (the "**Complete Date**"), or (2) the expiration of three (3) years after the commencement of the Construction Term (the "**Long Stop Date**"), as such Long Stop Date may be extended pursuant to Section 2.03(b). Notwithstanding any other provision of this Lease to the contrary, if Lessee has not obtained a Class VI Permit by the sixth anniversary of the Effective Date, then Lessor may terminate this Lease upon thirty (30) days written notice thereof delivered to Lessee; provided, however, that, Lessor agrees that it will weigh, among other factors, (i) Lessee's diligence in pursuing approval of a Class VI Permit or other applicable UIC permit, (ii) any delays in the approval process that were not reasonably foreseeable, and (iii) the exigencies of permitting an offshore sequestration site which is novel in the continental United States (the "**Offshore Exigencies**"), in making its decision whether or not to elect to terminate this Lease.

(b) **Termination by Lessor**. If the Complete Date has not occurred on or before the Long Stop Date, then Lessor may terminate this Lease upon thirty (30) days written notice thereof delivered to Lessee; provided, however, that if at the time of such Long Stop Date (or Construction Term Extension Period, as applicable) Lessee is diligently pursuing completion of the Facility and is otherwise not in Default of this Lease, then upon delivery of (A) written notice, and (B) extension consideration of four hundred and fifty thousand dollars ($450,000) per extension period to Lessor on or before the date that is thirty (30) days prior to such Construction Term (or Construction Term Extension Period, as applicable) expiration, Lessee may elect to extend the Construction Term (or Construction Term Extension Period, as applicable) for a period of twelve (12) months (each a "**Construction Term Extension Period**"); provided, further, however, and subject to the foregoing notice requirements, the Construction Term may only be extended pursuant to this Section 2.03(b), in the aggregate, for an additional twenty-four (24) months, (or two (2) Construction Term Extension Periods). If Lessee has not achieved the Complete Date prior to the expiration of the Construction Term Extension Period(s), then Lessor may elect to terminate this Lease upon thirty (30) days written notice thereof delivered to Lessee. Prior to electing to terminate this Lease in accordance with the prior sentence, Lessor agrees that it will (i) weigh, among other factors, Lessee's diligence in pursuing completion of the Facility and the Offshore Exigencies in making its decision whether or not to elect to terminate this Lease, and (ii) consider, in good faith, whether granting Lessee an additional Construction Term Extension Period in exchange for reasonable additional extension consideration is warranted. Following such termination, Lessee shall retain all necessary and incidental rights to access the Property and the Facility to undertake all obligations required under this Lease or applicable law.

(c) **Lessee Solely Responsible**. Lessee shall be solely responsible for designing, manufacturing, procuring, permitting, fabricating, constructing, erecting, installing, operating, maintaining and paying for the Facility.

(d) **Diligent Pursuit**. During the Construction Term, at no cost or expense to Lessor, Lessee shall construct and complete the Facility. If the Complete Date has not occurred on or before the Long Stop Date, as extended pursuant to Section 2.03(b), and if Lessor has not exercised its right to terminate this Lease pursuant to Section 2.03(b), Lessee shall, nevertheless, continue diligently working during the Operations Term (defined below) to construct the Facility, achieve the Complete Date, and begin operating the Project.

(e) **Construction Plans**. Lessee acknowledges that, as the owner of the Property, Lessor has a reasonable and legitimate interest in remaining informed about the location, design, construction, and operation of the Facility. Lessee shall (i) maintain and retain, and provide Lessor with reasonable access to, an online repository for the documents prepared and submitted for the approval and maintenance of the Class VI Permit or other applicable UIC permit for the Facility, as well as all plans and documents prepared for obtaining an approved Monitoring, Reporting, and Verification Plan ("**MRV**") from the relevant governmental authority, (ii) provide Lessor with copies of all relevant permits, plans, schematics, as-builts, and all other materials reasonably requested by Lessor that pertain to the design, construction, location, and operation of the Facility (collectively, the "**Plans**"); provided, however, Lessor shall maintain the Plans strictly confidential, and shall not disclose all or any portion of the Plans to any third party without the prior written consent of Lessee, which consent may be withheld in Lessee's sole discretion (provided that all of Lessor's foregoing obligations, including obtaining Lessee's prior written consent for disclosure, are subject to (A) the provisions of Section 10.16, and (B) the Texas Open Records Act and to any relevant order of a court of competent jurisdiction). Notwithstanding the foregoing, however, Lessee shall be solely responsible and liable for the permitting, design, and construction of the Facility, and the receipt by Lessor of the Plans and any commentary by Lessor to Lessee regarding the Plans shall not be construed in any way as the undertaking by Lessor of any professional or legal responsibility whatsoever for either the completeness or adequacy of the Plans or the Facility as it is actually constructed and operated by or on behalf of Lessee. Lessee shall be solely responsible for all performing and/or obtaining all testing, inspections, and approvals necessary for Lessee to achieve the Complete Date and to begin operating the Facility as intended by this Lease.

(f) **Minimum Construction Requirements**. All work done by or on behalf of Lessee with regard to the Project shall be (i) pursued diligently and timely, and performed in a good and workmanlike manner, and (ii) undertaken in material compliance with (A) at a minimum, the requirements of 40 CFR Sec. 146.86—93, if applicable, regarding construction, testing, operating, monitoring, reporting and closure (which shall also apply, as appropriate, to the Operations Term), and (B) all other applicable laws and regulations, and as a reasonably prudent operator, including as set out in the approved UIC permit and MRV.

2.04 Operations Term

(a) Duration. The "**Operations Term**" shall begin immediately upon the expiration of the Construction Term (the "**Operations Commencement Date**"), and shall end upon the earlier of (i) the date that is thirty (30) years after the Operations Commencement Date, (ii) the Maximum Capacity Date, or (iii) as otherwise terminated pursuant to the terms hereof.

(b) Lessee's General Obligations. During the Operations Term, Lessee shall (i) maintain all permits necessary under applicable law for the initial and continued operation of the Facility, including, without limitation, a Class VI Permit or other applicable UIC permit, (ii) obtain, operate, maintain, repair, and replace all pipelines, meters, equipment, and machinery as necessary for the safe and effective operation of the Facility, (iii) satisfy all requirements on Lessee under this Lease, including, without limitation, with regard to metering and reporting, (iv) pay all amounts owing to Lessor pursuant to the terms of this Lease, and (v) when it becomes appropriate, and with sufficient time prior to the expiration or earlier termination of this Lease, prepare for and, as applicable, perform all actions and install all equipment reasonably necessary for the post-injection period, including for closure of the Facility and post-closure monitoring, in each case, as required by applicable laws and regulations.

(c) Limit of Facility. At such time as the Storage Unit has reached the limit of its capacity to store injected CO_2 (the "**Maximum Capacity Date**"), Lessee shall cease transporting CO_2 to the Facility for injection, and shall otherwise cease injecting CO_2 into the Storage Unit. With the cessation of injection of CO_2 into the Storage Unit as the result of reaching the maximum technically accessible storage volume, the Operations Term shall terminate.

(d) Removal of Property. Subject to Lessor's remedies in the event of a Default hereunder by Lessee, Lessee shall have the right, at any time during the term of this Lease, to remove any personal property, improvements, equipment and fixtures placed by Lessee on the Property, provided, however, that no such removal may materially adversely affect the operation or safety of the Project.

(e) Low Injection Period. During the Operations Terms, if Lessee fails to inject at least the Standard Annual Volume into the Storage Unit for three (3) consecutive Lease Years (such time period to be extended, day-for-day, during the pendency of any Force Majeure event affecting Lessee) then either Party shall have the right to terminate the Operations Term by delivering written notice to the other Party no less than sixty (60) days following the commencement of the immediately subsequent Lease Year.

2.05 Closure and Monitoring. Following the expiration or earlier termination of the Operations Term, the Term of this Lease shall remain in effect, and Lessee shall remain responsible for closure of the Facility and the establishment of monitoring equipment and protocols, and for taking any other action, all in compliance with applicable regulations and generally accepted industry standards to ensure the continued, safe storage of CO_2 in the Storage Unit as required by the terms of this Lease. To the extent that Lessee's compliance with its closure and monitoring obligations hereunder (including under applicable State and federal statutes and rules) requires the posting of bonds, letters of credit, or other financial assurance, Lessee shall remain responsible for satisfying such fiscal assurance requirements. Lessee's monitoring and financial assurance obligations under this Section 2.05 expressly survive the expiration or earlier termination of this Lease, provided however, notwithstanding the foregoing, such obligations shall terminate in accordance with applicable laws and regulations related to monitoring and financial assurances requirements; provided, further, that such obligations shall terminate at such time that the ownership of the CO2 is transferred to Lessor pursuant to Section 4.01(a). Following the end of the Term, Lessee shall retain all necessary and incidental rights to access the Property and the Facility to undertake all obligations required under this Lease or applicable law.

2.06 Authority of Lessor and No Warranty. Pursuant to Texas Natural Resources Code, Ch. 33, the SLB has the authority to lease the Property for the purposes set forth in this Lease and Lessor, which provides the staff for the SLB, confirms that, other than as set forth on Schedule 2.06 to this Lease, the SLB has not granted any conflicting rights on the Property to any other party. Subject to the foregoing, Lessee expressly accepts and assumes all risk and liability for penalty, civil or criminal fines or charges, or any other consequence, whether in connection with environmental damage, misreporting to governmental entities, or any other context, arising in connection with operation of the Project, including its ultimate closure. The obligations of Lessee under this section expressly survive expiration or earlier termination of this Lease.

ARTICLE III. Bonus Payments and Royalty

3.01 Bonus Payments and Royalty. During the Term of this Lease, Lessee shall pay consideration to Lessor as follows:

(a) Initial Bonus Payment. Within five (5) business days of the execution of this Lease, Lessee shall deliver, or cause to be delivered, to Lessor a wire transfer in the amount equal to $4,500,000.00 (the "**Initial Bonus Payment**").

(b) Second Bonus Payment. Within five (5) business days of the First Hurdle Date (defined below), Lessee shall deliver, or cause to be delivered, to Lessor a wire transfer in the amount equal to $4,500,000.00 (the "**Second Bonus Payment**").

(c) Third Bonus Payment. Within five (5) business days of the Second Hurdle Date (defined below), Lessee shall deliver, or cause to be delivered, to Lessor a wire transfer in the amount equal to $4,500,000.00 (the "**Third Bonus Payment**" and together with the Initial Bonus Payment and the Second Bonus Payment, the "Bonus Payments").

(d) Royalty. Lessee shall deliver, or cause to be delivered to Lessor, in each case as provided for in Section 3.03, (i) with respect to the Initial Injection Period, a monthly royalty equal to the product of the amount of Facility Proceeds for such month times three percent (3%), and (ii) with respect to the Subsequent Injection Period, a monthly royalty equal to the product of the amount of Facility Proceeds for such month times six percent (6%) (as applicable, the "**Royalty**" or "**Royalties**") (as Facility Proceeds, Initial Injection Period, and Subsequent Injection Period are defined below).

(e) True-Up Payment. Following the Second Hurdle Date, within thirty (30) business days following the end of each Lease Year, Lessee shall deliver, or cause to be delivered to Lessor, an annual payment (if any) equal to the following (as applicable, the "**True-Up Payment**"):

(i) with respect to each Lease Year during the Initial Injection Period, if the Standard Annual Volume exceeds the Annual Injected Volume for such Lease Year, the product of (A) the excess of the Standard Annual Volume over the Annual Injected Volume for such Lease Year, multiplied by (B) the Average Tonnage Price, multiplied by (C) three percent (3%), and

(ii) with respect to each Lease Year during the Subsequent Injection Period, if the Standard Annual Volume exceeds the Annual Injected Volume for such Lease Year, the product of (A) the excess of the Standard Annual Volume over the Annual Injected Volume for such Lease Year, multiplied by (B) the Average Tonnage Price, multiplied by (C) six percent (6%).

(iii) Notwithstanding the above, the calculation of the True-Up Payment shall be adjusted proportionally, day for day, based upon the number of days in the period ending prior to, on or after the occurrence of any of the following in a particular Lease Year: (i) the Second Hurdle Date, (ii) commencement of the Subsequent Injection Period, and/or (iii) the expiration of the Operations Term.

3.02 **Definitions**.

(a) **Annual Injected Volumes**. **"Annual Injected Volumes"** means the actual volume of CO2 injected into the Storage Unit during a given Lease Year.

(b) **Applicable Procedure**. **"Applicable Procedure(s)"** means the valid, final, and non-appealable standards, public processes, procedures, and rules applicable to the regulation of the Facility or the Project, to the extent applicable, by the U.S. Environmental Protection Agency ("**EPA**"), the Railroad Commission of Texas ("**RRC**"), the Texas Commission on Environmental Quality ("**TCEQ**"), and the Internal Revenue Service ("**IRS**") as well as any other state or federal regulatory bodies having jurisdiction over all or a part of the Facility or the Project.

(c) **Average Tonnage Price**. **"Average Tonnage Price"** means the average Facility Proceeds paid or delivered to Lessee, on a per metric ton of injected CO2 basis, over the relevant Lease Year. (Unless expressly provided otherwise, references in this Lease to a "ton", a "tonne", or a "metric ton/tonne" are deemed to mean a metric unit of mass equivalent to 1,000 kg.)

(d) **Carbon Credit**. **"Carbon Credit"** means any rights, credits, revenues, offsets, (including, without limitation Section 45Q Credits or other federal, state or local tax credits) , greenhouse gas rights or similar rights related to the production, capture or sequestration of CO2 or the ownership or operation of the Facility or the Project, including such rights to sell or trade any of the aforementioned domestically or internationally, and including the right to count or claim any applicable reductions pursuant to the Department of Energy's Climate Challenge Program, to register all such reductions pursuant to §1605 of the Energy Policy Act of 1992, and any other program of a governmental authority designed to encourage or reward the reduction of greenhouse gas emissions, provided, however, that "Carbon Credit" shall not include any "Subsequent Carbon Offsets" as defined below.

(e) **Facility Proceeds**. **"Facility Proceeds"** means the aggregate gross cash, cash equivalent, or other consideration paid or delivered to Lessee, without duplication, under all Injection Contracts, including, without limitation, any portion of a Carbon Credit that is assigned or the value of which is otherwise conveyed to Lessee by a third party or an affiliate of Lessee in return for Lessee's services under an Injection Contract; provided, however, for the avoidance of doubt, "Facility Proceeds" shall not include proceeds received by Lessee in connection with authorized transfers of this Lease or the Facility. Lessee will make commercially reasonable efforts to enforce its Injection Contracts, including with regard to Lessee receiving all of the consideration due to it under an Injection Contract.

(1) Cash Section 45Q Credits. If Section 45Q Credits are paid by the U.S Treasury in cash under then-applicable law, then such cash Section 45Q Credit payments shall be treated like

any other cash consideration, and shall be included in Facility Proceeds for Royalty calculation purposes by no later than the 12th month after such cash Section 45Q Credit is generated.

