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ALABAMA

Edward "Ted" Holt, George Hayek, and Brandt Hill

I. CASE LAW

A. *State Courts*

1. Ex parte Alabama Surface Mining Commission

This case reviewed and conclusively determined the proper venue in which to file appeals from decisions by the Alabama Surface Mining Commission (the "Commission"). The Commission issued a surface-coal-mining permit to Black Warrior Minerals, Inc. ("Black Warrior"), allowing Black Warrior to mine land in northern Jefferson County, Alabama.[1] In response, three. individuals who owned property nearby appealed the permit's issuance with the Commission's Department of Hearings and Appeals, and a hearing

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1. *Ex parte* Ala. Surface Mining Comm'n v. *Ex parte* Black Warrior Minerals, Inc., No. 1170222, 2019 WL 168405 at *1 (Ala. Jan. 11, 2019).

officer affirmed the issuance.[2]. The property owners then petitioned the Commission for review of the officer's decision, but their petition was never taken up and thus was denied by operation of law.[3].

With no remaining alternatives, the property owners sought judicial review of the Commission's decision, opting to file their suit in the Circuit Court for Jefferson County (home to the subject property) rather than in the Circuit Court for Walker County (the Commission's headquarters).[4]. In response, the Commission and Black Warrior each moved to dismiss the case or, alternatively, transfer the appeal to the Walker County Circuit Court.[5]. The Jefferson County Circuit Court denied both motions, prompting Black Warrior and the Commission to petition the Alabama Court of Civil Appeals for writs of mandamus, specifically on the issue of venue.[6]. However, the Court of Civil Appeals denied those petitions.[7]. With the tables now turned, Black Warrior and the Commission petitioned the Supreme Court of Alabama, hoping to finally have the matter transferred to Walker County.[8].

The Supreme Court began its analysis by discussing the contours of the Federal Surface Mining Act and its interplay with Alabama's own iteration of this regulatory framework.[9]. On its passage in 1981, the Alabama Surface Mining Act ("ASMA") allowed parties to seek judicial review of Commission decisions but, critically, the ASMA prescribed no specific venue to bring these lawsuits, leaving the issue to the courts.[10]. As a result, various parties over the years litigated the venue issue until, in 2015, the Alabama legislature amended the ASMA to clarify that the only proper venue for judicial review of Commission decisions is "in the circuit court of the county in which the commission maintains its principal office"—in other words, Walker County.[11].

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2. *Id.*
3. *Id.*
4. *Id.*
5. *Id.*
6. *Id.*
7. *Ex parte* Ala. Surface Mining Comm'n v. *Ex parte* Black Warrior Minerals, Inc., 254 So.3d 904 (Ala. Civ. App. 2017), *rev'd*, 2019 WL 168405 (Ala. Jan. 11, 2019).
8. *Ala. Surface Mining Comm'n*, 2019 WL 168405, at *1.
9. *Id.* at *1–2.
10. *Id.* at *3.
11. *Id.* at *4 (quoting ALA. CODE § 9-16-79(4)b).

However, this 2015 amendment did not resolve the venue issue entirely. The property owners argued that at the time they filed suit in Jefferson County Circuit Court in January 2017, the amendment was not yet effective.[12]. The Federal Surface Mining Act provides that any "change to laws or regulations that make up the approved State [surface mining regulatory] program" must be approved by the Office of Surface Mining Reclamation and Enforcement (the "OSM") before taking effect.[13]. Seizing on this language, the property owners argued that because the 2015 amendment to the ASMA had not yet been approved by the OSM when they sued in January 2017, its venue provision was not yet effective—and thus Jefferson County was a proper venue.[14].

In response, the Commission and Black Warrior argued that the 2015 amendment did not require OSM approval because it did not constitute a "change to laws or regulations" to Alabama's regulatory program; it merely prescribed the proper venue and does not address the regulation of mining itself.[15]. In a 5-3 split, a majority of the Supreme Court of Alabama agreed.

Specifically, the court found that the Federal Surface Mining Act only required states to provide a "court of competent jurisdiction" to adjudicate appeals; it did not require states to include a particular venue provision.[16]. The court further noted that when the ASMA was originally enacted, it did not include a venue provision but was still approved by the OSM. Thus, the 2015 amendment "did not alter Alabama's state program and did not require the approval of the

12. *Id.*
13. *Id.*
14. *Id.* The property owners' argument that Jefferson County was a proper venue relied on the Alabama Administrative Procedures Act, which was enacted in 1982, just one year after the ASMA. *See* ALA. CODE § 41-22-27. Among other things, the AAPA detailed "the procedure for soliciting judicial review of final decisions of administrative agencies within the State." *Ex parte* Worley v. Worley, 46 So.3d 916, 919 (Ala. 2009). It specifically provided that venue for such judicial proceedings is proper "either in the Circuit Court of Montgomery County or in the circuit court of the county in which the agency maintains its headquarters, or unless otherwise specifically provided by statute, in the circuit court of the county where a party . . . resides." ALA. CODE § 41-22-20(b) (1975). Because the pre-amendment version of the ASMA did not contain a specific venue provision, and because its 2015 amendment was not yet effective, the property owners argued that venue was proper in Jefferson County under the AAPA
15. *Ala. Surface Mining Comm'n*, 2019 WL 168405, at *5.
16. *Id.*

OSM," meaning the venue provision became valid on its effective date in June 2016—before the property owners filed suit.[17]. Accordingly, the Supreme Court held that the Commission and Black Warrior "have demonstrated a clear legal right to have the underlying action transferred to the Walker Circuit Court."[18].

Justices Shaw, Parker, and Bryan dissented.[19]. In Justice Shaw's dissent (which Justice Bryan joined), he noted: "It is clear that the 2015 amendment itself is part of the state program, despite the fact that it does not directly regulate mining operations."[20]. Specifically, he observed that the 2015 amendment's venue provision affects the judicial procedures and remedies involved with challenging the Commission's decisions, which are federally mandated aspects of the state program, "despite the fact that those procedures may not directly impact mining operations."[21]. Furthermore, Justice Shaw observed that the Commission itself believed the 2015 amendment was a change to Alabama's state program, as evidenced by the agency's explicit characterization of it as such.[22]. Since the provision constituted a change to the state program, it needed to be approved by the OSM before becoming valid, which never occurred.[23]. Accordingly, Justice Shaw concluded that "the 2015 amendment was not in effect when the underlying administrative appeal was commenced and did not control venue in this case."[24].

17. *Id.*
18. *Id.*
19. *Id.*
20. *Id.* at *10 (Shaw, J., dissenting).
21. *Id.*
22. *Id.* at *11 (Shaw, J., dissenting).
23. *Id.*
24. *Id*.

ALASKA

George R. Lyle, Adam D. Harki, and Traci N. Bunkers[1]

I. LEGISLATION

The First Regular Session of the thirty-first Alaska Legislature began on January 15, 2019, and ended on May 15, 2019. A First Special Session was held from May 16, 2019, through June 13, 2019, with a Second Special Session following from July 8, 2019, through August 6, 2019.

The 2019 legislative session resulted in virtually no oil and gas legislation being passed, as the Alaska Legislature focused primarily on legislation regarding the State budget and the funding of the Permanent Fund Dividend. Despite the uncharacteristic lack of oil and gas legislation, the Legislature addressed the prevalent issue of oil and gas leasing in the Arctic National Wildlife Refuge ("ANWR") through the passage of Senate Joint Resolution No. 7.

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A. Senate Joint Resolution No. 7 ("SJR 7")

In passing SJR 7, the Legislature resolved to request that the United States Department of the Interior, Bureau of Land Management ("BLM") implement an oil and gas leasing program in the coastal plain of the ANWR.

The Resolution provides that 16 U.S.C. 3143 (sec. 1003 of the Alaska National Interest Lands Conservation Act ("ANILCA")) and 16 U.S.C. 3142 (sec. 1002 of ANILCA) authorize both oil and gas development and production and nondrilling exploratory activity within the coastal plain of the ANWR.[2] In passing the SJR 7, the Legislature noted that the coastal plain of ANWR contains an estimated 7.687 billion barrels of recoverable oil and 7 trillion cubic feet of natural gas,[3] which could generate over $104 billion in government revenue from petroleum development.[4] SJR 7 further notes that exploration, development, and production of ANWR is predicted to generate 1,430 direct and 6,350 indirect jobs annually, with 2,480 direct and 10,100 indirect jobs at peak employment.[5]

The Resolution closes with the Legislature's request that the BLM take into consideration "the long history of safe and responsible oil and gas development on Alaska's North Slope, the enormous benefits development of oil and gas resources in the coastal plain of the ANWR would bring to the state and the nation, the advances in oilfield technology that continue to shrink the impact area of oil and gas activities, and the support of residents from the North Slope Borough and across the North Slope of Alaska for oil and gas development in a portion of the coastal plain."[6]

II. CASE LAW

A. Cases of the Supreme Court of Alaska

i. *All American Oilfield, LLC v. Cook Inlet Energy, LLC*[7]

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2. SJR 7, p.1.
3. *Id.*, p. 2.
4. *Id.*
5. *Id.*
6. *Id.*, p. 3.
7. *All Am. Oilfield, LLC v. Cook Inlet Energy, LLC*, 446 P.3d 767 (Alaska 2019).