(2) Non-Cash Section 45Q Credits. With respect to any portion of the Facilities Proceeds in the form of non-cash Section 45Q Credits transferred to Lessee, (i) the value of such Section 45Q Credits shall be the federal cash tax savings recognized by the Lessee or its direct or indirect equity owners as a result of the utilization of the Section 45Q Credits, provided that if a cash contribution is received by Lessee in exchange for the future allocation of such Section 45Q Credits (e.g., a tax equity investment), the value of such Section 45Q Credits shall be the amount of cash received in exchange for such Section 45Q Credits, and (ii) the timing of the recognition of the value of the Section 45Q Credits shall be when such non-cash Section 45Q Credits have been utilized to offset cash tax liability or generated a contribution of cash to the Lessee in exchange for allocations of such Section 45Q Credits. If Lessor and Lessee fail to agree on the value of, or the timing of the recognition of, the reasonable non-cash Section 45Q Credits as defined in this Section 3.02(e) within 60 days after the last month of the Lease Year in which such Section 45Q Credits were transferred to the Lessee, the Parties shall refer such dispute to a mutually acceptable independent accounting firm (the "**Accounting Expert**"), and the Parties shall direct the Accounting Expert to make the determination of the value or timing of the non-cash Section 45Q Credits in dispute, and only such matter in dispute between the Parties, on a timely basis (and in any event within 60 days after its engagement) and to promptly notify the Parties in writing of its determination. The Parties shall provide the Accounting Expert all information reasonably necessary and available for the Accounting Expert to determine the value or timing of such non-cash Section 45Q Credits.

(3) Other Non-Cash Consideration. If any portion of the value to be paid to Lessee under an Injection Contract is in the form of an in-kind delivery (other than Section 45Q Credits), a non-arm's length cash payment from an affiliate of Lessee, or any other non-cash or cash equivalent consideration, then Lessor and Lessee will determine a cash value for such consideration based on the fair market value, arm's-length cash consideration to be paid to Lessee under its Injection Contract(s) during the applicable month (the "**Determined Cash Value**"). If Lessor and Lessee fail to agree on the Determined Cash Value within a reasonable amount of time after the last month of the Lease Year in which such amounts were includable in Facility Proceeds, the Parties shall refer such dispute to a mutually acceptable independent valuation expert (the "**Independent Expert**"), and the Parties shall direct the Independent Expert to make a determination as to the appropriate Determined Cash Value (and only such matter) on a timely basis (and in any event within 60 days after its engagement) and to promptly notify the Parties in writing of its determination. Thereafter, the Determined Cash Value shall be included in Facility Proceeds, as it is the intent of the Parties that the Royalty hereunder be applied in a timely manner against the full value received by Lessee for its service of transporting CO_2 to, and sequestering CO_2 in, the Storage Unit.

(4) Effect of Recaptured Amounts. Facility Proceeds for any month shall be reduced by any Recaptured Amounts for such month. If Facility Proceeds for any month is a negative dollar amount due to the reduction for any Recaptured Amounts in any month or otherwise, such negative dollar amount shall be carried forward and reduce the amount of Facility Proceeds in each subsequent month until such negative dollar amount is fully offset against future Facility Proceeds.

(f) First Hurdle Date. The "**First Hurdle Date**" means the date on which the aggregate volumes of CO_2 contractually committed to the Facility, pursuant to an Injection Contract, or Injection Contracts, whether or not such volumes have actually been injected into the Storage Unit, exceeds 4 million metric tons per annum. Lessee shall notify Lessor as and when volumes have been committed, although only the volumes, and not the identity of the emitter(s), need to be disclosed in such notices.

(g) **Initial Injection Period**. The "**Initial Injection Period**" means the period beginning immediately upon the Second Hurdle Date, and ending upon the date Lessee has injected an aggregate amount of 50 million metric tons of CO_2 in the Storage Unit.

(h) **Injection Contract**. An "**Injection Contract**" means a contract or agreement between Lessee and any third party for (i) the receipt, transportation, and/or injection of CO_2 by Lessee into any portion of the Storage Unit, or (ii) the re-delivery of CO_2 to Lessee. An Injection Contract may include a contract between Lessee and an affiliate of Lessee for the described service(s) so long as the proceeds payable to Lessee by an affiliate under such contract equal at least the proceeds payable to the affiliate by a third party under an arm's-length contract.

(i) **Lease Year**. A "**Lease Year**" means each successive twelve (12) month period commencing on the Effective Date.

(j) **Miocene Formation**. The "**Miocene Formation**" means all depths from the base of the Amphistegina B Shale, as found at 5,873 feet measured depth to the base of the Siphonina Davisi Sand as found at 8,765 feet measured depth, in each case, in the HI 4L Transco (Forest) #1 well (API No. 427083032500) located in Jefferson County, Texas State Waters (or the stratigraphic equivalent thereof, including each such stratigraphic equivalent shown on **Exhibit C**, recognizing that actual depths may vary across the Leased Property.

(k) **Plume.** The "**Plume**" means the physical and forecasted extent of the free-phase and dissolved CO_2 stream, in three dimensions, that has been injected into the Storage Unit.

(l) **Recaptured Amounts**. The "**Recaptured Amounts**" means the dollar amounts, if any, attributed to any Carbon Credits, the value of which were previously included in the definition of Facility Proceeds for purposes of calculating the Royalty paid to Lessor and which are subsequently recaptured or otherwise disallowed for the relevant period due to the actions or omissions of Lessor, the SLB, the PSF and/or any third party lessee of Lessor.

(m) **Second Hurdle Date**. The "**Second Hurdle Date**" means the first date on which Lessee actually injects CO_2 into the Storage Unit for permanent storage.

(n) **Section 45Q Credits**. The "**Section 45Q Credits**" means any tax credits under 26 U.S.C. § 45Q, as amended.

(o) **Standard Annual Volume**. The "**Standard Annual Volume**" means a volume of CO_2 equal to 1,000,000 metric tons.

(p) **Subsequent Injection Period**. The "**Subsequent Injection Period**" means the period beginning immediately upon the date Lessee has injected an aggregate amount of 50 million tons of CO_2 in the Storage Unit, and ending upon the termination of this Lease.

3.03 **Payments and Statements**. All Royalties that are required to be paid hereunder shall be due and payable sixty (60) days after the end of the month for each month during the Term (the "**Due Date**"), and shall be accompanied by a statement ("**Monthly Statement**") setting out the components of the Facility Proceeds and any Recaptured Amounts for the month for which Royalty is being paid. If Lessee and Lessor agree at any time that Royalties have been overpaid to Lessor (including as a result of any

Recaptured Amounts), Lessee shall recoup the overpaid Royalties by deducting the amount of the overpayment, without interest, from future Royalty payments; provided that if Royalty payments have concluded and Lessee has not recouped all Recaptured Amounts, Lessor shall be obligated to make a one-time payment to Lessee, without interest, for such Recaptured Amounts. Recoupment of overpaid Royalties shall be made as promptly as possible out of future Royalty payments. If the amount of agreed, overpaid Royalties and/or Recaptured Amounts to be recouped during any one month should exceed the amount of Royalties that otherwise would have been payable that month to Lessor, Lessee shall provide a written explanation to Lessor as to the nature and amount of the overpayment and the month during which it is reasonably expected that a resumption of Royalty payments to Lessor will occur. Lessor, at its option and in lieu of recoupment being made in the above manner, may promptly repay such overpayment in full or may request that the overpaid Royalties and/or Recaptured Amounts be recouped out of future Royalty payments on a mutually-agreeable schedule and in mutually-agreeable monthly amounts which will not create an undue hardship or burden on either Lessor or Lessee; provided that if Royalty payments have concluded and Lessee has not recouped all Recaptured Amounts, Lessor shall be obligated to make a one-time payment to Lessee, without interest, for such Recaptured Amounts. Lessor expressly reserves the right and Lessee expressly grants to Lessor the right to audit Facility Proceeds and the calculation and payment of Facility Proceeds upon Lessor giving Lessee notice of the exercise of this right. Within sixty (60) days after receipt of such notice, Lessee shall make available to Lessor during reasonable business hours all information requested by Lessor which in the commercially reasonable judgment of Lessor is reasonably necessary to audit such Facility Proceeds and the calculation and payment of Facility Proceeds in order that Lessor may fully and completely audit such Royalty. In the event the Parties reasonably dispute in good faith all or any portion of a Monthly Statement, then the undisputed portion, if any, shall be paid by the Due Date. Thereafter, the Parties shall cooperate with each other to resolve the dispute within sixty (60) days of the Due Date. In the event the Parties cannot reach agreement within 60 days of the Due Date (or earlier if by mutual written agreement), then the Parties will pursue resolution of the dispute pursuant to the terms of Section 10.11. The terms of this section shall survive expiration or earlier termination of this Lease.

3.04 Interest and Penalty. Any undisputed amount of Royalty that is not timely paid shall accrue simple interest at prime plus one percent (1%) per annum beginning on the date that the amount of unpaid Royalty is thirty (30) days overdue, and shall continue to accrue interest at that rate until paid (subject to the terms of this Lease, including Section 9.01(b)(ii), below, with regard to amounts determined to be due following an audit). For every month that a Monthly Statement or a monthly report described in Section 7.01, below, is not submitted when due as described in this Lease, each such non-filed report or Monthly Statement shall incur a penalty of $25 for every month (or part thereof) until filed. As used in this Section 3.04, "prime" means the prime interest rate, as published daily in the Wall Street Journal that is not a Saturday, Sunday, or legal holiday. For royalties due on a Saturday, "prime" shall refer to the prime interest rate published on the next business day that is not a legal holiday

ARTICLE IV. OWNERSHIP OF CO2

4.01 Ownership of Stored CO2.

(a) General. Subject to the terms of Section 4.01(b), below, regarding the use of stored CO2 in connection with Subsequent Carbon Offsets (as defined below), the CO2 transported to and stored in the Storage Unit remains the property and responsibility of Lessee or the generator or emitter of the CO2 according to the agreements between them, until such time as the SLB may elect to accept ownership of the CO2 pursuant to Texas Health & Safety Code, Sec. 382.507, or otherwise. Lessor, Lessee and/or the generator or emitter, as the case may be, even while owning the CO2, may not withdraw or make any other use of the CO2 in storage, including, without limitation, for enhanced recovery purposes, as the Parties agree that CO2 storage in the Storage Unit as contemplated by this Lease is intended to be permanent; provided, however, Lessee may withdraw certain amounts of CO_2 for the purpose of pressure maintenance or environmental or public safety concerns, in each case in accordance with Applicable Procedure and applicable law. Any Recaptured Amounts resulting from such a withdrawal will be borne entirely by Lessee. If the SLB has not previously elected to accept ownership of the CO_2, once (i) CO_2 has been delivered into storage into the Storage Unit, (ii) the Storage Unit has met all applicable state and federal requirements for closure of CO_2 storage sites, and (iii) Lessee has received the relevant "closure certificate" from the applicable state or federal regulatory agency, the SLB shall acquire title to the CO_2 stored in the Storage Unit and shall assume all obligations and liabilities with respect to such CO_2, and Lessee shall be released thereafter from all liabilities related to the ownership of the CO_2, provided that, notwithstanding the foregoing, delivery of CO_2 into the Storage Unit or acceptance of ownership of the CO_2 by the SLB on behalf of the PSF does not relieve Lessee of liability for any act or omission regarding the construction, operation, or closure, as applicable, of the Facility; except for such liabilities that (A) are the result of acts or omissions of Lessee that are actually known to and expressly accepted by Lessor, (B) could have been known by Lessor in the exercise of reasonable due diligence, or (C) are the result of acts or omissions occurring after the later of the date of receipt of such closure certificate or the date that the SLB acquires title to the stored CO_2.

(b) **<u>Subsequent Carbon Offsets</u>**. Notwithstanding anything herein to the contrary, the Parties acknowledge and agree as follows: (i) the CO_2 injected hereunder is to be permanently stored in the Storage Unit, (ii) all Carbon Credits associated with the capturing and permanent storage of CO_2 under this Lease are solely for the benefit of Lessee (or its designee), (iii) **LESSOR SHALL NOT TAKE ANY ACTION THAT WOULD INTENTIONALLY OR REASONABLY FORESEEABLY (A) MATERIALLY ADVERSELY IMPACT ANY OF THE LESSEE'S, EMITTERS', DIRECT OR INDIRECT MEMBERS OF AN EMITTER, THE LESSOR OR THE LESSEE, TAX EQUITY INVESTORS OR OTHERS ABILITY TO CLAIM, MAINTAIN, MONETIZE OR OTHERWISE RECEIVE THE BENEFIT OF, ANY CARBON CREDIT EARNED BY LESSEE, (B) RESULT IN ANY CARBON CREDIT TO BE SUBSEQUENTLY RECAPTURED OR OTHERWISE DISALLOWED, OR (C) RESULT IN ANY ACTIVITY THAT COULD RESULT IN A REVERSAL OR RELEASE OF CO2 FROM THE STORAGE UNIT (PROVIDED THAT SUCH RESULTING "ACTIVITY" IN (C) DOES NOT INCLUDE ACTS OR OMISSIONS OF ANOTHER LESSEE OF LESSOR THAT CONSTITUTE NON-COMPLIANCE BY THAT LESSEE OF ITS LEASE OBLIGATIONS)**. Subject to the foregoing and following the transfer of title of the permanently sequestered CO_2 from Lessee to Lessor, Lessor, at no expense to Lessee, shall have the sole and exclusive right to seek, market, receive, and retain in full any payment or other value that can be attributed to the permanently stored CO_2, including, without limitation, in connection with a monetization of carbon offset credits, or any and all other monetization of such permanently stored CO_2 (collectively herein, a "**Subsequent Carbon Offset**"), whether in connection with a recognized compliance system or otherwise; provided, that, such Subsequent Carbon Offsets do not adversely impact Lessee's ability to claim, maintain, monetize or otherwise receive the benefit of, any Carbon Credit. If Lessor does pursue a Subsequent Carbon Offset and such Subsequent Carbon Offset (x) adversely impacts any of Lessee's, emitters', direct or indirect members of an emitter, Lessor or Lessee, tax equity investors or others ability to claim, maintain, monetize or otherwise receive the benefit of, any Carbon Credit, (y) results in any Carbon Credit to be subsequently recaptured or otherwise disallowed, or (z) results in any activity that could result in a reversal or release of CO_2 from the Storage Unit, Lessor and Lessee may choose to resolve such matter pursuant to the dispute resolutions procedures in Section 10.11 hereof. Following a determination of the then-current dollar amount of such adverse impact (if any) pursuant to Section 10.11, such amount will either be paid by Lessor to Lessee, applied as a credit toward subsequent Royalty due hereunder, or some combination of both, at Lessor's discretion.