In 1910, the United States Congress passed Alaska's first mineral dump lien statute, which grants laborers a lien against a "dump or mass" of hard-rock minerals for their work creating the dump. Alaska's territorial legislature amended the dump lien statute in 1933 to include oil and gas development. This amendment has created the framework for technological advances in Alaska's oil and gas industries that has remained largely unchanged.

In *All American Oilfield LLC*, the Alaska Supreme Court accepted certified questions from both the United States District Court and the United States Bankruptcy Court[8] regarding the breadth of the mineral dump lien statute as it applies to natural gas development:

1. Can a "dump lien" under Alaska Statute ("AS") 34.35.125 *et seq*. apply to gas stored in its natural reservoir?;
2. Is a mineral "dump" created under AS 34.35.140 and AS 34.35.170(a)(1) each time that natural gas is released from the natural reservoir in which the gas was formed and transported through a pipeline to the point of sale?
3. Must a dump lien claimant under AS 34.35.140 prove, in order to have a valid dump lien, that the produced gas was, in whole or in part, the product of her labor?[9]

a) Un-Extracted Natural Gas Remaining In Its Natural Reservoir Cannot Constitute A "Dump"

With respect to the first question, the Supreme Court held that the statutory definition of "dump or mass" reflects that a mineral dump lien may extend only to gas extracted from its natural reservoir.[10] Under the relevant statutory framework, there must be a

8. The certified questions stem from an adversary proceeding filed by All American in case of *In re Cook Inlet Energy LLC*, 2017 WL 1082217 (Bankr. D. Alaska Mar. 21, 2017), in which All American asked the bankruptcy court to determine the validity and priority of its secured claims against Cook Inlet, as well as a district court case in which the trustee for Cook Inlet's liquidation trust sued Carol Inman, d/b/a Starichkof Enterprises for payments that Cook Inlet made to her prior to filing for bankruptcy. *See All Am. Oilfield, LLC*, 446 P.3d at 770.

9. *All Am. Oilfield, LLC*, 446 P.3d at 771.

10. *Id*., at 773.

"dump" to which the lien can attach for a claimant to obtain a dump lien.[11]

The Court found that the existence of a dump is a condition precedent to obtaining a dump lien. Under the statute's plain meaning, un-extracted gas cannot constitute a dump because it was never "extracted, hoisted, and raised" as the statutory definition requires.[12]

The Supreme Court further found that neither the legislative history nor the relevant case law interpreting the dump lien statute extends the statutory definition of "dump" to include any un-extracted gas remaining in its natural reservoir.[13] Further, affording the statute its plain meaning does not lead to glaringly absurd results.[14]

b) Natural Gas in a Pipeline May Constitute a "Dump"

In ruling on the second certified question, the Supreme Court found that, because gas in a pipeline has been "extracted, hoisted, and raised" and is "in mass," it may constitute a dump if it is located "adjacent" to the mine or mining claim. However, whether gas is adjacent to a mine or mining claim must be decided on a case-by-case basis.[15]

The Court rejected Cook Inlet's arguments that gas in a pipeline cannot qualify as a "dump." Instead, the Court determined that gas in a pipeline has been "extracted, hoisted, and raised"

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11. *See* AS 34.35.140(a).

12. *All Am. Oilfield, LLC*, 446 P.3d at 773. *See* AS 34.35.170(a)(1).

13. *All Am. Oilfield, LLC*, 446 P.3d at 774, *examining* Act of June 25, 1910, ch. 422, (creating miner's labor lien in Alaska territory); 45 Cong. Rec. 4,905 (1910); *Donaldson v. Henning*, 4 Alaska 642 (D. Alaska 1913); *Nordstrom v. Sivertsen-Johnsen Mining & Dredging Co.*, 5 Alaska 204 (D. Alaska 1914); Ch. 79, SLA 1913; Ch. 13, SLA 1915; Ch. 113, SLA 1933.

14. *All Am. Oilfield, LLC*, 446 P.3d at 776. In ruling "no" to the first certified question, the Supreme Court held that All American could not qualify for a dump lien under AS 34.35.140 because the gas for which All American drilled wells was not "extracted, hoisted, and raised" from the mine. However, the Court noted that All American may still obtain a non-preferred mine lien under AS 34.35.125, as the definition of "mine" or "mining claim" includes "all valuable mineral deposits, including coal, oil, gas, or other fluid, and all loads, veins, or rock in place containing minerals." *See* AS 34.35.170(a)(3).

15. *All Am. Oilfield, LLC*, 446 P.3d at 777.

because it has been "extracted from the soil and brought to the surface," and, thus, ceases to be a mineral deposit.[16]

Alaska Statute 34.35.170(a)(1) also requires gas to be "in mass" to constitute a dump. The statute provides that a dump is "in mass . . . whether it is deposited in dumps or piles, or placed in hoppers, tanks, or reservoirs, or in sluice boxes or bunkers or other receptacles."[17] Adopting the interpretation that the "whether" clause of the statute limits the ways that a dump can be "in mass" to the enumerated examples,[18] the Court noted that the only way for natural gas to be "in mass" would be for it either to be "deposited in dumps or piles" or "placed in hoppers, tanks, or reservoirs, or in sluice boxes or bunkers or other receptacles."[19] However, because gas cannot be deposited into a dump or pile, the determination rests on whether natural gas pumped out of its natural reservoir into a pipeline on its way to another destination is "placed" into a "receptacle" for the statute's purposes.[20]

The Court examined the definitions of receptacle, tank, and hopper, and concluded that pipelines constitute "receptacles." Even though the primary purpose of a pipeline is transport, the statute's inclusion of "sluice box" indicates that a "receptacle" under the statute need not only or primarily hold its contents.[21] Thus, "[i]n the process of conveying a gas, pipelines do hold or contain it for a brief period of time, as a receptacle would."[22] However, whether gas in a pipeline is "adjacent" to a mine or mining claim, in order to constitute a dump, requires a "fact-specific inquiry to determine if

16. *Id.*, at 778, citing 38 Am. Jur. 2d *Gas and Oil* § 4 (2017) ("Gas and oil when unsevered are a part of the land and after gas and oil are extracted from the soil and brought to the surface, they are deemed personal property." (Internal citations omitted)); *see Cont'l Res. of Ill., Inc. v. Ill. Methane, LLC*, 847 N.E.2d 897, 901 (Ill. App. 2006) ("Oil and gas in place are minerals, but because of their fugacious qualities, they are incapable of ownership distinct from the soil. . . . Oil and gas are incapable of ownership until actually found and produced.").

17. *All Am. Oilfield, LLC*, 446 P.3d at 778, citing AS 34.35.170(a)(1).

18. *All Am. Oilfield, LLC*, 446 P.3d at 778, citing *Studdert v. Tanana Valley Gold Dredging Co.*, 8 Alaska 267, 271 (D. Alaska 1931) ("Clearly, in my judgment, the Legislature intended, by the use of this language, to refer only to sands, earth, ore, rock, and minerals which were either deposited in dumps or piles, placed in hoppers or tanks or in sluice boxes or bunkers, or other receptacles, located in the same place.")

19. *All Am. Oilfield, LLC*, 446 P.3d at 778.

20. *Id*.

21. *All Am. Oilfield, LLC*, 446 P.3d at 779.

22. *Id*.

the off-mine portions are close enough to be considered 'adjacent' to the mine."[23]

c) Produced Gas Must be the Product of the Lienor's Labor

The Supreme Court answered the final question, whether dump lien claimants must prove that produced gas is the product of their labor, in the affirmative. Unlike AS 34.25.125, AS 34.35.140(a) plainly requires that lien claimants make this showing, providing that the dump lien is "to secure the amount due the laborer in the production of the minerals."[24] The Supreme Court found that a laborer may claim and enforce a dump lien by performing any of the kinds of work mentioned in the dump and mine lien statutes;[25] however, whether a particular claimant's labor meets these requirements is case-specific and must be left to the trier of fact.[26]

ii. *Kenai Landing, Inc. v. Cook Inlet Natural Gas Storage Alaska, LLC*[27]

In *Kenai Landing, Inc.*, the Supreme Court affirmed the Superior Court's ruling regarding compensation for producible native gas remaining in a reservoir at the time of a taking, as well as its valuation of gas storage rights.

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23. *Id*. at 780. The Supreme Court made no rulings with respect to whether the gas in the pipelines was "adjacent" with respect to All American's and Inman's claims, as neither the bankruptcy court nor the district court made findings about the exact location and size of the pipelines at issue in those cases. *Id*.

24. AS 34.35.140(a).

25. *See* AS 34.35.140(a) (a claimant may be entitled to a dump lien by performing "any of the kinds of work mentioned in AS 34.35.125" or "any other kind of work in the production, piling up, or storing of a dump or mass of mineral.") *See also* AS 34.35.12 (identifying the following work entitling a claimant to a mine lien: opening up, developing, sinking, drilling, drifting, stoping, mucking, stripping, shoveling, mining, hoisting, firing, cooking, teaming, or perform[ing] any other class or kind of work necessary or convenient to the development, operation, working, or mining of the claim or well; . . . perform[ing] work tending to or assisting in the developing, extraction, separation, or reduction to a commercial value of the minerals; . . . perform[ing] work on a water right, ditch, flume, pipe line, tramway, tram, road, or trail, used in connection with the opening up, or to facilitate the opening up, operation, or development of the claim or well, or the extraction of the minerals.)