ARTICLE V. METERING

5.01 Mass Determination. The mass of CO2 injected into the Storage Unit shall be determined in accordance with Class VI monitoring and verification requirements and in accordance with the MRV and best industry practices.

5.02 Measuring Stations.

(a) Costs. The costs and expenses of installing, operating, and maintaining measuring stations (including all equipment, whether a single instrument or multiple instruments, necessary to determine the mass of stored CO2) required by this Lease shall be borne solely by Lessee.

(b) Location; Adequacy. The type, size, and location of Lessee's proposed metering for the Project are subject to the prior written approval of Lessor, such approval not to be unreasonably delayed or withheld. Lessee shall maintain one or more measuring stations, at least one of which must be located at the wellhead where the CO2 is injected, in part for purposes of Lessor's audit of Royalty paid hereunder. Lessee shall provide Lessor with summaries of plans and drawings for Lessee's proposed transportation and storage system, including information regarding meter locations and specifications, so that Lessor has sufficient information to assess the adequacy of Lessee's proposed metering for purposes of this Lease; provided, however, Lessor shall maintain such summaries of plans, drawings and information strictly confidential, and shall not disclose all or any portion of such summaries to any third party without the prior written consent of Lessee, which consent may be withheld in Lessee's discretion, which discretion is subject to Lessor's obligations under Section 10.16, below, the Texas Open Records Act, and any relevant order of a court of competent jurisdiction. Lessee's measurement and monitoring program and equipment must be (i) adequate to measure or monitor the mass of CO2 being injected into the Storage Unit, and (ii) in compliance with the testing and monitoring plan required by the Class VI Permit, the MRV, and as set forth in 40 CFR Section 146.90. Notwithstanding the foregoing provision regarding the qualified confidentiality of the summaries of Lessee's plans, drawings, and information, Lessor may analyze those materials, draw conclusions from them, and develop General Land Office best practices standards and requirements that may be shared by Lessor with the general public, including future CO2 storage space lessees, even if those General Land Office-developed "best practices" standards and requirements are, ultimately, identical or substantially similar to the plans for Lessee's transportation and storage system for the Facility.

(c) Standards. Each measuring station for CO2 mass delivered pursuant to this Lease shall be equipped in accordance with at least the standards (i) set forth in all applicable chapters of the American Petroleum Institute Manual of Petroleum Measurement Standards and (ii) of the American Gas Association. Subject to the prior approval of Lessor, measurement equipment will be subject to change to allow the use of improved technology under such standards.

5.03 Meter Calibration and Meter Tests. Lessee shall ensure that the measurement equipment for the Project is accurate and in good repair, and that such periodic tests of that equipment as Lessee may deem necessary are made as often as needed, and in accordance with standard industry measurement practices, provided that no more often than once every twelve (12) months Lessor may require such an equipment test by written notice thereof delivered to Lessee.

ARTICLE VI. MONITORING

6.01 Monitoring and Verification. Lessee shall adhere to all provisions of the approved MRV in addition to, and consistent with, all other applicable regulatory requirements and all other requirements of this Lease, including, but not limited to, the requirements of its Class VI Permit or other applicable UIC permit. The MRV plan shall be used to determine whether any CO2 is escaping from the Storage Unit and the amount of any such leakage. Lessee shall make all plans, models and reports required by the approved MRV, along with any associated supporting data, available to Lessor upon request. All reservoir models, well logs, well tests and other monitoring and verification studies performed on or for the Storage Unit shall be interpreted by a licensed professional engineer (or other qualified professional engineer or geoscientist who is approved by Lessor, such approval not to be unreasonably withheld), which may include Lessee personnel, and such interpretations shall be made available to Lessor upon written request; provided, however, Lessor shall maintain such models, well logs, well tests and other monitoring and verification studies and any interpretations with respect thereto strictly confidential, and shall not disclose all or any portion of such studies or interpretations to any third party, other than technical advisors or other consultants working with Lessor who have signed a reasonable non-disclosure agreement, without the prior written consent of Lessee, which consent may withheld in Lessee's sole discretion (provided that all of Lessor's foregoing obligations are subject to (A) the provisions of Section 10.16, and (B) the Texas Open Records Act and to any relevant order of a court of competent jurisdiction). Lessee shall permanently archive copies of all the aforementioned documents no later than the earliest of the closure date of the repository or the lease termination date. Notwithstanding the foregoing provision regarding the qualified confidentiality of the summaries of Lessee's studies and interpretations, Lessor may analyze those materials, draw conclusions from them, and develop General Land Office best practices standards and requirements, and such best practices and requirements may be shared by Lessor with the general public, including future CO2 storage space lessees provided that no such shared information contains any Lessee information or data.

6.02 **Seismicity**. Without limiting the foregoing, Lessee shall conduct an annual review of the seismicity relating to the Property and immediately adjacent land and report its findings to Lessor. If such findings indicate that seismicity is increasing in any particular location, Lessee will make commercially reasonable efforts to adjust its CO2 injection operations, using generally accepted engineering principles and industry practices, in order to reduce the possibility of the occurrence of damaging seismic activity.

ARTICLE VII REPORTING

7.01 **Reports with Payments**. During the Operations Term, Lessee shall submit to Lessor, at the same time that Royalty is paid, a report identifying the source(s) and mass of CO2 that has been gathered and injected into the Storage Unit during the period for which Royalty is being paid. Lessee shall submit to Lessor a copy of all filings and reports, when filed, that Lessee must file with the relevant governmental authority in connection with maintaining its Class VI Permit(s) or other applicable UIC permit(s).

7.02 **Statutory Reporting**. Pursuant to requirements of Texas Health and Safety Code, Ch. 382, at least annually, Lessee must submit a report to Lessor regarding the Project, including information regarding the measurement, monitoring, and verification of the permanent storage status of the CO2 stored in the carbon dioxide repository. Such information must include (i) the total mass of CO2 stored; (ii) the total mass of CO2 received for storage during the year; and (iii) the mass of CO2 received from each producer of CO2.

7.03 **Leaks**. Lessee acknowledges that its operation of the Project could damage the quality and quantity of storage pore space in the Property and/or in submerged lands outside of the Property which is owned by Lessor ("**Outside Lands**"). In order that Lessor can be informed regarding the condition of the Property and such Outside Lands, Lessee shall provide copies of reports no less often than every twelve (12) months during the entire Term of this Lease pertaining to (i) leak rates, (ii) leak detection (whether by pressure transient well tests or otherwise), or (iii) whether any such leaks have resulted in a migration of CO2 outside of the Property. Damage to the pore space in the Property and/or the Outside Lands caused by Lessee's operations hereunder, which damage is material and could have been foreseen and avoided by a reasonably prudent operator, shall be a Default hereunder and shall be subject to the procedures and remedies in Section 9.01(b)(iv) and Section 9.02.

7.04 **Other Agency Reporting Requirements**. If, at any time during the Term of this Lease, the Texas Commission on Environmental Quality, the Texas Railroad Commission, the GLO, or any other relevant State agency promulgates rules for the reporting of CO2 storage, then Lessee must (i) comply with those rules to the extent applicable, and (ii) send to Lessor a true and complete copy of any report or information provided to such State agency in compliance with such rules.

VIII LESSEE'S REPRESENTATIONS

8.01 **Lessee's Representations**. Lessee hereby represents and warrants to Lessor that (i) Lessee is authorized to do business in the State of Texas, (ii) entering into this Lease is an action duly authorized on behalf of Lessee by its management and in accordance with its organizational documents, and (iii) the person executing and delivering this Lease has the requisite authority to bind Lessee to Lessee's obligations hereunder.

IX DEFAULT AND REMEDIES

9.01 **Default by Lessee; Notice and Cure; Removal and Restoration**.

(a) **Default**. Subject to the notice and cure provisions below, if Lessee is not in material compliance with the terms of this Lease, including, without limitation, the terms of this Lease that require payment of any Bonus Payment or Royalty, that require the maintenance of necessary permits, that require compliance with applicable laws and regulations, and that limit the use that may be made of the Property by or on behalf of Lessee, Lessee shall be in "Default" hereunder.

(b) **Notice and Cure**.

(i) If, based on the corresponding Monthly Statement, the Royalty paid in any given month (A) has been underpaid, then Lessee shall pay the underpayment to Lessor within thirty (30) days of Lessor's notice to Lessee of such underpayment, or (B) has been overpaid, then Lessee may credit such overpayment against its next Royalty payment, and shall also provide Lessor with an explanation of such overpayment and credit. If (1) Lessee does not timely pay such underpayment, and (2) there exists no good faith dispute between the Parties regarding such underpayment, Lessee shall be in Default hereunder. The Parties may agree to resolve any good faith dispute arising under this Section 9.01 pursuant to the dispute resolution procedures in Section 10.11 hereof.

(ii) If, following an audit pursuant to Section 10.05, below, Lessor determines that Royalty for any given period of time that was audited for the sixty (60) month period prior to the audit has been underpaid, Lessor will send to Lessee a final audit billing notice setting out the amount of Royalty, penalty (pursuant to Section 3.04, above), and interest due. The Parties will then proceed in accordance with the terms of Tex. Nat. Res. Code, Sec. 52.135(b) – (d) (pertaining to audits regarding payment of royalty for oil and gas production). If Lessee does not pay, within thirty (30) days of a final decision, the amounts, if any, that are determined to be due following that statutory process, then Lessee shall be in Default hereunder.

(iii) If Lessee receives notice from any governmental entity that Lessee is in non-compliance with the terms of any permit that it has received from that governmental entity for the construction and/or operation of the Facility (a "**Notice of Non-Compliance**"), then Lessee will promptly provide to Lessor a copy of such Notice of Non-Compliance. If Lessee does not remedy the non-compliance in the manner and within the time set out in the Notice of Non-Compliance, then the provisions of Section 9.01(b)(iv) shall control.

(iv) If Lessor determines in its reasonable judgment that Lessee is operating the Facility in an unsafe manner and such operations could have been foreseen or avoided by a reasonably prudent operator (such as, e.g., but without limitation, by exceeding pressure limitations or damaging capacity potential), then Lessor shall notify Lessee in writing of the unsafe operation and Lessor may immediately seek a temporary injunction to prevent damage to Lessor's Property. Subject to the outcome of Lessor's temporary injunction request (if any), Lessee shall have thirty (30) days after receipt of such notice within which to (A) correct or cease such operations to the extent that Lessor has identified the operations to be unsafe (including damaging), or (B) explain to Lessor's reasonable satisfaction that Lessee's operation of the Facility is not unsafe. If Lessee has not corrected in all material respects or ceased its unsafe operations within thirty (30) days of Lessor's notice, as described in (A), or, if Lessor is not satisfied with Lessee's explanation within thirty (30) days after Lessor's receipt of Lessee's explanation, as described in subpart (B) above, then the Parties may seek to resolve such matters pursuant to Section 10.11 hereof.

(v) If Lessor determines in its reasonable judgment that Lessee is in Default of this Lease for any reason other than as described in the foregoing (i) – (iv), Lessor shall notify Lessee in writing of the alleged Default of this Lease and Lessee shall have thirty (30) days after receipt of such notice within which to correct, commence actions to correct or dispute all or any part of the alleged Default as to which Lessee has been notified and shall pursue the remedy of such alleged Default, if any, in good faith and with reasonable diligence until completion. If such Default is not corrected in all material respects within the 30-day period (or, in the case of a Default that is not susceptible to cure within 30 days, correction is not commenced within 30 days and then pursued diligently to completion), Lessee shall be in Default hereunder, provided, however, that if Lessee has disputed the Default within thirty (30) days after receipt of Lessor's notice, then the Parties will proceed to mediation with a mutually agreed-upon impartial third party as provided in Section 9.01(b)(iv) above.

9.02 **Lessor's Remedies**. Subject to the terms of Section 9.01(b), Lessor shall have, as a remedy for Lessee's Default hereunder, all remedies available to it in law or in equity except as any such remedy may be limited by the express terms of this Lease, including, at Lessor's sole discretion, the right to terminate this Lease and all rights inuring to Lessee hereunder by sending written notice of such termination to Lessee in accordance with this Lease. Upon sending of such written notice of termination, this Lease shall automatically terminate and all rights granted herein to Lessee shall revert to Lessor. Such termination shall not prejudice the rights of Lessor to collect any money due or to seek recovery on any claim arising hereunder, and nor shall any such termination relieve Lessee of its obligations hereunder that survive expiration or earlier termination of this Lease.

9.03 **Removal of Property; Restoration**. Upon expiration or earlier termination of this Lease, at Lessor's sole option, Lessee shall (1) convey all personal property and improvements of Lessee on the Property to Lessor, or (2) (A) restore the Property to its original topographical condition that existed as of the Effective Date, and (B) remove all personal property and any improvements placed or constructed on the Property by or on behalf of Lessee from the Property, except in each case to the extent such personal property or improvements are reasonably necessary for the closure of the Facility. The terms of this section shall survive expiration or earlier termination of this Lease. Lessor and Lessee agree that, in the event

Lessee fails to restore the Property or remove its personal property or improvements within the time specified in a notice provided pursuant to this Section 9.03, then Lessor may, at its sole option, remove and dispose of such property (with no obligation to sell or otherwise maintain such property in accordance with the Uniform Commercial Code), at Lessee's sole cost and expense, or Lessor may elect to own such property by written notice of such election provided. If Lessor makes an election under subpart (1) or (2) above and Lessee fails to comply with its obligations under this Section 9.03, then in such an event Lessor may restore the Property to its original topographical condition that existed as of the Effective Date, and remove all personal property and any improvements placed or constructed on the Property by or on behalf of Lessee from the Property, and Lessee shall be obligated to reimburse Lessor for the reasonable costs of such restoration, removal and disposal within ten (10) days of Lessor's demand for reimbursement. The terms of this section shall survive expiration or earlier termination of this Lease.

9.04 Default by Lessor. Notwithstanding any other provision of this Lease, if Lessor fails to perform any material obligation or breaches any covenant made to Lessee hereunder which, if capable of being cured, is not cured within thirty (30) days from the date that Lessee provides notice that corrective action is needed, Lessee may, in addition to all other remedies available to it, withhold or suspend payment of any amount due hereunder without prior notice to Lessor.

X MISCELLANEOUS

10.01 Taxes and Fees.

(a) Responsibility. Lessor represents that it is exempt from taxation. Lessee shall timely pay all taxes imposed on Lessee that, if unpaid, would result in a lien or other encumbrance on the Property and that would adversely impact Lessor's interest in the Property, provided, however, that Lessee may, in good faith, and at its sole cost, contest any such taxes or assessments, and shall be obligated to pay the contested amount only if and when finally determined to be owed by the applicable governmental authority.

(b) Proceedings. Lessee may (but is not required to) prosecute any administrative or judicial proceedings relating to the Project and the rights conveyed herein including, but not limited to, contesting any taxes or fees assessed or levied upon the Project as a result of Lessee's equipment, leasehold or easement interest, or operations hereunder. With the express prior written consent of Lessor, Lessee may undertake any administrative or judicial proceeding in the name of Lessor.

10.02 Force Majeure. If, and while, operation of the Project is delayed or interrupted as a result of events beyond the reasonable control of Lessee, such as (but not limited to) hurricanes, floods, other acts of God, fire, war, pandemic, or action or inaction by any governmental authority other than Lessor, Lessee shall be excused from non-performance (including the payment of any True-Up Payment, if applicable) during the pendency of the direct interruptive effect of such events on operations at the Facility.

10.03 As Is, Where Is. LESSEE HAS HAD THE OPPORTUNITY TO INSPECT THE PHYSICAL AND TOPOGRAPHIC CONDITION OF THE PROPERTY AND ACCEPTS SAME "AS IS" IN ITS EXISTING PHYSICAL AND TOPOGRAPHIC CONDITION. LESSEE IS NOT RELYING ON ANY REPRESENTATION OR WARRANTY OF THE LESSOR REGARDING ANY ASPECT OF THE PROPERTY, BUT IS RELYING ON LESSEE'S OWN INSPECTION OF THE PREMISES AND PROPERTY. LESSOR DISCLAIMS ANY AND ALL WARRANTIES OF HABITABILITY, MERCHANTABILITY, SUITABILITY, FITNESS FOR ANY PURPOSE, AND ANY OTHER WARRANTY WHATSOEVER NOT EXPRESSLY SET

FORTH IN THIS LEASE. LESSEE WILL MAKES ITS OWN DETERMINATION OF THE USABILITY OF THE PROPERTY FOR THE PROJECT. LESSEE IS HEREBY PUT ON NOTICE THAT ANY PRIOR GRANTS OF RIGHTS AND/OR ENCUMBRANCES MAY BE OF RECORD AND LESSEE IS ADVISED TO EXAMINE ALL RECORDS OF THE STATE AND COUNTY IN WHICH THE PROPERTY IS LOCATED. THE USE OF THE TERMS "GRANT" AND/OR "CONVEY" EXPRESSLY DO NOT IMPLY OR CREATE ANY WARRANTIES OF TITLE. THE TERMS OF THIS SECTION SHALL SURVIVE EXPIRATION OR EARLIER TERMINATION OF THIS LEASE.

10.04 **Notices**. All notices given pursuant to this Lease shall be in writing, and may be sent by (a) first class U.S. mail postage prepaid, certified, return receipt requested or (b) overnight mail, in each case addressed to the Party to be notified at the address listed for such Party above. The date that the certified letter is signed for or refused by the recipient, or, as applicable, the overnight mail is delivered to or refused by the recipient is the date that the notice is "received" under this Lease, including for purposes of Section 9.01(b), above. A copy of such notice shall also be provided by email, if to Lessor, to the Deputy Director of Energy Resources for the Texas General Land Office, or other express designee of Lessor, and if to Lessee, to the attention of the Executive Vice President and General Counsel. A Party may change its address for notice by giving notice to the other Party.

10.05 **Audits**. Lessor shall have the right, no more than once per Lease Year, personally or by representative, to inspect the proprietary books, accounts, contracts, records and data of Lessee solely as they pertain to the operation of the Project (including permit status), storage of CO_2 in the Storage Unit, calculation of the Royalty (including all documents and information related to Facility Proceeds and Recaptured Amounts), and any other matter reasonably deemed subject to the terms of this Lease so long as such audit process is conducted during regular business hours at Lessee's principal place of business; provided however, Lessee shall not be required to provide any copies of Lessee's proprietary books, accounts, contracts, records and data for review by Lessor outside of Lessee's principal place of business.

10.06 **Memorandum of Lease**. Lessee shall, at its sole cost and expense, record a Memorandum of Lease in the form of **Exhibit B** attached hereto (the "**Memorandum**") in the Official Public Records of the county or counties in which the Property is located and provide a file marked copy of same to Lessor within sixty (60) days after this Lease is executed by all Parties.

10.07 **Counterparts**. This Lease may be executed in counterparts, each of which shall be considered an original for all purposes.

10.08 **Assignments**. The interests of Lessor under this Lease may be freely assigned. The interests of Lessee under this Lease may be assigned on the prior written consent of Lessor (not to be unreasonably withheld, conditioned, delayed, or denied), but not otherwise; provided, however, the interests of Lessee may, upon written notice thereof provided to Lessor, be freely assigned without the prior consent of Lessor to any affiliate of Lessee that agrees in writing to assume and be bound by the obligations of "Lessee" hereunder (with a copy of such assumption provided to Lessor). For purposes of the foregoing, an "affiliate" of Lessee is an entity that (i) owns more than 50% of, or otherwise has a controlling managerial interest in, Lessee, (ii) is more than 50% owned by, or is controlled by, Lessee, or (iii) is under common ownership and control with Lessee in a single "family" of entities ultimately owned and controlled by the same entity.

10.09 Protection of Natural and Historical Resources. **LESSEE IS EXPRESSLY PLACED ON NOTICE OF THE NATIONAL HISTORICAL PRESERVATION ACT OF 1966 (16 USC § 470, ET SEQ.) AND THE TEXAS ANTIQUITIES CODE (TEX. NAT. RES. CODE CH. 191), AS THE SAME MAY BE AMENDED FROM TIME TO TIME. IN THE EVENT THAT ANY SITE,**

OBJECT, LOCATION, ARTIFACT OR OTHER FEATURE OF ARCHEOLOGICAL, SCIENTIFIC, EDUCATIONAL, CULTURAL OR HISTORIC INTEREST IS ENCOUNTERED DURING ANY ACTIVITY ON ANY PORTION OF THE PROPERTY OWNED IN FEE BY LESSOR, LESSEE SHALL IMMEDIATELY CEASE SUCH ACTIVITIES AND SHALL IMMEDIATELY NOTIFY LESSOR AND THE TEXAS HISTORICAL COMMISSION, P.O. BOX 12276, AUSTIN, TEXAS 78711, SO THAT ADEQUATE MEASURES MAY BE UNDERTAKEN TO PROTECT OR RECOVER SUCH DISCOVERIES OR FINDINGS, AS APPROPRIATE. IN THE EVENT LESSEE IS REQUIRED TO CEASE ACTIVITIES UNDER THE LEASE AS TO ANY PORTION OF THE PROPERTY, THE TRUE-UP PAYMENT SET FORTH IN SECTION 3.01(E) SHALL NOT APPLY FOR ANY PERIOD FOR WHICH LESSEE IS REQUIRED TO CEASE ACTIVITIES.

10.10 **Governing Law and Venue; Compliance with Laws**. This Lease shall be governed by the laws of the State of Texas. Exclusive venue for any dispute arising under or relating to this Lease shall be in any court of competent jurisdiction in Travis County, Texas. Lessor and Lessee agree that each of them will comply with all applicable federal, state and local laws and all applicable ordinances, rules, orders, and regulations of any authority having jurisdiction over the activities of Lessor or Lessee under this Lease.

10.11 **Non-Binding Mediation**. The Parties may agree at any time to mediate any dispute arising under Section 3.03, 4.01 or 9.01 of this Lease through an impartial third party. If both Parties agree to mediation, (i) the Parties will convene within a reasonable time with a professional mediator mutually agreed upon by the Parties, and (ii) representatives of each Party will make reasonable efforts to attend meetings and participate in telephone conferences or video conferences as reasonably requested by either Party. If (A) the dispute is not resolved within thirty (30) business days after the first convening with a mediator as described above, or (B) the Parties cannot agree to mediate, either Party may declare an impasse, which will conclude the mediation process. Thereafter, the Parties shall be entitled to seek all remedies available at law or in equity. Nothing in this Lease, including in this Section 10.11, shall be construed as a waiver by Lessor of its sovereign immunity from suit of from damages.

10.12 **Further Assurances**. The Parties shall take all further actions and shall execute and deliver to the other any document or instrument which is necessary to fully carry out the transactions contemplated by this Lease. The Parties shall cooperate with each other and act in good faith to accomplish the purposes of this Lease.

10.13 **Lessee Liability. LESSEE SHALL BE FULLY LIABLE AND RESPONSIBLE FOR ANY DAMAGE, OF ANY NATURE, ARISING OR RESULTING FROM ITS OWN ACTS OR OMISSIONS RELATED TO ITS EXERCISE OF THE RIGHTS GRANTED HEREIN. LESSEE AGREES TO AND SHALL INDEMNIFY AND HOLD LESSOR, LESSOR'S OFFICERS, AGENTS, AND EMPLOYEES, HARMLESS FROM AND AGAINST CLAIMS, SUIT, COSTS, LIABILITY OR DAMAGES OF ANY KIND, INCLUDING STRICT LIABILITY CLAIMS, WITHOUT LIMIT AND WITHOUT REGARD TO CAUSE OF THE DAMAGES OR THE NEGLIGENCE OF ANY PARTY, AND WHETHER FOR DAMAGES TO PROPERTY OR THE ENVIRONMENT OR INJURY OR DEATH OF ANY PERSON, OR ANY COMBINATION THEREOF, EXCEPT FOR THE CONSEQUENCES OF THE GROSSLY NEGLIGENT ACTS OR WILLFUL MISCONDUCT OF LESSOR, LESSOR'S OFFICERS, AGENTS, OR EMPLOYEES, ARISING DIRECTLY OR INDIRECTLY FROM LESSEE'S OPERATION OF THE PROJECT, INCLUDING ITS SOLE USE OF THE PROPERTY AND THE FACILITY (OR ANY ADJACENT OR CONTIGUOUS PSF LAND) OR FROM ANY BREACH BY LESSEE OF THE TERMS CONTAINED HEREIN. THE PROVISIONS OF THIS SECTION SHALL SURVIVE EXPIRATION OR EARLIER TERMINATION OF THIS LEASE.**

10.14 **Lessee Insurance**. Lessee shall obtain and maintain at all times during the Term of this Lease all of the insurances, and in the amounts, as were required pursuant to the RFP.

10.15 **Oil, Gas, and Other Assets Disclaimer**. The only rights pertaining to any asset of Lessor granted to Lessee under this Lease are those expressly set out herein with regard to construction, operation, and closure of the Facility on the Leased Property. Without limitation, and notwithstanding anything in this Lease to the contrary, the Parties acknowledge and agree Lessee shall in no way be entitled to any oil and/or gas rights owned or otherwise held by Lessor, and that this Lease shall in no way be construed as an agreement between Lessor and Lessee with respect to such oil and gas rights or interests or the production, sale, transfer or treatment of oil, gas or other hydrocarbons. Further, as between Lessor and Lessee, and subject to Section 10.16, Lessor (or its lessees, pursuant to agreements between them) shall retain all responsibility and obligation related to existing, or future, oil, gas or other mineral development on the Property including producing, shut-in or non-producing wells, platforms, pipelines and related infrastructure and equipment of any kind.

10.16 **Lessee's Information**. The Parties acknowledge that this Lease and Lessee's documents provided in compliance with this Lease, including information that may be provided in compliance with provisions in Section 2.03, Section 5.02, and Section 6.01 ("**Lessee's Information**") may be subject to the Texas Public Information Act as set forth in Chapter 552 of the Texas Government Code. Lessee shall have the right, as a third party, to seek to withhold all or part of Lessee's Information, including as set forth in Section 7.1.6 of the RFP, and to seek a determination from the Texas Attorney General in accordance with the Texas Public Information Act prior to the release of any Lessee Information. Lessor agrees to timely notify, and to reasonably cooperate with, including as set forth in Section 7.1.6 of the RFP, Lessee of any request for the release of Lessor's Information. Such reasonable cooperation shall include withholding information provided by Lessee to Lessor in compliance with this Lease pending any such determination by the Attorney General. Additionally, if the Parties agree that a request for Lessee's Information may be the subject of a shared exception to the Public Information Act, including homeland security, geological, or other exception, Lessor agrees to separately pursue a determination of the confidentiality from the Attorney General of the requested information.

10.17 **Miscellaneous**. This Lease may not be amended except in a writing signed by Lessor and Lessee. Nothing in this Lease shall be construed as creating any form of partnership of joint venture relationship between the Parties. No third party shall be deemed a third party beneficiary of this Lease. This Lease (which specifically incorporates the non-conflicting terms of the RFP, as described above) constitutes the entire agreement between Lessor and Lessee and supersedes all oral statements and prior understandings relating to the subject matter contained in this Lease. Except as set forth in this Lease, no representations, warranties, or agreements have been made by either Party to the other Party with respect to this Lease. If any part of this Lease is illegal, invalid or unenforceable under present or future laws, then the remainder of this Lease shall not be affected and in lieu of such part there shall be added a clause or provision as similar in terms to such illegal, invalid, or unenforceable part as may be legal, valid, and enforceable, and any affected part shall be severed from this Lease if necessary to enforce the remainder of this Lease.

10.18 **Change-in-Law.** Notwithstanding anything to the contrary herein, the Parties agree to negotiate in good faith for the purposes of amending this Lease in the future in order to (a) ensure compliance with existing, amended, and/or future rules, regulations, and/or administrative guidance promulgated by the EPA, RRC, TCEQ, IRS, Lessor, or any other regulatory or administrative body having jurisdiction and/or authority over tax credits, economic incentives, or other revenue generating structures applicable to Lessee's business and operations, consistent with Lessee's desire to execute a successful carbon capture and sequestration project; (b) ensure compliance with the all applicable law(s) or Applicable Procedure(s); or (c) address operational, market or commercial matters related to carbon capture and sequestration projects. Further, the Parties agree to cooperate in good faith in connection with Lessee obtaining regulatory approvals and additional amendments to this Lease to expand the Property covered by this Lease if the Plume migrates through a pathway unpredicted by the storage reservoirs modeling into adjacent state-owned land or water bottoms (to the extent such additional acreage is available).

10.19 **Lender Protections.** Notwithstanding anything to the contrary contained in this Lease, Lessee shall have the right to grant one or more liens against, or security interests in, (i) any improvements and/or equipment of Lessee, and/or (ii) Lessee's leasehold interest in the Property, in each case, as security for any indebtedness of Lessee or its affiliates. In this regard, Lessor hereby agrees to use commercially reasonable efforts (without the obligation to incur any out-of-pocket expenses) to cooperate with Lessee's efforts in obtaining and maintaining financing for (x) the construction of the Storage Unit and any related improvements and/or equipment, (y) Lessee's leasehold interest under this Lease, and/or (z) Lessee's operations to be conducted on the Property. Furthermore, Lessor shall execute and deliver to Lessee any documents reasonably required by a title insurance company, a financing party or a third party, including estoppel certificates, in form and substance reasonably acceptable to Lessee, within ten (10) business days after presentation of said documents by Lessee; provided, however, that in no event shall such documents materially increase any obligation or materially decrease any right of Lessor hereunder.

[SIGNATURE PAGE FOLLOWS]

Given under my hand and Seal of Office

LESSOR

The State of Texas

By: DocuSigned by: 7C299F4374E7497...