26. *All Am. Oilfield, LLC*, 446 P.3d at 781.

27. 441 P.3d 954 (Alaska 2019).

a) Background

The appellee, Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"), is a private company that was building a natural gas facility for storage of natural gas collected from various sites. The gas is stored by injecting it into a rock formation, known as the Sterling C Reservoir.[28] To facilitate efficient gas extraction, there must be a minimum amount of pressurization, which requires a minimum amount of gas in storage, also known as "base" or "cushion" gas.[29] Within the Sterling C Reservoir, some of the base gas consisted of gas left in the Reservoir when it was acquired by CINGSA.[30]

The appellant, Kenai Landing, Inc., owns a parcel of land overlying the Sterling C Reservoir that was acquired subject to the Wards Cove Lease (the "Lease"). The Lease is committed to the Cannery Loop Unit and exists so long as gas is being produced anywhere in the unit.[31]

To operate its storage facility, CINGSA filed a condemnation action to obtain necessary property rights. At the time of filing the action, the royalty rights under the Lease were held by Wards Cove, and the production rights were held by Marathon Alaska Production Company.[32] CINGSA negotiated separate agreements with both Wards Cove and Marathon to obtain their rights as lessor and lessee, respectively, under the Lease. The Department of Natural Resources subsequently agreed to sever the Sterling C Reservoir from the Cannery Loop Unit so that it could be used for storage purposes.[33] After CINGSA commenced its condemnation proceeding, it discovered a "pocket of gas," which ultimately increased the amount of native gas in the Reservoir, including the gas underneath Kenai Landing's property.[34]

b) Procedural History

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28. *Kenai Landing, LLC*, 441 P.3d at 957.
29. *Id*.
30. Gas left in the ground is known as "native gas."
31. *Kenai Landing, LLC*, 441 P.3d at 957-58.
32. *Id*. at 958.
33. *Id*.
34. *Id*.

CINGSA subsequently filed a complaint against Kenai Landing to condemn certain rights to the Sterling C Reservoir that it had not already acquired, including: (1) an easement for gas storage, including any underground formations in the Reservoir, as well as an adjoining geological zone for use as a "buffer;" and (2) an easement in the mineral interests, allowing CINGSA the use of "all gas, oil, or other minerals . . . located within the Sterling C Pool and the correlative buffer geological formation, including the use of native gas as base gas for the storage facility."[35]

CINGSA subsequently moved for partial summary judgment on the grounds that Kenai Landing had no right to compensation for any of the native gas in the Reservoir because CINGSA owned this gas as assignee of the Lease. Finding that the Lease was still in effect, the superior court found that Kenai Landing was not entitled to compensation for native gas and granted summary judgment in CINGSA's favor.[36]

Because the parties agreed that Kenai Landing was entitled to compensation for the use of its property for underground gas storage, the superior court held a hearing to value the storage rights and corresponding valuation. Kenai Landing disputed the superior court's valuation and subsequently filed an appeal, in which it: (1) challenged the superior court's refusal to compensate it for CINGSA's use of native gas; (2) argued that it was entitled to compensation for the "new" gas discovered by CINGSA after the taking; and (3) disputed the valuation of its storage rights.[37]

c) Kenai Landing Was Not Entitled to Compensation for Native Gas

The Supreme Court agreed with the lower court that Kenai Landing was owed no compensation for the producible native gas remaining in the Sterling C Reservoir at the time of the taking. Analyzing the principles of just compensation, the Court determined that Kenai Landing lost nothing by virtue of CINGSA's condemnation of an easement.[38] Specifically, because CINGSA holds both production rights and a royalty interest by virtue of its assignment under the Wards Cove Lease, Kenai Landing does not

35. *Id*.
36. *Kenai Landing, LLC*, 441 P.3d at 958.
37. *Id*. at 959.
38. *Id*. at 960.

have the right to produce or receive royalties so long as the Lease exists.[39] CINGSA, "by condemning the easement, gained the use of the native gas as base gas, but Kenai Landing did not lose anything it already had."[40]

The Supreme Court characterized Kenai Landing's right to the gas as reversionary because it had no right to extract native gas, block its production, or use the native gas for any purpose. As such, Kenai Landing was not entitled to compensation for any producible native gas that remained in the Reservoir at the time of the taking.[41]

d) Kenai Landing Was Not Entitled to Compensation for New Gas

Kenai Landing's second argument, that it was entitled to compensation for newly discovered gas, was rendered moot by the Supreme Court's ruling that Kenai Landing was not entitled to compensation for native gas.[42]

The Court also rejected Kenai Landing's argument against the lower court's use of the "scope of the project" rule, "which holds that enhancements to the condemned property's value, arising after it becomes likely that the property will be condemned, do not benefit the condemnee."[43] The Court noted that the new gas was not present until CINGSA accidentally discovered it while working on the project, and, the scope of the project rule precludes compensation for the new gas because it was not part of Kenai Landing's property when condemnation proceedings began.[44]

e) The Superior Court Did Not Err in Valuing Kenai Landing's Pore Space Rights

Kenai Landing's remaining arguments on appeal involved the superior court's valuation of its storage rights. Kenai Landing argued that the superior court undervalued these rights by failing to consider the "highest and best use" of the storage space.[45] Instead,

39. *Id*. at 960-61.
40. *Id*. at 961.
41. *Id*.
42. *Id*.
43. *Id*. at 962, citing *City of Valdez v. 18.99 Acres*, 686 P.2d 682, 689 (Alaska 1984).
44. *Kenai Landing, LLC*, 441 P.3d at 962.
45. *Id*.

Kenai Landing sought the application of the "fullest extent rule," "which presumes that the appropriator will exercise [the rights acquired] and use and enjoy the property taken to the full extent."[46] However, the Supreme Court found that application of the fullest extent rule undermines Alaska law on just compensation.

The Court looked to *Martens v. State*,[47] where the Supreme Court previously held that, when there is "a reasonable probability of a change in the near future in the zoning ordinance or other restriction, then the effect of such probability upon the minds of purchasers generally may be taken into consideration in fixing present market value."[48] Because the evidence in the record established that no change in the storage capacity was "reasonably probable" in the near future, the lower court properly declined to apply the fullest extent rule as urged by Kenai Landing.[49]

Kenai Landing also argued that the lower court erred by including the buffer area in valuing the condemned property. Specifically, Kenai Landing argued that by assigning equal value to the buffer area, the superior court diluted the value assigned to the actual pore space and "punishes [Kenai Landing] based on CINGSA's arbitrary determination as to how much non-pore buffer area to include within its proposed 'storage boundary.'"[50] However, the Supreme Court found that the superior court included the buffer area in its valuation as a matter of industry practice after three of CINGSA's experts testified that a buffer zone is "required for prudent operation" of a gas storage field.[51] The experts also testified that a buffer zone is "important to the integrity of a gas field," and that "in the industry no difference is made in the leasing rates applicable to surface land over the reservoir area versus land located over the buffer area."[52] The Supreme Court likewise upheld the lower court's reliance on one of CINGSA's expert's with respect to the actual value of the storage space.[53]

46. *Id*. at 963, citing *Coos Bay Logging Co. v. Barclay*, 159 Ore. 272, 79 P.2d 672, 677 (Or. 1938).
47. 554 P.2d 407, 409 (Alaska 1976).
48. *Id*.
49. *Kenai Landing, LLC*, 441 P.3d at 963-64.
50. *Id*. at 964.
51. *Id*.
52. *Id*.
53. *Kenai Landing, LLC*, 441 P.3d at 965.