Chief Clerk and Deputy Land Commissioner,
Texas General Land Office
On behalf of the Permanent School Fund

LESSEE

Bayou Bend CCS LLC

By:
Name: Tim Duncan
Title: President and Chief Executive Officer

APPROVED:

Staff: DS
Dir.: DS
OGC: DS
Exec.: DS

STATE OF TEXAS §
§
COUNTY OF HARRIS §

This instrument was acknowledged before me on March 11, 2022, by Tim Duncan, President and Chief Executive Officer of Bayou Bend CCS LLC, a Delaware limited liability company, on behalf of said limited liability company.

JULIE PRATT
My Notary ID # 124482915
Expires December 27, 2024

Notary Public in and for the State of Texas

EXHIBIT A

DESCRIPTION OF PROPERTY

All of Tract 5-S, Gulf of Mexico, Jefferson County, containing approximately 851.08 acres; and
All of Tract 6-S, Gulf of Mexico, Jefferson County, containing approximately 867.07 acres; and
All of Tract 7-S, Gulf of Mexico, Jefferson County, containing approximately 884.92 acres; and
All of Tract 8-S, Gulf of Mexico, Jefferson County, containing approximately 888.69 acres; and
All of Tract 22-S, Gulf of Mexico, Jefferson County, containing approximately 640.16 acres; and
All of Tract 23-S, Gulf of Mexico, Jefferson County, containing approximately 640.05 acres; and
All of Tract 24-S, Gulf of Mexico, Jefferson County, containing approximately 640.12 acres; and
All of Tract 25-S, Gulf of Mexico, Jefferson County, containing approximately 640.20 acres; and
All of Tract 34-S, Gulf of Mexico, Jefferson County, containing approximately 640.14 acres; and
All of Tract 35-S, Gulf of Mexico, Jefferson County, containing approximately 640.31 acres; and
All of Tract 36-S, Gulf of Mexico, Jefferson County, containing approximately 640.11 acres; and
All of Tract 37-S, Gulf of Mexico, Jefferson County, containing approximately 640.14 acres; and
All of Tract 38-S, Gulf of Mexico, Jefferson County, containing approximately 640.12 acres; and
All of Tract 39-S, Gulf of Mexico, Jefferson County, containing approximately 640.15 acres; and
W/2 of Tract 2-L, Gulf of Mexico, Jefferson County, containing approximately 2,881.33 acres; and
All of Tract 3-L, Gulf of Mexico, Jefferson County, containing approximately 5,761.42 acres; and
All of Tract 4-L, Gulf of Mexico, Jefferson County, containing approximately 5,761.59 acres; and
E/2 of Tract 5-L, Gulf of Mexico, Jefferson County, containing approximately 2,880.66 acres; and
E/2 of Tract 10-L, Gulf of Mexico, Jefferson County, containing approximately 2,880.45 acres; and
W/2 and N/2 NE/4 of Tract 11-L, Gulf of Mexico, Jefferson County, containing approximately 3,601.11 acres; and
N/2 NW/4 and NE/4 of Tract 12-L, Gulf of Mexico, Jefferson County, containing approximately 2,160.62 acres; and
W/2 of Tract 13-L, Gulf of Mexico, Jefferson County, containing approximately 2,880.74 acres; and
N/2 NE/4 and N/348.6 of S/2 of NE/4 of Tract 21-L, north of Three Marine League line, Gulf of Mexico, Jefferson County, containing approximately 1,068.92 acres; and
N/2 NW/4 and N/374.14 of S/2 of NW/4 of Tract 20-L, north of Three Marine League line, Gulf of Mexico, Jefferson County, containing approximately 1,094.24 acres.

EXHIBIT B

Form of Memorandum

See attached.

EXHIBIT B
FORM OF MEMORANDUM

NOTICE OF CONFIDENTIALITY RIGHTS: IF YOU ARE A NATURAL PERSON, YOU MAY REMOVE OR STRIKE ANY OF THE FOLLOWING INFORMATION FROM THIS INSTRUMENT BEFORE IT IS FILED FOR RECORD IN THE PUBLIC RECORDS: YOUR SOCIAL SECURITY NUMBER OR YOUR DRIVER'S LICENSE NUMBER.

MEMORANDUM OF LEASE

State:	Texas
County:	Jefferson
Lessor:	State of Texas General Land Office 1700 North Congress Avenue Austin, TX 78701
Lessee:	Bayou Bend CCS LLC
Effective Date:	April 1, 2022

1. This Memorandum of Lease (this "Memorandum") is entered into effective as of April 1, 2022 (the "Effective Date") by and between the State of Texas, acting by and through the Commissioner of the Texas General Land Office ("Lessor") and Bayou Bend CCS LLC ("Lessee"). Lessor and Lessee are hereinafter sometimes referred to singularly as a "Party" and collectively as the "Parties". Capitalized terms used in this Memorandum but not defined herein have the meaning ascribed to such terms in the Lease (defined below).

2. The Parties hereby acknowledge and give notice that Lessor and Lessee have entered into a Carbon Dioxide Transportation and Storage Lease dated April, 1 (the "Lease"), related to carbon dioxide sequestration operations by Lessee in, on, and under certain the Permanent School Fund lands in Jefferson County, Texas, which lands are more fully described in **<u>Exhibit A</u>** attached hereto (the "Leased Property"). In addition to the lease of the Leased Property to Lessee, Lessor hereby agrees that it will grant to Lessee the necessary easements, ingress and egress rights, rights-of-way, and surface locations over, across, and under certain tracts of land owned by the Permanent School Fund (the "Easement Tracts"), for the construction, installation, maintenance, and operation of pipelines, meters, and related equipment which are necessary for the transportation of CO2 from its source to the Leased Property and the measurement thereof. The Parties hereby agree to amend **<u>Exhibit A</u>** to this Memorandum to reflect any Easement Tracts conveyed by Lessor to Lessee. The Leased Property and the Easement Tracts are, collectively referred to herein and therein as, the "Property".

3. The Lease has been duly executed by Lessor and Lessee, but it has not been filed of record in the County Clerk's office of Jefferson County, Texas. Duplicate originals of the Lease are in possession of the Lessor and Lessee.

4. In the Lease, Lessor grants, leases and lets unto Lessee the exclusive right to geologically store anthropogenic carbon dioxide ("CO2") in a reservoir(s) and pore space in the

Miocene Formation (as such term is defined under the most expansive definition required to ensure certification or classification of the CO2 sequestration as permanent under any protocols, standards, regulations or laws relevant to Lessee and its storage activities conducted pursuant to the Lease , the "Storage Unit"), together with the exclusive right to drill and to construct, maintain, and operate pipelines, flowlines, wells, fixtures, machinery, and any other equipment Lessee deems necessary for the purposes herein and in connection with such geologic storage (such Storage Unit, together with associated pipelines, wells, fixtures, machinery, and equipment, called the "Facility" herein, and the permitting, construction, and operation of the Facility, sometimes called the "Project" herein). It is the intent of Lessor and Lessee that all equipment, pipe, supports, facilities, meters, systems and ancillary items placed or maintained by Lessee on the Property shall be considered part of the Facility and shall be owned and controlled by Lessee except as provided for in the Lease.

5. The Term (as used herein) of the Lease begins on April 1, 2022, and shall consist, collectively, of each of the Development Term, Construction Term, and Operations Term, as well as the accompanying Development Term Extension Period and Construction Term Extension Period (as those terms are defined in the Lease), as well as the closure and monitoring period following the Operations Term.

6. The Lease contains certain payment terms and obligations, as well as specific termination rights exercisable by one or more of the Parties.

7. Section 1.05(a) of the Lease provides, in part, that during the Term, under no circumstance shall any well bore be drilled through the Storage Unit, nor shall the Storage Unit be exposed to communication with any well bore (each of which, a "Drill-Through Restriction"). PRIOR TO CONDUCTING ANY HYDROCARBON DRILLING OR EXTRACTION ACTIVITIES ON OR NEAR THE PROPERTY, A LESSEE OR OPERATOR OF A STATE LEASE OR OPERATING AGREEMENT MUST FORBEAR FROM ANY ACTIVITIES THAT VIOLATE OR POTENTIALLY VIOLATE THE DRILL-THROUGH RESTRICTIONS.

8. Section 1.05(b) of the Lease provides, in part, that as a condition of any future state lease on any part of the Property or the grant of any lease, easement or access rights to the Property, Lessor shall require the lessee or holder of such lease, easement or access rights to expressly indemnify and defend Lessee for all claims for damages or losses (including losses attributable to Carbon Credits previously realized by Lessee which are recaptured or otherwise disallowed) that Lessee may suffer or incur as a result of such party's activities, including such losses or damages, including legal fees, that result from any Leak Event. Such indemnity shall be (A) set forth in a separate written agreement between Lessee and the lessee or holder of such lease, easement or access right, and (B) be backed by adequate financial security (i.e. posting of bonds, letters-of-credit, or other financial assurance) in favor of Lessee and its designees, in each case of (A) and (B), in a form reasonably acceptable to Lessee. PRIOR TO CONDUCTING ANY HYDROCARBON DRILLING OR EXTRACTION ACTIVITIES ON OR NEAR THE PROPERTY, A LESSEE OR OPERATOR OF A STATE LEASE OR OPERATING AGREEMENT SHALL (1) DELIVER A SEPARATE WRITTEN INDEMNITY AGREEMENT TO LESSEE, AND (2) OBTAIN ADEQUATE FINANCIAL SECURITY IN FAVOR OF

LESSEE AND ITS DESIGNEES, IN EACH CASE OF (1) AND (2), IN SUBSTANCE AND FORM REASONABLY ACCEPTABLE TO LESSEE.

9. The interests of Lessor under the Lease may be freely assigned. The interests of Lessee under the Lease may be assigned on the prior written consent of Lessor (not to be unreasonably withheld, conditioned, delayed, or denied), but not otherwise; provided, however, the interests of Lessee may, upon written notice thereof provided to Lessor, be freely assigned without the prior consent of Lessor to any affiliate (as such term is defined in the Lease) of Lessee that agrees in writing to assume and be bound by the obligations of "Lessee" hereunder (with a copy of such assumption provided to Lessor). Nothing contained in the Lease will be construed as creating a partnership, joint venture, association, trust, mining partnership, or other entity, whether for state law or federal income tax purposes.

10. The Lease contains other terms and provisions not herein set forth but incorporated by reference herein for all purposes. This Memorandum is executed for the purposes of placing all parties dealing with the Property, or with the improvements constructed on said Property, on notice of the existence of the referenced Lease and, where appropriate, its contents. This Memorandum does not modify the Lease. In the event of any conflict between the terms of this Memorandum and the Lease, the Lease shall control.

[SIGNATURE PAGE FOLLOWS]

EXECUTED this ____ day of March, 2022.

Given under my hand and Seal of Office

LESSOR	**LESSEE**
The State of Texas	**Bayou Bend CCS LLC**
By: ______________________________ Mark Havens	By: ____________________________________ Name: Tim Duncan Title: President and Chief Executive Office

Chief Clerk and Deputy Land Commissioner,
Texas General Land Office
On behalf of the Permanent School Fund

APPROVED:

Staff: _______________

Dir.: _______________

OGC: _______________

Exec.: _______________

STATE OF TEXAS §
§
COUNTY OF HARRIS §

This instrument was acknowledged before me on March ___, 2022, by Tim Duncan, President and Chief Executive Officer of Bayou Bend CCS LLC, a Delaware limited liability company, on behalf of said limited liability company.

____
Notary Public, State of Texas

EXHIBIT A
PROPERTY

All of Tract 5-S, Gulf of Mexico, Jefferson County, containing approximately 851.08 acres; and
All of Tract 6-S, Gulf of Mexico, Jefferson County, containing approximately 867.07 acres; and
All of Tract 7-S, Gulf of Mexico, Jefferson County, containing approximately 884.92 acres; and
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All of Tract 4-L, Gulf of Mexico, Jefferson County, containing approximately 5,761.59 acres; and
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E/2 of Tract 10-L, Gulf of Mexico, Jefferson County, containing approximately 2,880.45 acres; and
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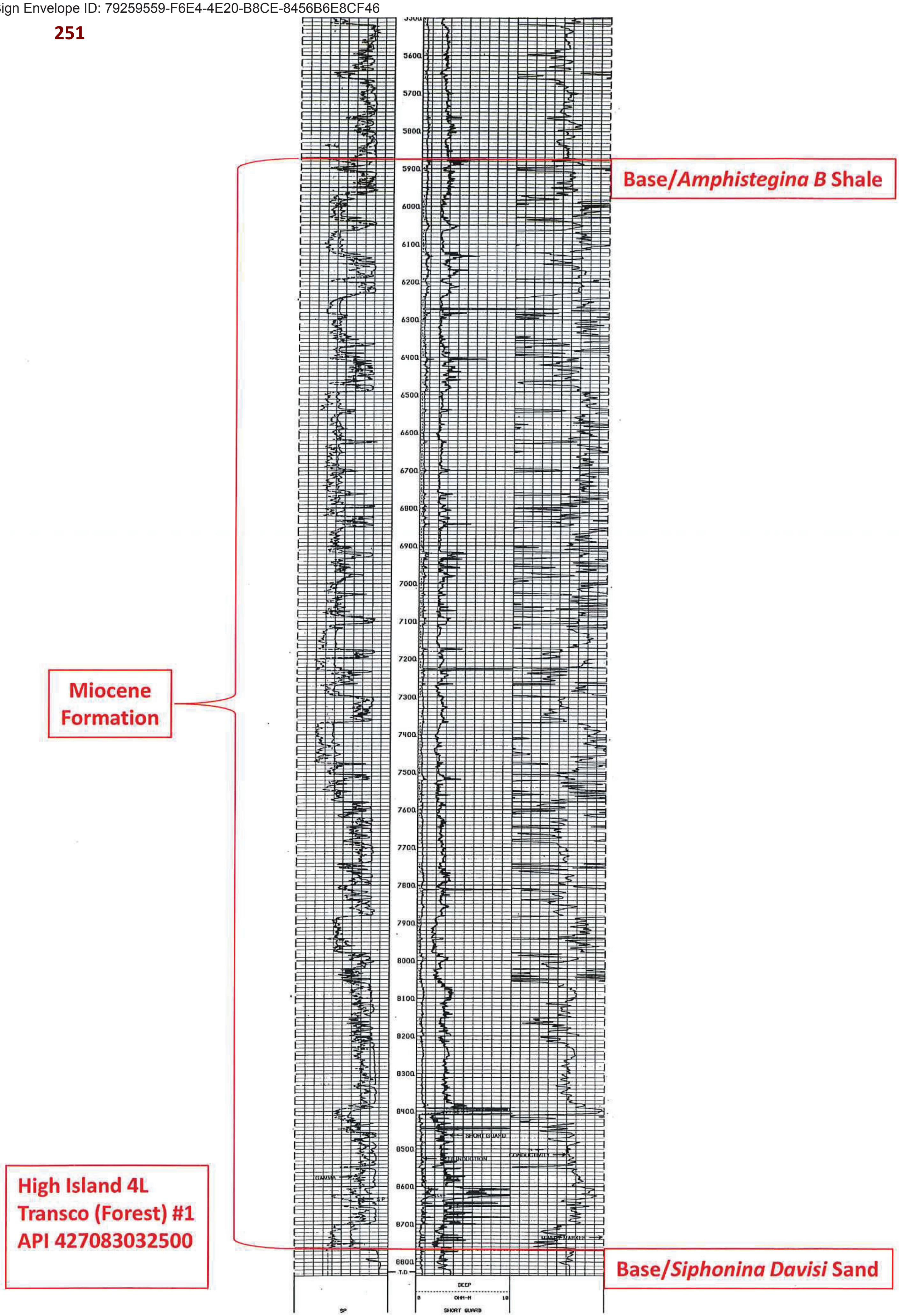
N/2 NW/4 and NE/4 of Tract 12-L, Gulf of Mexico, Jefferson County, containing approximately 2,160.62 acres; and
W/2 of Tract 13-L, Gulf of Mexico, Jefferson County, containing approximately 2,880.74 acres; and
N/2 NE/4 and N/348.6 of S/2 of NE/4 of Tract 21-L, north of Three Marine League line, Gulf of Mexico, Jefferson County, containing approximately 1,068.92 acres; and
N/2 NW/4 and N/374.14 of S/2 of NW/4 of Tract 20-L, north of Three Marine League line, Gulf of Mexico, Jefferson County, containing approximately 1,094.24 acres.