B. Cases of the United States District Court for the District of Alaska

i. *League of Conservation Voters v. Trump*[54]

In *League of Conservation Voters*, the United States Court for the District of Alaska considered the scope of a President's authority under Section 12(a) of the Outer Continental Shelf Lands Act ("OCSLA"), finding that Section 12(a) does not endow the President with the authority to revoke withdrawals of unleased land from the Outer Continental Shelf ("OCS").[55]

a) Background

OCSLA was enacted in 1953 with two purposes: (1) "[t]o provide for the jurisdiction of the United States over" OCS lands;[56] and (2) "to authorize the Secretary of the Interior to lease such lands for certain purposes."[57] Section 12(a) of the OCSLA provides: "The President of the United States may, from time to time, withdraw from disposition any of the unleased lands of the outer Continental Shelf."[58]

Plaintiffs[59] sued the federal defendants[60] for an alleged violation of the Constitution's Property Clause, as well as an alleged violation of the statutory authority endowed by Section 12(a) of OCSLA, after President Trump issued Executive Order 13795,[61] intended to revoke three memoranda and one executive order issued by President Obama in 2015 and 2016 withdrawing certain areas of

54. 363 F. Supp. 3d 1013 (D. Alaska 2019).
55. *League of Conservation Voters*, 363 F. Supp. 3d at 1030-1031.
56. Pub. L. No. 83-212, 67 Stat. 462, 462 (1953).
57. *Id*.
58. Pub. L. No. 83-212, § 12(a), 67 Stat. 462, 469 (1953) (codified at 43 U.S.C. § 1341(a)).
59. Plaintiffs included the League of Conservation Voters, Natural Resources Defense Council, Sierra Club, Alaska Wilderness League, Defenders of Wildlife, Northern Alaska Environmental Center, Resisting Environmental Destruction on Indigenous Lands, Center for Biological Diversity, Greenpeace, Inc., and The Wilderness Society.
60. The federal defendants included Donald J. Trump, in his official capacity as President of the United States, Ryan Zinke, in his official capacity as Secretary of the Interior, Wilbur Ross in his official capacity as Secretary of Commerce, American Petroleum Institute, Intervenor Defendant, and State of Alaska, Intervenor Defendant. Guess and Rudd, P.C. represented Intervenor Defendant, American Petroleum Institute.
61. *See* Exec. Order 13795, 82 Fed. Reg. 20815, §§ 4(c), 5 (Apr. 28, 2017).

the Outer Continental Shelf from leasing.[62]

b) The Statutory Text of Section 12(a)

On the plaintiffs' motion for summary judgment, the Court examined both the plain text of Section 12(a) and the context in which it was enacted.[63] In examining the plain language of Section 12(a), the Court noted that, while the text of Section 12(a) expressly grants the President the authority to withdraw unleased lands from the OCS, it does not expressly grant to the President the authority to revoke prior withdrawals.

However, the statute's inclusion of the phrase "from time to time" created ambiguity.[64] Specifically, the phrase could be interpreted in two ways: (1) "to make clear the President's authority to make withdrawals at any time and for discrete periods of time, as well as make withdrawals that extend indefinitely into the future unless and until revoked by Congress;" or (2) "to accord to each President the authority to revoke or modify any prior withdrawal."[65] In light of the ambiguity created by the language of Section 12(a), the Court examined context of Section 12(a) in order to discern Congress's intent.[66]

c) The Context of Section 12(a)

In considering the context of Section 12(a), the Court analyzed the structure of OCSLA, OCLSA's legislative history and prior statutes, the purposes of OCSLA, and OCSLA's subsequent legislative history.

62. *See* Memorandum on Withdrawal of Certain Areas of the United States Outer Continental Shelf Offshore Alaska From Leasing Disposition, DCPD201500059 (Jan. 27, 2015); Exec. Order 13754, 81 Fed. Reg. 90669, § 3 (Dec. 9, 2016); Memorandum on Withdrawal of Certain Portions of the United States Arctic Outer Continental Shelf From Mineral Leasing, DCPD201600860 (Dec. 20, 2016); Memorandum on Withdrawal of Certain Areas off the Atlantic Coast on the Outer Continental Shelf From Mineral Leasing, DCPD201600861 (Dec. 20, 2016).

63. *League of Conservation Voters*, 363 F. Supp. 3d at 1018.

64. *Id*. at 1024.

65. *Id.*

66. *Id*.

1. The Structure of OCSLA

With respect to structure, the Court compared Section 12(a) with Section 8. Section 8 of OCSLA, titled "Leasing of Outer Continental Shelf," authorizes the Secretary of the Interior to lease OCS lands "[i]n order to meet the urgent need for further exploration and development of the oil and gas deposits" beneath the OCS.[67] Section 12 of the Act, as enacted in 1953, was titled "Reservations." Most of the provisions of that section address restrictions on the private use of OCS lands, and no subsection expands private sector use of these lands.[68] Contrasting the two sections, the Court found that Section 8 was intended to promote leasing, while Section 12(a) is "entirely protective,"[69] stating, "Interpreting OCSLA to promote expeditious leasing in Section 8, but according to the President authority to prohibit leasing in specified areas in Section 12(a), gives effect to all of OCSLA's provisions, so that no part will be inoperative or superfluous, void or insignificant."[70] Accordingly, OCSLA's structure promotes the view that Section 12(a) did not grant revocation authority to the President."[71]

2. The Legislative History of OCSLA

In evaluating the legislative history of Section 12(a), the Court rejected the federal defendants' assertion that, because the President has the authority to revoke withdrawals on uplands, Section 12(a) similarly vests the President with the authority to revoke withdrawals of unleased lands on the OCS. The defendants relied on Senate Report No. 83-4, in which the Committee on Interior and Consular Affairs stated that "it was vesting withdrawal authority 'comparable to that which is vested in [the President] with respect to federally owned lands on the uplands.'"[72] The Court

67. Pub. L. No. 83-212, § 8(a), 67 Stat. 462, 468 (1953) (current version at 43 U.S.C. § 1337).
68. Pub. L. No. 83-212, § 12(a)-(f), 67 Stat. 462, 469-70 (1953) (codified at 43 U.S.C. § 1341).
69. *League of Conservation Voters*, 363 F. Supp. 3d at 1025.
70. *Id*. at 1026 (internal citations omitted).
71. *Id*.
72. *League of Conservation Voters*, 363 F. Supp. 3d at 1025, citing S. Rep. No. 83-411, at 26 (1953).

ultimately held that "Congress's silence in Section 12(a) as to according the President revocation authority was likely purposeful; had Congress intended to grant the President revocation authority, it could have done so explicitly, as it had previously done in several (but not all) of its previously enacted uplands laws.[73] The Court also held that Attorney General opinions further establish that Congress intended to authorize the President only to withdraw OCS lands from leasing in Section 12(a).[74] The Court further rejected the argument that the deletion of a provision limiting withdrawal authority from a prior version of Section 12(a) signaled authority to revoke withdrawals, asserting that the deletion afforded the President more discretion in making withdrawals but did not endow the President with the authority to revoke any of those withdrawals.[75]

3. The Purposes of OCSLA

Turning to the purposes of OCSLA, the Court focused on the second purpose of OCSLA—"to authorize the Secretary of the Interior to lease [OCS] lands for certain purposes."[76] The Court noted that, while Congress "clearly sought more leasing," it did not seek "unbridled leasing," given that OCSLA was to "be construed in such manner that the character as high seas of the waters above the outer Continental Shelf and the right to navigation and fishing therein shall not be affected."[77] The Court also noted that Congress's inclusion of Section 12—"Reservations"—was also intended to limit leasing activity:

> The fact that Congress expressly granted the President the authority to withdraw OCS lands from leasing, but did not expressly grant the President the authority to revoke such withdrawals, is not inconsistent with the second purpose of OCSLA as enacted in 1953, particularly as Congress itself retained the

73. *Id*. at 1027.
74. *Id*.
75. *Id*. at 1028.
76. Pub. L. No. 83-212, 67 Stat. 462, 462 (1953).
77. *League of Conservation Voters*, 363 F. Supp. 3d at 1028, citing Pub. L. No. 83-212, Section 3(b), 67 Stat. 462, 462 (1953).

> authority to revoke prior presidential withdrawals pursuant to the Property Clause of the U.S. Constitution.[78]

The Court rejected the federal defendants' contention such an interpretation would allow a President to permanently withdraw the entire OCS from exploration and development, absent intervention from Congress. Looking to prior Attorney General opinions, the Court found that, "Congress has previously authorized the President to tie future Presidents' hands."[79] While Section 12(a) technically allows a President to permanently withdraw all unleased lands on the OCS, the Court noted that Congress could reverse such an action by either revoking the withdrawal itself or amending Section 12(a) to expressly allow a President to revoke a prior presidential withdrawal.[80]

4. The Subsequent History of OCSLA

Finally, in considering OCSLA's subsequent history, the Court held that Congress's decisions not to challenge prior revocations did not meet the "high bar required to constitute acquiescence."[81] In addition, Congress's lack of action regarding Section 12(a) did not allow the Court to draw any appropriate inference that would "override" the Court's interpretation of Section 12(a) based on the section's language and legislative history prior to its enactment.[82]

Based on the context in which Section 12(a) was enacted, the Court granted plaintiffs' motion for summary judgment, declaring the revocation of Executive Order 13795 invalid and unlawful and vacating Section 5 of the Order.[83] The defendants have since filed

78. *League of Conservation Voters*, 363 F. Supp. 3d at 1029.

79. *Id*. at 1029.

80. *Id*.

81. *Id*. at 1030, citing *United States v. Midwest Oil Co.*, 236 U.S. 459, 469-71 (1915) (holding that presidential withdrawal of public lands was lawful because Congress had "uniformly and repeatedly acquiesced" to the President's creation of roughly 250 reservations).

82. *Id*. (internal citations omitted).

83. *Id*. at 1030-31.

notices of appeal with respect to the Court's ruling.[84]

84. See Notice of Appeal by Wilbur Ross, Donald J. Trump, Ryan Zinke, League of Conservation Voters et al v. Trump et al, No. 3:17-cv-00101-SLG (D. Alaska May 28, 2019); Notice of Appeal by American Petroleum Institute, League of Conservation Voters et al v. Trump et al, No. 3:17-cv-00101-SLG (D. Alaska May 28, 2019); Notice of Appeal by State of Alaska, League of Conservation Voters et al v. Trump et al, No. 3:17-cv-00101-SLG (D. Alaska May 28, 2019).

ARKANSAS

*J. Mark Robinette**

There is very little to report in Arkansas this year. The 92nd General Assembly made no substantive changes to the law of oil and gas in Arkansas. In addition, the federal courts produced no significant developments.[1] In state court, there were two notable cases.

The case of *Arkansas Oil & Gas Comm'n v. Hurd*, began as an examination of the Oil and Gas Commission's authority regarding compulsory leasing and pooling but ended with a bizarre twist. In the administrative proceeding, SWN Arkansas Production Company, LLC sought to show that the leases of two mineral owners were "self-dealing, non-arm's length" transactions.[2] These owners received a 25% royalty under the alleged self-dealt leases, while SWN gave no more than a 1/7 royalty in leases it negotiated in the unit.[3] The

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1. Smith v. SEECO, 922 F.3d 398 (8th Cir. 2019) (deciding the only oil and gas case in the federal courts on procedural grounds with no special impact on the law of oil and gas).
2. *Id*. at 409.
3. *Id.*

Commission sided with SWN, and the mineral owners appealed to Pulaski County Circuit Court pursuant to the Arkansas Administrative Procedures Act.[4]

During the appeal to the circuit court, the Arkansas Supreme Court issued the opinion of *Board of Trustees of the University of Arkansas v. Andrews*. This opinion held that the State of Arkansas cannot waive its sovereign immunity via laws enacted by the General Assembly.[5] The Commission moved to dismiss the appeal utilizing *Andrews* to argue that being named a defendant in circuit court under the Arkansas Administrative Procedures Act violated the sovereign immunity doctrine.[6] The Circuit Court of Pulaski County granted the Commission's motion to dismiss, but not before holding that the lack of a right of review of administrative action in light of the *Andrews* decision rendered the entire Arkansas Administrative Procedures Act unconstitutional.[7]

The Arkansas Supreme Court took the Commission's appeal from the circuit court.[8] Using a clever pivot on the issue of the Commission's status as a party to the appeal to circuit court, the Court found that the Commission was not a defendant in the action. Instead, the Commission was "akin to a trial court in an appellate proceeding; it has no vested interest in the outcome of the appeal other than whether its decision is upheld."[9] As a result, the Court abrogated and remanded the circuit court's opinion.[10]

The decision was a sensible compromise allowing the continuing operation of the Oil & Gas Commission. If the trial court's

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4. *Id.* ARK. CODE ANN. § 15-72- A-2(j)(1)(c) (2019) (requiring an applicant seeking force pooling to provide information on the highest bonus and royalty known in the unit); ARK. CODE ANN. §15-72-304(b)(4) (explaining this is the basis under which an unleased mineral owner who fails to affirmatively elect to participate in the unit gets compensated for transfer of his rights under); Walls v. Arkansas Oil & Gas Comm'n, 390 S.W.3d 88 (Ark. 2012) (explaining information about the "highest" bonus and royalty is only an evidentiary requirement, then the information is then subject to "reasonable consideration and a reasonable basis" and is not "fair market value." As such, some mineral owners subject to force pooling react by entering into leases with entities they own at higher terms than those proposed by the applicant. This case is a test of how far mineral owners who self-deal may go).

5. Ark. Oil and Gas Comm'n v. Hurd, 564 S.W.3d 248, 250 (Ark. 2018) (explaining the Arkansas Constitution provides that "[t]he State of Arkansas shall never be made a defendant in any of her courts"); ARK. CONST. art. 5, § 20.

6. Board of Trustees v. Andrews, 535 S.W.3d 616, 622–23 (Ark. 2018).

7. *Arkansas Oil and Gas Comm'n*, 564 S.W.3d at 250–51.

8. *See id.* at 253.

9. *Id.* at 255.

10. *Id*.

decision had stood, it would practically end the functionality of all state administrative agencies. In addition, the trial court opinion would require an amendment of the Arkansas Constitution. The language of the Constitution is very clear, and it was the basis of the *Andrews* decision. Unfortunately, the merits of the underlying issue in the *Hurd* case are not yet reported, though an appeal is pending.

A class was successfully certified for thirty-six persons in a claim against a gas producer in *Stephens Production Company v. Mainer*. The trial court certified the class as those underpaid royalties on "proceeds" leases within a certain production unit in Franklin County, Arkansas.[11] The gas producer's resistance to the class action certification was principally the size of the class.[12] In a prior case cited by the producer, a class of seventeen persons failed to meet the numerosity requirement of Arkansas's Rule Civil Procedure 23 regarding class actions.[13] The Court reiterated that it has no bright-line test on the exact number needed to satisfy the numerosity requirement and that "common sense" controls.[14] Not elaborating on this standard of common sense, the Court instead noted there was no abuse of discretion by the trial court.[15] More importantly, in a close case of whether or not there is numerosity, erring on the side of certification is favored by the Court because it is possible to decertify the class at a later date.[16]

Justices Wood, Kemp, and Womack dissented from the majority's opinion.[17] The thrust of the dissent was that there were no findings by the trial court on "geographic dispersion of class members, the size of individual claims, the financial resources of the class members, or the ability of claimants to institute individual suits."[18] Without these findings, the dissent would have found that the trial court abused its discretion.[19]

Stephens Production Company seems to allow a presumption that lessors in a production unit under a common lessor are a viable class of plaintiffs. If so, this may result in a new round of litigation of

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11. Stephens Prod. Co. v. Mainer, 571 S.W.3d 905, 907 (Ark. 2019).
12. *Id*.
13. *Id*. at 908.
14. *Id*.
15. *Id*.
16. *Id*.
17. *Id*. at 910.
18. *Id*.
19. *Id*.

"micro" class actions. One could certainly imagine the use of this tactic in both royalty disputes within units and implied covenant cases within units in Arkansas.

CALIFORNIA

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I. INTRODUCTION

Although California continues to transition away from its historical status as one of the nation's most important oil and gas-producing states,[1] California is still among the top-ten states in oil

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1. *See, e.g.*, Rob Nikolewski, *California's ranking as an oil-producing state is slipping*, SAN DIEGO UNION-TRIBUNE (Jul. 12, 2018, 5:00 AM), https://www.sandiegouniontribune.com/business/energy-green/sd-fi-california-crudeoil-20180711-story.html [https://perma.cc/963K-WV4G] (noting that "[i]n 1985, California field production reached 394 million barrels", but that "[i]n 2017, the state produced 173.2 million barrels- a 56 percent drop").

production[2] and produces a significant amount of natural gas.[3] California has a long history of oil and gas exploration, production, refinement, and marketing, and as a result, well-established common law principles and statutory and regulatory laws are in place that govern all facets of the industry. The following update summarizes key changes in California oil and gas law for the survey period from January 1, 2019 to October 15, 2019.

II. LEGISLATIVE ACTIVITY

Legislative activity in California over the survey period remained consistent with previous sessions, meaning numerous bills were introduced to further regulate oil and gas production in California but only some were passed by the Legislature and signed into law by the Governor. The most significant of these are summarized below.

A. *Assembly Bill No. 1057*[4]

Assembly Bill No. 1057 ("AB 1057") effects several changes to California oil and gas regulation by amending portions of the California Government Code, the Public Resources Code, and the Health & Safety Code. For instance, AB 1057 renames the state's main oil and gas regulatory agency from the Division of Oil, Gas, and Geothermal Resources ("DOGGR") to the Geological Energy Management Division ("CalGEM"),[5] and codifies the purposes of the division to include "protecting public health and safety and environmental quality, including reduction and mitigation of greenhouse gas emissions associated with the development of hydrocarbon and geothermal resources in a manner that meets the

2. *See Rankings: Crude Oil Production, July 2019*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/state/rankings/#/series/46 [https://perma.cc/2RNG-3LZH] (last visited Oct. 25, 2019).

3. *See Natural Gas Gross Withdrawals and Production*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm [https://perma.cc/7U6Q-SR47] (last visited Oct. 25, 2019).

4. Assemb. B. 1057, 2019 Leg., 2019-2020 Reg. Sess. (Cal. 2019) (Approved by the Governor on October 12, 2019, and chaptered by the Secretary of State as Chapter 771 on October 12, 2019.)