EXHIBIT C

Miocene Formation

See attached.



Base/*Amphistegina B* Shale
Miocene Formation
High Island 4L
Transco (Forest) #1
API 427083032500
Base/*Siphonina Davisi* Sand
5600
5700
5800
5900
6000
6100
6200
6300
6400
6500
6600
6700
6800
6900
7000
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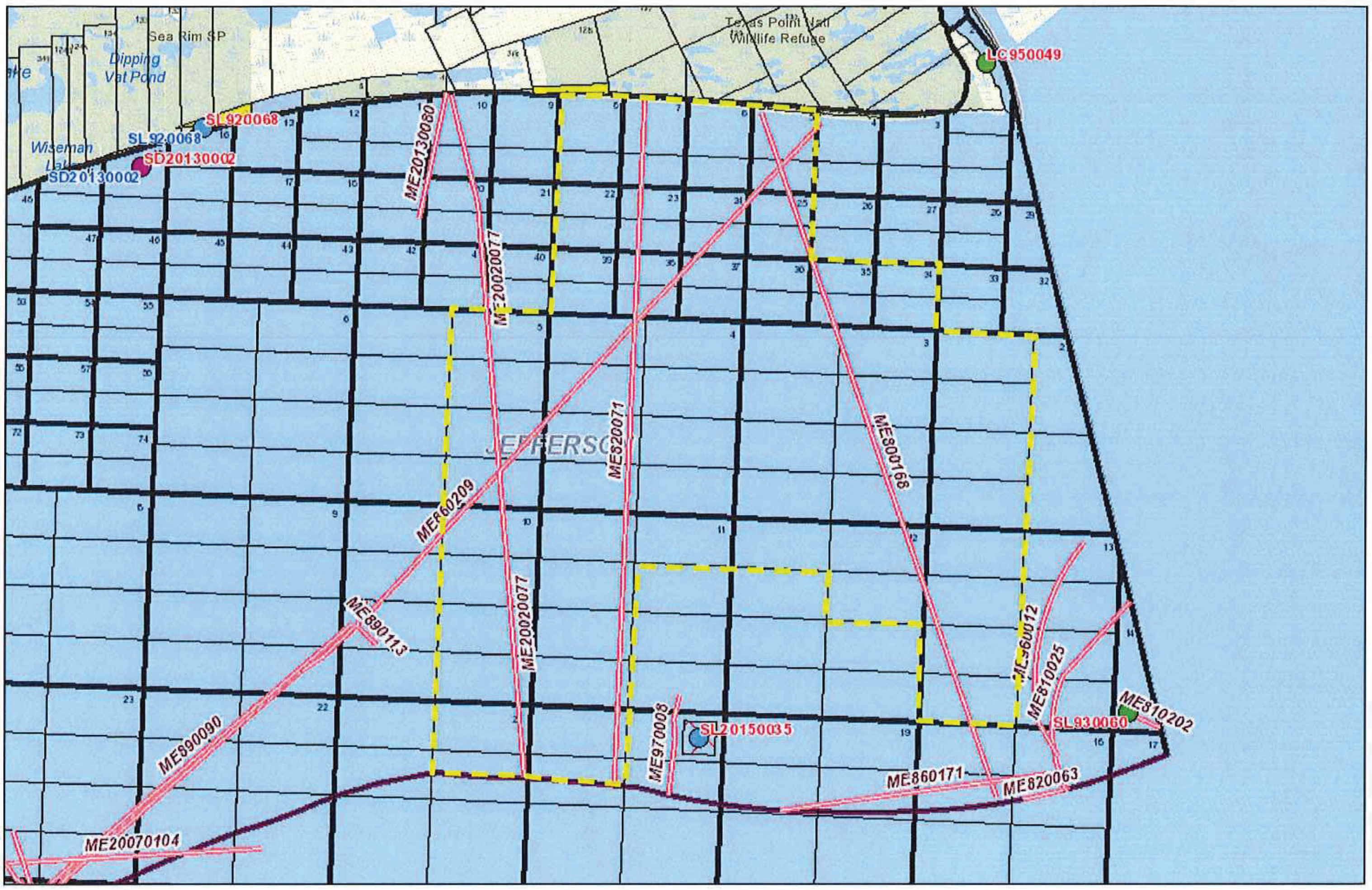
T.D.
SHORT GUARD
CONDUCTIVITY
GAMMA
DEEP
SP

Schedule 2.06

Authority of Lessor

GLO Lease No.	Description*
ME20020077	one (1) 24-inch O.D. pipeline for the purpose of transporting crude oil and other petroleum products
ME800168	one (1) 8.625-inch O.D. pipeline for the purpose of transporting crude oil
ME820071	one (1) 16-inch O.D. pipeline for the purpose of transporting natural gas
ME860209	one (1) 24-inch O.D. pipeline for the purpose of transporting natural gas and condensate

* more fully depicted in the attached graphics that follow



Active Leases within SL20220050 Lease Area

Please review all copyright and disclaimer information from our webpage here. https://www.glo.texas.gov/policy/index.html. The Texas General Land Office makes no representations or warranties regarding the accuracy or completeness of the information depicted on this map or the data from which it was produced. This map is not suitable for navigational purposes and does not purport to depict boundaries of private and public land.

Schedule 2.06

Page 2 of 3

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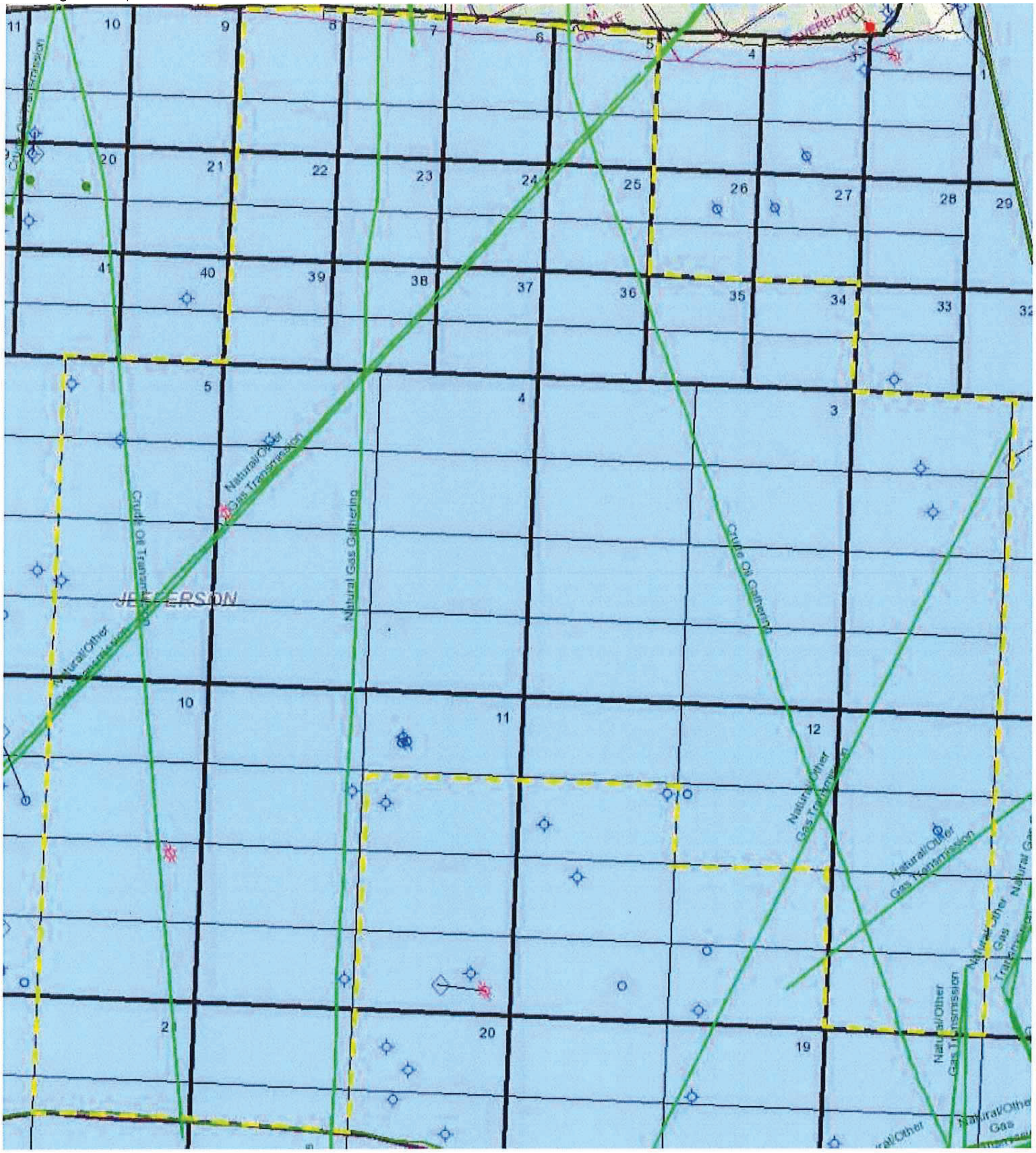
Print Date: 3/9/2022


JEFFERSON
Crude Oil Transmission
Natural/Other Gas Transmission
Natural Gas Gathering
Crude Oil Gathering
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OCC REGULATORY ROUNDTABLE: CURRENT ISSUES, HOT TAKES, AND MUSTANGS

Eric Huddleston,
Matt Allen,
and
Ben Brown

OCC Regulatory Roundtable: Current Issues, Hot Takes, and Musings

Benjamin J. Brown, Esq.
bbrown@charneybrown.com
(405) 330-0725
(918) 779-6047

Eric Huddleston, Esq.
ehuddleston@eliasbooks.com
(405) 232-3722

Matthew J. Allen, Esq.
Mallen@FoxRothschild.com
(405) 871-5580

CHARNEY BROWN LLC

ELIAS, BOOKS, BROWN & NELSON, P.C.

Fox Rothschild LLP
ATTORNEYS AT LAW

Toklan v. Citizen, 2022 OK CIV APP 37

- 1280-acre unit for Upper Meramec in 26 & 35-15N-16W, Custer County

- In February 2016, Citizen began discussions with Toklan re: development of the unit; no agreement reached

- *Prior to the drilling of the HZM Land 1H-35-26 well*, Toklan sells ORRI to Pescador LLC equal to 30% (less existing burdens)

Toklan v. Citizen, 2022 OK CIV APP 37

- Citizen drills the HZM Land 1H-35-26 well
  - Spud: October 26, 2018
  - Finished Drilling: January 19, 2019
  - Completion Date: February 18, 2019
  - First Production: March 15, 2019

- *After completion of the well*, Citizen files its pooling application

Toklan v. Citizen, 2022 OK CIV APP 37

- December 2019: Pooling hearing
  - Citizen asserted that Toklan and Custer Partners LLC, in contemplation of pooling, assigned ORRI to Pescador, burdening interest to 70% NRI
  - Citizen also claimed Toklan and Custer Partners LLC's interests were overburdened and not indicative of FMV
  - FMV testified to at hearing:
    - \$2,000 & 1/8th
    - \$1,500 & 16.5%
    - \$1000 & 3/16th
    - \$0 & 1/5th

Toklan v. Citizen, 2022 OK CIV APP 37

- December 2019: Pooling hearing
  - Evidence presented of only two transactions in the area with burdens as high as 30%.
    - Both involved Toklan, Custer, and Pescador
  - Citizen testified that “extensive negotiations to reach an agreement to develop the unit and drill a well prior to the assignment indicates the assignment [to Pescador] was made in an effort to circumvent the Commission pooling proceedings

Toklan v. Citizen, 2022 OK CIV APP 37

- December 2019: Pooling hearing

  - Result from pooling hearing: OCC found Toklan's overburden should be reduced from 30% to 20% to be more in line with arm's length FMV transactions in the area

  - Citizen testified that "extensive negotiations to reach an agreement to develop the unit and drill a well prior to the assignment indicates the assignment [to Pescador] was made in an effort to circumvent the Commission pooling proceedings

Toklan v. Citizen, 2022 OK CIV APP 37

- April 3, 2020: Toklan files written appeal of ALJ decision
- December 2020: hearing before Appellate Referee
  - ALJ affirmed by January 8, 2021 Report and Recommendation of the Referee
- Pooling Order 718145 issued May 4, 2021, affirming ALJ's and Referee's determinations regarding the FMV of Toklan's interest
- Toklan appealed

Toklan v. Citizen, 2022 OK CIV APP 37

- Two questions before the Court on appeal:

- 1. Is the Pooling Order, which modifies contractual rights relating to ORRI, outside of OCC's jurisdiction?

- 2. Is the Pooling Order too vague for judicial construction?

Toklan v. Citizen, 2022 OK CIV APP 37

- Answer to first question:
  - Parts of the Order which require Toklan (and parties not subject to the Order) to reduce the total burdens to 20% is outside of Commission's jurisdiction
    - Commission is a court of limited jurisdiction; powers granted by statute
    - "Commission does not have authority to alter ownership of royalty or to shift royalty away from the party taking the working interest pursuant to a pooling order."