5. Assemb. B. 1057 § 6 (amending CAL. PUB. RES. CODE § 3002 (West 2019)).

energy needs of the state."[6] In this latter respect, AB 1057 requires the State Oil and Gas Supervisor (as head of CalGEM) to coordinate with other state agencies and entities (including industry sectors, business groups and environmental organizations) in furtherance of the State's clean energy goals under the California Global Warming Solutions Act of 2006 (California Health & Safety Code § 38500 et seq.).[7] Interestingly, however, AB 1057 does not amend other existing statutory law that expressly provides that the State Oil and Gas Supervisor's duties include supervising the drilling and operation of wells in the state so as to prevent loss of oil, gas, or reservoir energy and to permit the owners or operators of wells to utilize all methods and practices known to the oil and gas industry for the purpose of increasing the ultimate recovery of underground hydrocarbons.[8]

Of all the changes effected by AB 1057 (which also include requiring additional information from parties involved in the sale and purchase of oil and gas wells and facilities[9]), the most concerning to operators is that, effective January 1, 2020, CalGEM may require an operator to provide additional security (i.e., on top of current bonding requirements) of up to $30M based on the division's evaluation of the risk that the operator will desert its well(s) and the potential threats its well(s) may pose to life, health, property, and natural resources.[10]

B. *Assembly Bill No. 342*[11]

Assembly Bill No. 342 ("AB 342") adds Section 6827.5 to the California Public Resources Code. This statute prohibits (with limited exceptions) any state entity with leasing authority over state lands from entering into any new lease or other conveyance authorizing new construction of oil- and gas-related infrastructure upon state-owned lands to support production of oil and gas upon federal lands that are or were previously designated as a national monument, park,

6. Assemb. B. 1057 § 9.
7. *Id.*
8. CAL. PUB. RES. CODE § 3106(a)–(b) (West 2019).
9. *See* Assemb. B. 1057 §§ 11–12.
10. Assemb. B. 1057 § 13.
11. Assemb. B. 342, 2019 Leg., 2019-2020 Reg. Sess. (Cal. 2019) (Approved by the Governor on October 12, 2019, and chaptered by the Secretary of State as Chapter 769 on October 12, 2019).

wilderness area, wildlife refuge, or wilderness study area.[12] This bill was a direct response to the Trump Administration's plans to expand oil and gas production on federal land in California[13] and follows last year's passage of duplicative measures: Senate Bill No. 834[14] and Assembly Bill No. 1775.[15] These prohibit the California State Lands Commission ("SLC") or a public trustee from entering into any new lease or other conveyance authorizing new construction of oil- and gas-related infrastructure upon tidelands and submerged lands within state waters associated with any federal offshore oil and gas lease issued after January 1, 2018.[16]

C. *Assembly Bill No. 585*[17]

Assembly Bill No. 585 ("AB 585") amends Section 6804 of and adds Section 6829.4 to the California Public Resources Code, relating to oil and gas leases and permits covering state-owned lands and administered by SLC. In particular, AB 585:

- Authorizes SLC, when considering an approval of an assignment, transfer or sublease of an oil and gas lease or permit, to take into account whether the proposed assignee, transferee or sublessee is likely to comply with the terms of the assigned lease or permit for its duration, as determined by specified factors;[18]
- Requires any SLC-approved assignment, transfer or sublease (or memorandum thereof) of an oil and gas

12. *Id.*
13. Associated Press, *Gov. Gavin Newsom Signs Bill Limiting Oil and Gas Development* (October 12, 2019, 4:23 PM), L.A. TIMES https://www.latimes.com/california/story/2019-10-12/gov-gavin-newsom-signs-bill-limiting-oil-and-gas-development [https://perma.cc/NZ4T-G7AR] (last visited Oct. 25, 2019).
14. S.B. 834, 2018 Leg., 2017-2018 Sess. (Cal. 2018) (Approved by the Governor on September 8, 2018 and chaptered by the Secretary of State as Chapter 309 on September 8, 2018.).
15. Assemb. B. 1775, 2018 Leg., 2017-2018 Sess. (Cal. 2018) (Approved by the Governor on September 8, 2018 and chaptered by the Secretary of State as Chapter 310 on September 8, 2018.).
16. *Id.*
17. Assemb. B. 585, 2019 Leg., 2018-2019 Sess. (Cal. 2019). (Approved by the Governor on July 30, 2019, and chaptered by the Secretary of State as Chapter 123 on July 30, 2019.).
18. *Id.*

lease or permit covering state-owned lands to be recorded in the office of the county recorder of the county in which the leased or permitted lands are located;[19] and

- Deletes existing provisions releasing and discharging an assignor or transferor from obligations accruing under an oil and gas lease or permit after the assignment, transfer or sublease of the same and instead provides (subject to a few exceptions) that the assignor, transferor or sublessor shall remain liable for, and not be released or discharged from, obligations under the lease or permit, including requirements relating to plugging and abandoning wells, decommissioning facilities, and completing well site and lease restoration.[20]

D. *Senate Bill No. 551*[21]

Senate Bill No. 551 ("SB 551") amends Sections 3206.3 and 3258 of and adds Section 3205.7 to the California Public Resources Code, relating to oil and gas well plugging and abandonment liabilities. In particular, SB 551 provides that commencing July 1, 2022, CalGEM shall require oil and gas operators in the state to submit an initial report to the division (on a schedule to be determined by the division) demonstrating the operator's total liability to plug and abandon all wells and to decommission all attendant facilities, including any needed site remediation.[22] Follow-up reporting is required on a continual basis that shall be no less frequent than every five years after each operator's initial report.[23]

CalGEM must develop criteria to be used by operators for estimating their costs to plug and abandon their wells and decommission their facilities.[24] If the State Oil and Gas Supervisor

19. *Id.*
20. *Id.*
21. S.B. 551, 2019 Leg., 2018-2019 Sess. (Cal. 2019). (Approved by the Governor on October 12, 2019, and chaptered by the Secretary of State as Chapter 774 on October 12, 2019.).
22. *Id.*
23. *Id.* (enacting PUB. RES. CODE § 3205.7(a)(2)).
24. *Id.*

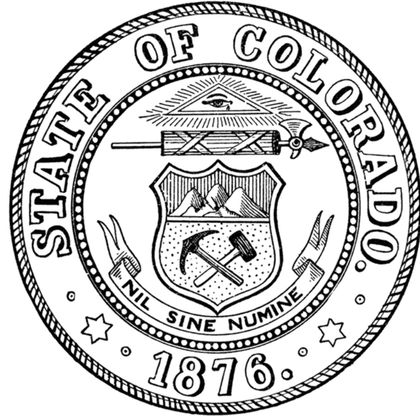
determines that an operator has failed to use the requisite criteria or has otherwise provided estimates that are neither credible nor accurate, it may request the operator to submit revised estimates for further review and approval.[25]

III. REGULATORY ACTIVITY

Regulatory activity affecting the California oil and gas industry during the survey period continued to focus on a variety of issues. In particular, new regulations regarding underground injection control and idle wells became operative in April 2019.[26]

25. *Id.* (enacting PUB. RES. CODE § 3205.7(d)).

26. *See Oil, Gas, and Geothermal Laws and Rulemaking*, CAL. DEP'T CONSERVATION, https://www.conservation.ca.gov/dog/Pages/Oil,-Gas,-and-Geothermal-Rulemaking-and-Laws.aspx [https://perma.cc/W6JP-HR9B] (last visited Nov. 8, 2019) (summary and links to updated regulations relating to underground injection control and idle wells).



COLORADO
THE CHANGING LANDSCAPE OF LAND USE LAW AND REGULATIONS IMPACTING THE COLORADO OIL AND GAS INDUSTRY: FROM THE COLORADO OIL AND GAS CONSERVATION ACT OF 1951 TO SENATE BILL 181 OF 2019

Ralph A. Cantafio, Esq.[1]

When Colorado Democratic Governor Jared Polis approved Senate Bill 181, this new law significantly redirected the historical focus of Colorado oil and gas regulation.[2] This provided a significant

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2. Dale Ratliff, *Senate Bill 19-181: Colorado enacts first-of-its*

delegation of land use related authority to local government for the first time since the passage of this Act in 1951. This new law moved away from the traditional notion of statewide regulation based upon exclusive jurisdiction by the Colorado Oil and Gas Conservation Commission ("COGCC"). While this change of legislative focus is significant, this latest direction is probably a natural continuation of a general trend that has been emerging in Colorado since certain Supreme Court Opinions were announced in 1992, as explained later in this Article. As the State of Colorado has, among other things, grown in population, residential housing now significantly finds itself competing with oil and gas development in the same geographical areas, especially the suburbs of the "Front Range." Simultaneously, the political sentiment of Colorado has trended into a more significantly Democratic direction from a historically Republican majority. The law as to the governance of the oil and gas industry has now changed as a result of the passing of SB 181—from fostering the development of oil and gas industry to a new paradigm requiring the weighing of interests, including environmental concerns. This Article provides a historic explanation to allow the reader to better understand how this transition has come about. That which is observed in Colorado might also be seen as a potential harbinger of future change that could be noted in other oil and gas states.

I. THE ACT

The Colorado Oil and Gas Conservation Act ("The Act") was enacted in 1951.[3] It sought to address a host of objectives. Part of the legislative objective in passing this Act was to provide a single and monolithic set of laws that would apply to the development of a statewide oil and gas industry. While no single statement could summarize the multitude of sentiments of the entirety of the Colorado legislature in passing this law (as is the case with virtually every piece of legislation), creating a state-wide system for the permitting,

kind oil and gas legislation, A.B.A. (Oct. 25, 2019) https://www.americanbar.org/groups/environment_energy_resources/publications/trends/2019-2020/november-december-2019/senate-bill/ [https://perma.cc/PW94-HMRZ].