Toklan v. Citizen, 2022 OK CIV APP 37

- Court relied upon *O'Neill v. American Quasar Petroleum Co.*, 1980 OK 2, 17 P2d 181:
  - "Commission is not clothed with authority…to enter an order…requiring the owner of an overriding royalty interest within a unit to elect between participation or acceptance of an alternative which disturbs the terms of the grant of the override."
  - In issuing pooling orders, Commission does not have the power to "reach for modification interests of those who are sans drilling rights *in praesenti*"
  - "…when an owner of a working interest elects not to participate in a unit well, electing rather to accept a bonus or royalty in lieu thereof, that working interest becomes the property of a person authorized to drill the well, and that unit operator is required to pay the bonus…[and] must stand the [] override obligations in the event [Appellant] does not participate"

Toklan v. Citizen, 2022 OK CIV APP 37

- "Unit operators must 'stand,' or pay, all of a pooled lessee's override obligations, despite the clear potential for abuse…"
- "…the Commission may not modify contractual rights relating to overriding royalty interests."
- "…whether the Commission ought to have that power is not for this Court to say but is best left to the legislative arena."

Toklan v. Citizen, 2022 OK CIV APP 37

- Answer to second question:
  - The Court remanded the matter back to the OCC, holding:
    - "…the Commission needs to reidentify the fair market value of [Toklan's] interest in light of O'Neill, which stands for the proposition that the unit operator, or [Citizen], must stand the overrides in the event [Toklan] does not participate."
    - "…the Commission failed to make specific findings and conclusions regarding how a reduction in the total royalty burdening [Toklan's] interest is to occur."

Toklan v. Citizen, 2022 OK CIV APP 37

- What happened after that? What is the status now?
  - The parties settled out of court
  - Toklan assigned its working interest to Citizen and lowered the ORRI (thus raising the NRI from 70% to 78%)
  - Assignment limited to zones in the Pooling Order for the life of the Pooling Order

Toklan v. Citizen, 2022 OK CIV APP 37

- What does this mean going forward?
  - Timing of grant of ORRI appears to be a substantial factor
  - Is this ripe for abuse?
  - Court implies that the Legislature must act if Commission is to have authority to decrease ORRI's to be more in line with FMV

Jones Energy, LLC v. Chisholm Oil and Gas Operating, LLC CD 2021-000704

- Jones Energy, LLC (“Jones”) filed the Application seeking to clarify Pooling Order No. 697058.
  - Sought declaration that the leasehold rights of a working interest owner in a pooled unit are relinquished to the Operator only upon payment in full of the prescribed bonus.
- Chisholm Oil and Gas Operating, LLC (“Chisholm”) sought to dismiss the case in its entirety.
- The Motion to Dismiss was argued on legal principles.
- No testimony was taken and no exhibits were offered or admitted.

Background

- Chisholm filed a Pooling Application to pool the Mississippian common source of supply underlying Section 36, Township 19 North, Range 9 West in Kingfisher County ("Section 36").
- The Pooling Order was issued on June 4, 2019. Jones was a respondent in the Application and Pooling Order.
- As of the issuance of the Pooling Order, Jones owned 160 leasehold acres in the unit.
- Jones elected to participate with one (1) leasehold acre. Jones elected to accept $2,200/acre and a royalty of 1/5 for the remaining 159 acres.
- Chisholm timely drilled and completed the Blacksmith 19-09-36 1MH well in Section 36.
- Beginning in March 2020, Chisholm issued checks to Jones for the 7.5% ORRI on the 159 acres and the working interest share of production on the 1 acre. Chisholm did not pay Jones the $2,200 per acre for the 159 acres.
- On June 17, 2020, Chisholm filed for bankruptcy. On August 21, 2020, Jones filed a proof of claim in the Chisholm bankruptcy for the cash pooling bonus.
- On September 8, 2020, Jones objected to Chisholm's proposed Plan of Reorganization asserting that Chisholm's rights and interests acquired under the Pooling Order do not vest until payment of the pooling bonus.
- On March 1, 2020, the Bankruptcy Court entered a Order confirming Jones' right to have the OCC interpret the Pooling Order and determine Chisholm's rights in the 159 acres.

Issue

When does a force pooled interest vest in the operator?

CHISHOLM: Rights vest when a respondent elects not to participate (or is deemed to have elected not to participate) once the election period expires.

JONES: When the respondent has been paid in full any cash bonus due under the pooling order.

Holding

- RECOMMENDATION: Chisholm’s Motion to Dismiss was granted.
- FINDING: At the time of the election or deemed election under the Pooling Order, rights vest in Chisholm, as the operator. The Oklahoma Corporation Commission (“OCC”) does not have jurisdiction over the payment of bonuses.

Scope of OCC's Authority

- The OCC only has authority and jurisdiction expressly conferred upon it by the Constitution and the statutes. *See Oklahoma City v. Corporation Commission*, 1921 OK 35, 195 P. 498.
- The OCC is commonly referred to as a tribunal of limited jurisdiction. *See Merritt v. Corporation Commission*, 1968 OK 19, 438 P.2d 495, 497.
- 52 O.S. § 87.1(e) limits the OCC's jurisdiction to determining just and reasonable terms and conditions as it pertains to owners of the tract. *See Amoco Prod. Co. v. Corp. Comm'n of Okla.*, 1986 OK CIV APP 16 at ¶16, 751 P.2d 203, 207.
- The OCC's authority regarding costs is limited to the cost of development and operation of the unit and the well.
- Once parties have made their elections or been deemed, the bonus amounts become a fixed obligation of the operator to pay.

Unpaid Cash Bonus is a Debt Owed

- The OCC has no jurisdiction to force an operator to pay a cash bonus.
- An unpaid cash bonus is considered a debt to be collected under the jurisdiction of the Oklahoma District Courts. *See* "Basic Information for the Oklahoma Royalty Owner, Last Revision - November 2020.
- Also see *Buttram Energies, Inc. v. Corporation Commission of State of Okla.*, 1981 OK 59, 629 P.2d 1252.
  - **The authority to determine whether the 1977 pooling order was still effective as to appellant's interest was incidental to the Commission's authority to determine whether or not appellant's application to re-pool should be approved or denied. The failure of Global Gas to make the in lieu payment within the time prescribed by the pooling order did not render the pooling order ineffective as to appellant's interest. Since appellant did not elect to participate, the obligation of Global Gas to pay the in lieu payment became fixed, and appellant was entitled to the in lieu payment whether Global Gas did or did not drill the unit well. Since the 1977 pooling order was still operative and there was no evidence submitted that would justify its modification, the commission's order is affirmed.**

Case Law

Amoco Prod. Co. v. Corp. Comm'n of Okla., 1986 OK CIV APP 16, 751 P.2d at 207:

- "once the spacing unit is pooled and the time for elections has past, the interest becomes vested and beyond the Corporation Commission's reach to modify."

TPR Mid-Continent, LLC, Case CD No. 201706298-OT and Case CD No. 201706300-OT:

- *The OCC fond that vesting of the working interest occurs upon election or deemed election of the Respondents.*
- *TPR filed motions to dismiss its pooling applications and pooling orders after lower and fluctuating commodity prices in an effort to avoid paying the required bonus payments.*
- *The OCC found nothing stayed the election period.*
- *The election period had run and vesting of the working interest occurred on election or deemed election of the respondents.*
- *No indication that the OCC retains jurisdiction over the actual payment of the bonuses.*

Legislative Support

- 52 O.S. § 549.1 *et seq.* – 2010 Oil and Gas Owners Lien Act
  - Amendment effective November 1, 2021
  - Supports the position that vesting of bonuses occurs at the election or deemed election.
  - Several members of the Oklahoma Energy Producers Alliance (“OEPA”) had experience of making non-participating elections under pooling orders with operators subsequently filing bankruptcy and the unpaid bonus being treated as an unsecured claim.
  - OEPA sponsored Oklahoma Senate Bill No. 632
    - Added three categories of proceeds to the lien covered by the 2010 Act, including pooling bonuses

Jurisdiction of the Commission vis-à-vis private contracts

The Basics

- The Commission is a tribunal of limited jurisdiction in conservation matters.
- The Commission's authority is derived from delegation of power by the Legislature.
- The Commission does not have the authority to interpret, alter or enforce private contracts.
- The Commission does not have robust authority to alter private property interests. (-Ish.)

Jurisdiction of the Commission vis-à-vis private contracts

A review of recent cases analyzing issues arising when provisions in private agreements conflict with Commission orders.

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

- Fast Facts
  - EnerVest was the operator under a number of pooling orders in Beckham County and nearby lands.
  - Mach acquired the position of EnerVest in the area, which included a significant number of acres of leasehold subject to both JOAs and pooling orders. Mach began operating the existing wells.
  - FourPoint succeeded to a position in the same area, also subject to the same JOAs and pooling orders.
  - FourPoint balloted non-operating WIOs under the JOAs to become the successor operator but did not include Mach. (Manner and method of balloting was a major point of contention.)
  - Litigation ensued in the District Court of Beckham County.
  - District Court gave initial ruling that balloting was proper and FourPoint ostensibly succeeded to operatorship under the JOAs.

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

- Fast Facts
  - FourPoint then sought declaratory judgment that FourPoint was the operator going forward.
  - However, as noted, JOAs covered leases within OCC drilling and spacing units that were also covered by pooling orders, which designated exclusive operators.
  - Mach filed numerous applications with the Commission to amend the pooling orders to change the operator thereunder to Mach.
  - Unbridled, successor to FourPoint, sought (a) to become operator of the wells, (b) to enjoin Mach from any further operations, and (c) contractual damages against Mach.
  - Unbridled protested the OCC applications, stating that the Commission did not have jurisdiction because the JOAs were private contracts that controlled operatorship and the OCC could not alter those agreements.
  - Mach filed motion to dismiss Unbridled’s claims.

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

- Trial court
  - GRANTED Mach's MTD as to declaratory and injunctive relief as to all pooled properties for a lack of SMJ.
  - DENIED Mach's MTD as to all claims relating to non-pooled properties.
- Unbridled appealed.

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

Main issue: whether the trial court had subject matter jurisdiction to determine the operator of units subject to force pooling orders of the Commission, even if there is a JOA in place with designated operator, where litigants are subject to both JOA and pooling orders.

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

Ruling: where there has been a forced pooling of interests pursuant to a Commission order, district courts cannot provide the relief Unbridled requested under the JOAs because the Commission has **exclusive** jurisdiction to designate an operator.

(Relying on *Crest Res. & Expl. Corp. v. Corp Comm'n*, 617 P.2d 215, 1980 OK 133.)

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

Further:

- Parties may freely contract as to interests created, duties defined, terms of participation and operations. Related disputes do belong in district court.
- However, parties may not redelegate by private agreement the Commission-conferred power to designate the unit operator. The district court did not have SMJ here.

(Again, relying on *Crest Res. & Expl. Corp. v. Corp Comm'n*, 617 P.2d 215, 1980 OK 133.)

Jurisdiction of the Commission vis-à-vis private contracts

FourPoint Energy, LLC v. BCE-Mach II, LLC, 503 P.3d 435, 2021 OK CIV APP 46.

Takeaways:

- The Commission's authority to designate an operator of wells and units under pooling orders does not yield to the provisions of the JOA setting forth the operator.
  - (Even in the face of this private agreement to the contrary.)
- Ruling couched in:
  - A lack of SMJ of the district court to attempt to designate the operator of wells or units subject to pooling orders.
  - The *Crest* case.

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

Fast Facts:

- MO grants OGL to Lessee, retaining a 1/4th RI.
- Lessee is force pooled by Operator. (Lessor is not subject to the pooling.)
- Operator errs in making payments to Lessor on the 1/4th RI.
- Operator finally pays Lessor in full but does not pay statutory interest under PRSA.

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

- Lessor brings several claims against Operator.
- Tort and PRSA claims are settled.
- Lessor continues to prosecute suit against Operator for breach of contract and for "improper cost deductions."

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

Let's think about what is happening:

- Lessor does not have direct contract with Operator.
- Lessee is out of the picture through the pooling order.
- Lessor sues Operator for obligations based in the OGL (a private contract).
- **Requested relief presumes that obligations under OGL "flow through" the pooling order and are imputed onto the Operator.**

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

Ruling:

- Operator is clearly not a signatory to the OGL.
- There is no other fact plausibly suggesting assignment of the OGL to the Operator, or assumption of obligations of the OGL by the Operator.
- **The court rejected Lessor's contention that, by reason of its status as operator, that Operator may be held liable for breach of contract claims.**

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

Ruling:

- Also disposed of “improper cost deduction” cause of action because that liability would generate from contractual obligations of Operator to Lessor.

Jurisdiction of the Commission vis-à-vis private contracts

Brown v. Newfield Exploration Mid-Continent, Inc., 2021 WL 1026526, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-19-600-G (Slip Copy 2021).

Takeaways:

- Other than RI payments, OGL obligations likely do not flow through pooling orders (?).
  - Bold statement!
- Again, private contract provisions hit a brick wall at the Commission and did not affect pooling order or operator's obligations in this case.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Fast facts:

- MO grants 80-acre OGL with fairly standard (and dated) voluntary pooling clause.
  - (Really, a voluntary "spacing" clause.)
- Lessee may contribute acreage into a voluntary unit, but only to an overall unit size of 160 acres.
- The Commission later formed a 640-acre horizontal well unit incorporating the lease acreage.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Fast facts:

- Operator drills a well in the 640-acre unit.
- Lessor sues Operator for breach of contract, conversation and declaratory judgment, **all predicated on allegation that Operator drilled the well in violation of the OGL's 160-acre voluntary pooling restriction.**

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Hot take: the voluntary pooling clause in an OGL is a fundamentally different concept than a statutory drilling and spacing unit formed by the Commission. The argument seems inapposite but the Court was still tasked with addressing it. (And address it, the Court did!)

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Holding: the Court rejected Lessor's argument.

Analysis:

- The Court focused on the intent of the parties to the OGL.
- The Court also reviewed *Hladik v. Lee*, 541 P.2d 196 (Okla. 1975), and *Okla. Nat. Gas Company v. Long*, 406 P.2d 499 (Okla. 1965).

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Hladik v. Lee, 541 P.2d 196 (Okla. 1975).

Holding: When a lessee pooled ten separate leases to create a 480-acre “declared” unit, and the Commission formed a 160-acre “compulsory” drilling and spacing unit within the same lands, only the owners within the 160-acre unit were entitled to share in production.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Hladik v. Lee, 541 P.2d 196 (Okla. 1975).

Reasoning: OGLs are negotiated against the backdrop of the Commission's authority, of which the parties are presumably aware. In absence of express agreement otherwise, it must be presumed that parties **intended** a valid exercise of OCC authority would supersede OGLs.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Okla. Nat. Gas Company v. Long, 406 P.2d 499 (Okla. 1965).

Holding: When an OGL requires production on the leased tract within a certain time period, or otherwise delay rentals are owed, and then the leased tract is incorporated into a Commission unit, and production is obtained outside the leased tract but within the unit, the OGL yields to the OCC order and the production satisfies the OGL.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Okla. Nat. Gas Company v. Long, 406 P.2d 499 (Okla. 1965).