3. 1951 Colo. Sess. Laws 651, 662 (repealing COLO. STAT. ch. 118, §§ 39, 40, 41, 42, 43, 44, 49, 50, 52, 64, 65, 66, and 67 (1935)) (codified at COLO. REV. STAT. § 34-60-101) (1951).

licensing, and regulation of the oil and gas industry made sense from the point of view of promoting its prosperity. So, too, was the reality that the Act recognized that individual cities or most counties did not have either the local budget or the available expertise to meaningfully provide regulation of what is an admittedly complex and technical industry. It is also important to recall that near the time that the Act was passed, the total population of Colorado was 1,325,089.[4] By 2015, the population of Colorado had grown to 5,456,571.[5] It is important to keep in mind the vast changes Colorado has experienced in the last sixty-five plus years. Infrastructure that is taken for granted today, such as Interstate-25 or Interstate-70, did not exist some sixty-five years ago (although there was a statewide road system).[6]

Until perhaps the 1980s, much oil and gas development occurred in relatively unimproved geographical areas that were sparsely populated, occurring primarily nearby agricultural communities.[7] With the ever-growing population growth of the Colorado "Front Range" (which generally is defined as Ft. Collins to the north and Pueblo to the south along the I-25 corridor) land use issues and issues resulting from an encroaching population intersecting with that of the oil and gas industry became inevitable. Nonetheless, the general legal framework pertaining to the regulation of oil and gas industry was one focused on stateside regulation through approximately 1992.

II. THE 1992 COLORADO SUPREME COURT DECISIONS

On June 8, 1992, the Colorado Supreme Court announced two opinions that significantly changed the legal landscape of oil and gas regulation in Colorado: (1) *The Board of County Commissioners, of*

4. U.S. DEP'T COMMERCE, No. 4, 1950 CENSUS OF POPULATION PRELIMINARY REPORTS (1950).

5. *Colorado's 2016 Population & Economic Overview,* COLO. STATE DEMOGRAPHY OFF. (Feb. 7, 2017) https://demography.dola.colorado.gov/crosstabs/2016-overview/ [https://perma.cc/Z4EY-MNRN].

6. *Fun Facts,* COLO. DEP'T TRANSP., https://www.codot.gov/about/CDOTHistory/50th-anniversary/fun-facts.html [https://perma.cc/2A4Z-JENR] (last visited Nov. 7, 2019).

7. *See* Kathryn M. Mutz, *Home Rule City Regulation of Oil and Gas Development*, 23 COLO. L. 2771, 2771 (1994).

La Plata County vs. Bowen/Edwards Associates, Inc.[8] and (2) *Voss vs. Lundvall Brothers, Inc*.[9] Justice Joseph Quinn authored each opinion. As you will read, traditional notions of preemption by the COGCC were reconsidered.[10]

The more straightforward case is *Voss*. Here, the City of Greeley enacted a land use ordinance that imposed a complete ban on the drilling of any oil, gas, or hydrocarbon wells within the city limits.[11] The Greeley City Counsel enacted Greeley Ordinance 90 prohibiting any drilling for oil and gas within city limits.[12] An issue raised included whether or not this Ordinance violated Article V, Section 35 of the Colorado Constitution.[13] The Plaintiffs, Lundvall Brothers, filed their lawsuit seeking Declaratory Relief. They asked the court to declare the Greeley Ordinance as null and void in violation of the Act.[14]

The District Court of Weld County found that the Greeley Ordinance was facially void because "the entire area of oil and gas exploration and regulation, including location of sites within municipalities [has] been preempted by the State of Colorado" and "[has been] delegated to the Oil and Gas Conservation Committee Commission."[15]

This order by that District Court was in substantial concurrence with the traditional notions of preemption Colorado courts had enforced since this Act became law. However, and as discussed below, the sister opinion of *Bowen/Edwards*, as relied upon in *Voss,* now directed Colorado oil and gas regulatory law into a new, more collaborative direction. Justice Quinn noted:

> The Oil and Gas Conservation Act, [cite omitted] **does not totally preempt a county from exercising its land use authority** over any and all aspects of oil and

8. 830 P.2d 1045 (Colo. 1992)
9. 830 P.2d 1061 (Colo. 1992)
10. *See Bowen/Edwards Assocs.*, 830 P.2d at 1056–57; *Voss*, 830 P.2d at 1069.
11. *Voss*, 830 P.2d at 1063.
12. *Id.*
13. *Id.* at 1069.
14. *Id.* at 1063.
15. *Id.* (quoting Lundvall Bros., Inc. v. Voss, 812 P.2d 693 (Colo. App. 1990)).

> gas development operations in unincorporated areas of the county. In the instant case we must determine whether the scope of Greeley's authority as a home-rule city to delegate land use within its municipal borders extends to a total ban on the drilling of an oil, gas, or hydro carbon well within its city limits.[16]

Citing the sister *Bowen/Edwards* opinion, Justice Quinn further noted in *Voss*:

> in addition to issuing permits for oil and gas drilling operations, the Commission is authorized to regulate the drilling, production, and plugging of wells, the shooting and chemical treatment of wells, the spacing of wells, and the disposal of set water and oil field wastes [cite omitted] as well as to limit production for any pool or field for the prevention of waste and allocate production from pool or field among or between tracts of land having separate ownership on a fair and equitable basis so that each tract will produce no more than its fair share[17]

Ultimately, Justice Quinn determined that the Greeley Ordinance violated basic conscripts of the Act:

> We conclude that the state's interests in efficient oil and gas development and production throughout the state, as manifested in the Oil and Gas Conservation Act, is sufficiently dominant to override a home-rule cities in position of a total ban on the drilling of any oil, gas, or hydro carbon wells within the city limits. In so holding, we do not mean to imply that Greeley is prohibited from exercising a land-use authority over those areas of the city in which oil and gas activities are occurring or are contemplated."[18]

16. *Id.* at 1064 (emphasis added).
17. *Id.* at 1065.
18. *Id.* at 1068.

Bowen/Edwards focused on a different issue: whether or not the Act preempted La Plata County's authority to enact land-use regulation that, as a by-product, limited oil and gas operations within that county.[19] Up until the announcement of this case, the understanding had been that a declared purpose of the Act was to preempt county intervention, even when such county regulation incidentally impacted the oil and gas industry.[20] Justice Quinn seized upon the 1985 Amendments to the Act which spoke to the growing overlap of the oil and gas industry into more densely populated areas.[21] Based upon those Amendments, the COGCC was found to possess authority to "promulgate rules and regulations to protect the health, safety, and welfare of the general public and the drilling completion, and operation of oil and gas wells in production facilities."[22] La Plata County passed a set of land-use regulations, which contained the following Statement of Purpose:

> these regulations are enacted to protect and promote the health, safety, morals, convenience, order, prosperity or general welfare of the present and future residences of La Plata County. It is the counties intent by enacting these regulations to facilitate the development of oil and gas resources within the unincorporated area of La Plata County while mitigating potential land use conflicts between such development and existing, as well as planned, land uses.[23]

Justice Quinn observed that three fundamental grounds existed upon which a Colorado state statute could preempt a county ordinance or regulation: (1) the express language of the statute indicated the state may preempt local authority over the subject matter in question; (2) preemption could be inferred if the state statute impliedly evinces a legislative intent to completely occupy a given field; or (3) a local law may be partially preempted where its **operational effect** would

19. Bd. of Cty. Comm'rs v. Bowen/Edwards Assocs., Inc., 830 P.2d 1045, 1057 (Colo. 1992).
20. *Id.*
21. *Id.* at 1049.
22. *Id.* (citing COLO. REV. STAT. § 34-60-106(11) (1991)).
23. *Id.* at 1050 (citing La Plata County Regulation § 6.103)..

conflict with application of the state statute.[24] The Colorado Supreme Court ultimately remanded the matter for the taking of further evidence instructing:

> on the basis of the limited record before us, we are unable to determine whether an **operational conflict** exists between La Plata County's oil and gas regulations and the Oil and Gas Conservation Act. The purpose of the county regulations is to 'facilitate the development of oil and gas resources within the unincorporated area of La Plata County while mitigating potential land use conflicts we have seen between such development existing, as well as planned, land uses' [cite omitted] this statement of purpose evinces an obvious intent to regulate in a manner that does not hinder the achievement of the State's interests in fostering the efficient development, production, and utilization of oil and gas resources in the state [cite omitted][25]

Justice Quinn:

> The County's regulations also appear to be designed to harmonize oil and gas development and operational activities with the state's overall plan for land use and with the state's interest in those development and operational activities[26]

Bowen/Edwards as a result created a legal environment where some twenty-five years of litigation ensured typical harkening upon the application of the terms "operational effect" and "operational conflict."

III. AMENDMENT 74 AND PROPOSITION 112

24. *Id.* at 1056–57.
25. *Id.* at 1059–60.
26. *Id.* at 1060.

By November 2018, despite a multitude of litigations, the issue as to the local regulation of land use impacting the oil and gas industry has migrated from the judicial branch of government to that of the ballot box.[27] Colorado voters were faced with a decision as to Amendment 74 and Proposition 112. Proposition 112 was an initiative that would have increased oil and gas drilling setbacks, globally speaking, distancing oil wells from homes, businesses, and waterways.[28] This Proposal included a 500-foot setback from homes and a 1000-foot setback from schools. New oil and gas developments would also have been subject to a 2,500-foot setback.[29]

On the same ballot, Amendment 74, if passed, would have permitted property owners to seek compensation from government entities any time a government action or regulation devalued their property.[30] Additionally, the Amendment would have allowed private homeowners to seek judicial intervention and, under appropriate circumstances, compensation for takings type claims based on a government action or regulation that devalued property.[31]

Under Amendment 74, a government regulation or government permit and/or license that is part and parcel with oil and gas development could have been characterized as an act that would subject the government to liability for essentially a taking.[32]

Proposition 112 was ultimately defeated by approximately 57% to 43%.[33] Amendment 74 was simultaneously defeated by approximately 54% to 46%.[34] Although defeated, each demonstrated a very strong sentiment held by certain segments of the Colorado voting population that the then current regulations pertaining to the development of oil and gas was perceived as inadequate.