Analysis: When the OGL was entered into, the parties knew of the authority of the Commission to create spacing units, and the parties contracted subject thereto.

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

BACK TO *CORY*:

- The Court held that *Hladik* and *Long* precluded Lessor's arguments here, with strong language.
- **"The OCC's regulatory authority, e.g., to space wells for conservation…is 'incorporated in[to]' private oil and gas leases by 'operation of law.'"**

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

BACK TO *CORY*:

- **"It is therefore the <u>expectation and intention</u> of the contracting parties that a valid exercise of the OCC's regulatory authority will supersede conflicting lease provisions of the kind at issue here."**
- **"[P]arties do not have carte blanche to enter into agreements that 'imping[e] upon the authority of the [OCC] to make orders establishing spacing and drilling units.'"**

Jurisdiction of the Commission vis-à-vis private contracts

Cory v. Cimarex Energy Company, 2021 WL 1108596, U.S. Dist. Ct., W.D. Oklahoma, Case No. CIV-20-706-G (Slip Copy 2021).

Takeaways:

- Private contracts cannot impinge the Commission’s authority to form spacing units.
- Further, a valid exercise of the Commission's authority in *any* conservation matter will supersede any conflicting provision in a private agreement.

Jurisdiction of the Commission vis-à-vis private contracts

Final thoughts:

- These cases are meant to highlight what appears to be a trend. (Please note two of the cases are not appellate cases.)
- The Commission's authority in relation to conflicting provisions in a private agreement appears to be quite robust.
- Compare and contrast this to the limitation of the Commission's authority in *Toklan*.

Questions?

LEASE EXPIRATION AND THE CESSATION OF PRODUCTION CLAUSE AFTER TRES C, LLC V. RAKER RESOURCES, LLC

Travis Brown,
Jeromy Brown,
Leah Rudnicki,
Kyle Domnick
and
Brad Welsh

Lease Expiration Landscape after Tres C. v. Raker Resources

Kuntz Conference 2023

Topics for Discussion

1. Obstruction Doctrine.
2. Lease Cancellation Post Tres C: "The Cessation of Production Doctrine" vs "The Cessation of Production Clause."
3. The role of "Capability of production" Post-Tres C Analysis for Catastrophic Failure vs Marginal Wells.
4. The Record on Appeal in an equitable lease cancelation case.
5. Lifting Costs with emphasis on "Low Volume Fees."

The Obstruction Doctrine

- "Where the lessee of an oil and gas mining lease is ready, willing and able to develop the premises and proceed with due diligence as required by the covenants contained in lease, an attack upon lessees' title by the lessor will relieve lessee of the duty to further proceed with drilling operations during the continuance of the attack, and the lessee is entitled to a reasonable time within which to proceed with drilling operations after the final disposal of the suit questioning title."

  - Jones v. Moore, 1959 OK 23, Syl. 1, 338 P.2d 872, 873.

What is an “attack upon lessees’ title”?

- “a communicated assertion that the lease is no longer valid and subsisting”
  - Hall v. Galmor (citing Allen v. Palmer, Elsey v. Wagner, Simons v. McDaniel)
- Demand letter to release lease was “sufficient attack” upon title to justify “desisting from further efforts to prosecute the drilling.”
  - Allen v. Palmer
- Execution of Top Lease “obstructed the exercise” of rights and clouded title.
  - Simons v. McDaniel

But see…

- “[E]ven the execution of a ‘top lease’ by a lessor does not affect the lessee's rights, or duties, under his prior lease in the absence of an attack upon his title.”
  - Moore Oil v. Snakard (W.D. Okla.)
- “[S]uch rule contemplates something more obstructive in the conduct of the lessor than mere notice by him to the lessee that, in the lessor's opinion, the lease has expired.”
  - Moore Oil v. Snakard (W.D. Okla.)
- Such notice “is not such a clear and unequivocal challenge that it constitutes obstruction."
  - 2 Kuntz, Law of Oil and Gas § 26.14

Who can invoke obstruction?

- In order for the obstruction to have such effect, the situation must be one where the lessee could otherwise have complied with the terms of the lease.
  - 2 Kuntz, Law of Oil and Gas § 26.14
- The "principle that all duties are suspended during litigation comes from cases which deal strictly with lessees who were sued <u>while in the process of drilling or reworking a well</u>."
  - Duerson v. Mills, 1982 OK CIV APP 14, ¶ 8, 648 P.2d 1276, 1278.

What about an already producing well?

- "There is a substantial distinction where the lease rights involve a producing well. Such a suit presents no compelling circumstances to excuse any of the lease terms."
  - Duerson v. Mills, 1982 OK CIV APP 14, ¶ 8, 648 P.2d 1276, 1278.

- Time that accrued after the filing of the petition in an action did not “constitute non-productive time for the purpose of this action since the filing of this proceeding puts the defendants' title at issue and relieves him of these covenants until determination is made that title to the lease does indeed rest with him.”
  - Hoyt v. Cont'l Oil Co., 1980 OK 1, ¶ 4, 606 P.2d 560, 562.

- “During the existence of such obstruction, it would be unreasonable to expect the lessee to make expenditures on a lease when to do so involves substantial risk of loss without a compensating prospect of gain.”
  - 2 Kuntz, Law of Oil and Gas § 26.14

Cessation of Production: Doctrine vs. Clause

"Under no circumstances will cessation of production ipso facto terminate a lease under its habendum clause."

- Stewart v. Amerada Hess Corp., 1979 OK 145, ¶ 11, 604 P.2d 854, 858.

Cessation of Production Doctrine

- The doctrine "provides that an oil and gas lease will remain valid during the secondary term as long as the cessation does not extend for a period longer than reasonable or justifiable under the circumstances."
  - Fisher v. Grace Petroleum Corp., 1991 OK CIV APP 112, ¶ 13, 830 P.2d 1380, 1386–87.

Cessation of Production Clause

- The effect of the cessation of production clause on a lease in its secondary term "is to modify the habendum clause and to extend or preserve the lease while the lessee resumes operations designed to restore production."
  - Hoyt v. Cont'l Oil Co., 1980 OK 1, ¶ 10, 606 P.2d 560, 563.

Before Tres C: Doctrine and Clause Interchangeable?

- "Where the law (by operation of the temporary cessation doctrine) would ordinarily give a lessee a "reasonable" amount of time in which to restore production, the cessation-of-production clause substitutes a bargained-for period of time that cannot be altered by any court's notion of reasonableness."
  - Hall v. Galmor, 2018 OK 59, ¶ 35

- "Where the parties have bargained for and agreed on a time period for a temporary cessation clause that provision will control over the common law doctrine of temporary cessation allowing a 'reasonable time' for resumption of drilling operations."
  - Hoyt v. Cont'l Oil Co., 1980 OK 1, ¶ 10

- The "contention that a 60-day cessation clause is time in addition to a reasonable time for resumption of drilling is not well taken in light of the express language of *Hoyt*."
  - French, 1986 OK 22, ¶ 7, 725 P.2d at 276-77

After Tres C: Different Purposes?

- The "cessation-of-production clause was never designed to eliminate or to avoid the operation of the temporary cessation doctrine."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 34.
- **Doctrine**: Only for "temporary cessations"?
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 34
- **Clause**: Becomes operative "only if the 'cessation' was permanent, as only a permanent cessation would require the remedy of drilling a new well."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 34.

The Role of "Capability of Production"

Production in Paying Quantities ("PPQ")

- "Produced," in the context of a habendum clause, means "produced in paying quantities," and "paying quantities" means an amount of production "sufficient to yield a profit to the lessee over operating expenses."
  - Hall v. Galmor, 2018 OK 59, ¶ 22.

Actual Production vs. Production in Paying Quantities

Capable of Actual Production only relevant with Shut-In Gas Wells?

- The Oklahoma Supreme Court described "capable of production in paying quantities" as "the characteristic that distinguishes a 'shut-in' well from a well experiencing a 'cessation of production.'"
  - Hall v. Galmor, 2018 OK 59, ¶ 21.
- A shut-in gas well will satisfy the habendum clause if it was capable of production when it was shut in.
  - Id. ¶ 26; Pack v. Santa Fe Minerals, 1994 OK 23, 869 P.2d 323, 326.

Production in Paying Quantities ("PPQ")

- This is the primary test in determining cessation of production.

Essential holding of Tres C:

- The three-month period of time used by the trial court is, "as a matter of law, too short for determining whether a cessation of **production in paying quantities** has occurred."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 26.
- Synonymous with "**Profitability**."
  - "Profitability" is used seven times in Tres C's analysis of the appropriate time period to measure PPQ. Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 30.

PPQ a prerequisite for the Cessation of Production Clause?

- "[N]either the cessation-of-production <u>clause</u> nor the temporary cessation <u>doctrine</u> have anything to do with the reasonable time period that governs the **<u>pre-cessation assessment of profitability</u>**."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 33.
- "First, we have repeatedly explained that the cessation-of-production clause is only implicated where *<u>production</u> has already ceased*—i.e., the clause only comes into play after a cessation has occurred."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 28.

Is the Tres C Opinion workable?

- "[W]hen an appellate court is reviewing whether the period employed by the trial court to determine profitability was sufficient, the appropriate time period is not measured in days, weeks or months, but by a time appropriate under all of the facts and circumstances of each case."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 30 (internal citations omitted).

- Catastrophic Failure
  - Clear point in time
  - Could "period employed by the trial court" be instantaneous?
  - "profitability" is not at issue
  - Is it capable of producing at all?

- Marginal Well
  - Reasonable look-back period makes sense
  - "profitability" is at issue
  - Is it capable of producing in paying quantities?

Life after Tres C:
Oil Valley Petroleum, LLC v. Moore, 2023 OK 90

- "In *Tres C, LLC v. Raker Resources*, LLC, 2023 OK 13, 532 P.3d 1, we discussed a time period over which *profitability* on an oil and gas lease should be determined."
  - Oil Valley Petroleum, LLC v. Moore, 2023 OK 90, ¶ 49.
- "We have explained a well's profitability is an element to a cause of action seeking to construe and apply the habendum clause in an oil and gas lease with an active well, and capability of profit for production is an element when construing a cessation of production clause with a shut-in well." (citing ***Hall v. Galmor***).
  - Oil Valley Petroleum, LLC v. Moore, 2023 OK 90, ¶ 49.

Record on Appeal

Standard of Review

- In an equitable proceeding the findings of the trial court will not be set aside unless it appears that such findings are clearly against the weight of the evidence.
  - Hall v. Galmor, 2018 OK 59, ¶ 12.
- This is because the trial court "is better able to determine a controverted issue of fact than is this court, which, of necessity, is permitted only to consider the dry, printed words appearing in the record."
  - Perry v. Perry, 1965 OK 160, ¶ 5.

Did the *Tres C* Court make factual findings?

- "The evidence presented and relied upon by the trial court established that the Cowan Well was not producing in paying quantities for a period of three months, ***but three months is not an appropriate time period under all of the facts and circumstances of this case***, particularly in light of the operator's efforts to remedy the dip in production."
- Thus, "judgment should have been entered in favor of Defendants/Petitioners ***by reason of Plaintiff's failure to carry their burden of proof***."
- "We hereby quiet title in favor of Defendants."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 37.

Or was it a legal holding?

- The issue before this Court is whether it was **legal error** for the trial court to apply a **rule of law** that analyzed only a 3-month window of time for assessing whether the Cowan Well had experienced a cessation of production in paying quantities such that the Cowan Lease expired by its own terms.
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 23.
- The three-month "period of time is, ***as a matter of law***, too short for determining whether a cessation of production in paying quantities has occurred."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 26

Was the factual determination raised?

- The failure to raise an error for appeal by inclusion in the petition in error is fatal to its consideration.
  - Timmons v. Royal Globe Ins. Co., 1982 OK 97, ¶ 13; Markwell v. Whinery's Real Est., Inc., 1994 OK 24, ¶ 8.
- Issues resolved by COCA but not explicitly re-pressed for certiorari review are deemed abandoned and beyond this court's cognizance for corrective relief.
  - Walters v. J.C. Penney Co., 2003 OK 100, ¶ 6.

Can the Supreme Court rule against an appellant for not carrying their burden of proof as it relates to a law the Court just laid down?

- "By reason of Plaintiff's ***failure to carry their burden of proof***. … We hereby quiet title in favor of Defendants."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 37 (emphasis added).
- The burden would be to show that the Cowan Well was not producing in paying quantities for ***an appropriate time period under all of the facts and circumstances of this case.***
  - "The evidence presented and relied upon by the trial court established that the Cowan Well was not producing in paying quantities **for a period of three months**." *Id*.
  - The appropriate time period was never determined.
  - Tres C Court only says it can't be three months.

Are the parties charged with knowledge of law that is yet to be clarified by the Court?

- In other words, was Tres C supposed to produce evidence at trial that conformed to the law according to the *Tres C* Court?
- "It is the general rule that neither ignorance, mistake, nor the misapprehension of an attorney not occasioned by the adverse party, is any ground for vacating a judgment or granting a new trial."
  - Bd. of Comm'rs of Oklahoma Cnty. v. Barber Asphalt Paving Co., 1921 OK 327.
- "When a judgment or final order shall be reversed on appeal, either in whole or in part, the court reversing the same shall proceed to render such judgment ***as the court below <u>should have rendered</u>***."
  - 12 O.S. § 975 (emphasis added).

Lifting Costs Defined

- Production in paying quantities "means that the lessee must produce in quantities sufficient to yield a return, however small, in excess of '**lifting expenses**.'"
  - Stewart v. Amerada Hess Corp., 1979 OK 145, ¶ 5.
- Lifting costs are "only those expenses which are directly related to lifting or producing operations can be offset against production proceeds to determine whether a well is a producer."
  - Mason v. Ladd Petroleum, 1981 OK 73, ¶ 5.

What do lifting costs include?

- "The term 'lifting costs' relates to a portion of the cost of producing oil and gas exclusive of drilling and equipping costs."
  - Hininger v. Kaiser, 1987 OK 26, ¶ 6.
- They cannot be "too indirectly and too remotely related to defendant's lifting or producing operations."
  - Mason v. Ladd Petroleum, 1981 OK 73, ¶ 7.
- **Not included**: district expenses of oil and gas lessee, administrative overhead, depreciation of casing, tubing, and Christmas tree, and depreciation of a line heater and low-pressure separator.
  - Mason v. Ladd Petroleum, 1981 OK 73.

Lifting Costs and Low Volume Fees

- "The trial court found that the costs associated with **installation of the compressor** on the Cowan Well were **lifting costs** and that the **low volume fees charged by the gas purchaser** were **to be deducted from gross revenue** in determining whether the well produces in paying quantities, but the trial court found the insurance expenses on the Cowan Well were not lifting costs."
  - Tres C, LLC v. Raker Res., LLC, 2023 OK 13, ¶ 18 (cleaned up) (emphasis added).