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27. LEGIS. COUNCIL OF THE COLO. GEN. ASSEMB., 2018 STATE BALLOT INFORMATION BOOKLET, NO. 702-2 (2018).
28. *Id.* at 82.
29. *Id.*
30. *Id.* at 52.
31. *Id.*
32. John Aguilar, *Prop 112 Fails as Voters Say No to Setbacks for Oil and Gas*, THE DENVER POST (NOV. 6, 2018, 7:13 PM), https://www.denverpost.com/2018/11/06/colorado-proposition-112-results/ [https://perma.cc/B2MJ-8AZX].
33. *Id.*
34. *Id.* (noting that the Amending of the Colorado Constitution now requires approval by a super majority of 55% to become law).

IV. MARTINEZ

In January 2019, the Colorado Supreme Court decided *Martinez v. Colorado Oil & Gas Commission*.[35] The Plaintiffs here were self-described youth activists. They dedicated substantial effort towards pursuing their objective of protecting the health of Colorado citizens and its environment.[36] These Plaintiffs proposed to the COGCC a rule that would have, among other things, prohibited the COGCC from issuing any permits for the drilling of oil and gas wells "unless the best available science demonstrates, and an independent third party confirms, the drilling can occur in a manner that does not cumulatively, with other actions, impair Colorado's atmosphere, water, wildlife, and land resources, does not adversely impact human health, and does not contribute to climate change."[37] The COGCC in response to this proposed rule solicited and received public comment. It thereafter declined to engage in rulemaking to further consider the proposed rule because:

> (1) the rule would have required the commission to readjust the balance purportedly crafted by the General Assembly under the Act and condition new oil and gas drilling on a finding of no cumulative adverse impacts, both of which the Commission believed to be beyond its statutory authority, and (2) the Commission was already working with the Colorado Department of Public Health and Environment ("CDPHE")" to address the concerns to which the Rule was directed and other Commission priorities took precedence over the proposed rule making at the time.[38]

The case at hand is interesting. The Colorado Court of Appeals disagreed with the District Court. The Colorado Court of Appeals found in favor of the Plaintiffs.[39] The Court of Appeals found that the COGCC and the District Court erred in determining the scope of the

35. 433 P.3d 22 (Colo. 2019).
36. *Id.* at 24.
37. *Id.* at 25.
38. *Id.*
39. *See id.*

authority of the COGCC under the Act. It decided the COGCC was responsible for "fostering balanced, non-wasteful development [that] is completed subject to the protection of healthy safety and welfare."[40]

> The Colorado Supreme Court ultimately reversed:
> First our review of an administrative agency's decision is to whether to engage in law making is limited and highly deferential. Second, in our view, the Commission correctly determined that, under the applicable language of the Act it could not properly adopt the rule proposed by respondents. Specifically, as the Commission recognized, the pertinent provisions do not allow it to condition all new oil and gas development on a finding of no cumulative adverse impacts to public health and environment. Rather, the provisions make clear that the commission is required to (1) **to foster** the development of oil and gas resources, protecting and enforcing the rights of owners and producers; and (2) in doing so, to prevent and mitigate significant adverse environmental impacts to the extent necessary to protect public health, safety and welfare, but only after taking into consideration cost effectiveness and technical feasibility[41]

Out of the substance of this opinion, it is this "fostering" of the development of oil and gas resources as an objective of the Act that would be rejected by Senate Bill 181.[42]

The Colorado Supreme Court found:

> these provisions do not allow the Commission to condition all new oil and gas development on a finding of no cumulative adverse impacts to public health and the environment, as Respondents assert the commission must do. Nor do we perceive the statutory language as creating a balancing test by which the publics interests in oil and gas development is weighed

40. *Id.* at 24.
41. *Id.* at 25.
42. S.B. 9-181, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019).

> against its interest in public health and the environment, as Petitioners seem to suggest. Rather, in our view, the pertinent provisions make clear the commission is required (1) **to foster** the development of oil and gas resources, protecting and enforcing the rights of owners and producers, and to in doing so, to prevent and mitigate significant adverse environmental impacts to the extent necessary to protect public health, safety, and welfare, but only after taking into consideration cost effectiveness and technical feasibility[43]

V. SUMMARY OF THE STATE OF THE REGULATION OF OIL AND GAS/PRE-2019 LEGISLATIVE SESSION

Post *Martinez*, a summary of Colorado law pertaining to the regulation of the oil and gas industry was the COGCC was charged with "fostering" the responsible and balanced development, production, and utilization of oil and gas in a manner consistent with the protection of public health, safety, and welfare, including protection of the environment and wildlife resources.[44] The COGCC was further responsible for protecting public and private interests in oil and gas against waste.[45] The COGCC was afforded broad latitude to carry out its statutory mandate under circumstances where the COGCC adopted rules that governed the operational aspects of oil and gas operations to implement this as authority.[46] Applying *Voss* and *Bowen/Edwards*, a home-rule entity in implementing land use regulation first must apply the same only within its physical jurisdiction.[47] Recall, oil and gas reservoirs do not always neatly conform to man-made boundaries. Next, so long as such regulation does not frustrate development of and at the same time could be harmonized with the development of oil and gas in a manner consistent

43. *Martinez*, 433 P.3d at 41.
44. COLO. REV. STAT. § 34-60-102(I) (2019).
45. § 34-60-102(II).
46. COLO. REV. STAT. §§ 34-60-105 to 34-60-106 (2019).
47. Voss v. Lundvall, Inc., 830 P.2d 1061, 1068 (Colo. 1992); Bd. of Cty. Comm'rs v. Bowen/Edward Assocs., Inc., 830 P.2d 1045, 1056 (Colo. 1992).

with the stated goals of the Act, home-rule regulation would be given effect.

VI. SENATE BILL 181

With the election of Democratic Governor Jared Polis in November 2018, and the Colorado Senate and House of Representatives now controlled by a Democratic majority, the temperament and objectives as to historic regulation of the oil and gas industry in Colorado changed precipitously.[48] Pre-Senate Bill 181, the Mission Statement of the Act was to:

> **foster** the responsible, balanced, development and production and utilization of the natural resources of oil and gas in the state of Colorado in a manner consistent with protection of public health, safety and welfare, including protection of the environment and wildlife resources.[49]

After adoption of Senate Bill 181, the mandate of the COGCC significantly changed:

> the commission shall regulate oil and gas operations in a reasonable manner to protect and minimize adverse impacts to public health, safety, and welfare, the environment, and wildlife resources and shall protect against adverse environmental impacts on any air, water soil, or biological resource resulting from oil and gas operations.[50]

VII. CURRENT IMPLEMENTATIONS OF SENATE BILL 181

As of Fall 2019, the COGCC is engaged in implementing Senate Bill 181 and is in the midst of increasing protection of public health, safety, welfare, environment, and wildlife, while considering

48. § 34-60-102(1)(a).
49. *Id.* (emphasis added).
50. § 34-60-106(2.5)(a).

these cumulative impacts on the oil and gas industry.[51] The COGCC is currently enacting what it calls a "neutral" regulatory framework, as opposed to one that "fosters" the development of the oil and gas industry.[52] COGCC is currently establishing a "holistic and contextual decision making process" with an objective, in part, of developing increased public trust in the COGCC.[53] Most significantly, there is a significant restructuring of the very relationship between state and local government as to oil and gas regulation.[54] The notion of preemption, first modified by *Bowen/Edwards*, has now been substantially abandoned.

Potential new rules and practices include:

1. Requiring emergency response plans and tactical response plans as conditions to permit filings.
2. Incorporating new environmental and safety protections to existing facilities.
3. Minimizing flaring and truck traffic.
4. Examining the efficacy of mechanical integrity testing (MITs).
5. Reforming spill reporting.
6. Evaluating best management practices in the context of multi-well horizontal developments.
7. Developing alternative site analysis in conjunction with local government regulation.
8. Creating basin-wide spacing.
9. Using cumulative impacts to evaluate and develop permit reviews and best managed practices.
10. Right sizing or re-examining the locating of well paths.
11. Examining cumulative impacts to better address noise, odor, and other nuisances.

51. COLO. REV. STAT. § 29-20-104(1)(h) (2019).
52. KEYSTONE CENTER, COLORADO OIL & GAS TASK FORCE FINAL REPORT 3 (2015), https://www.colorado.gov/pacific/sites/default/files/atoms/files/2015%20Oil%20Gas%20Task%20Force%20Report.pdf [perma.cc/2L4D-BA7C].
53. JEFF ROBBINS, INSIGHTS INTO COGCC RULEMAKING FROM 30,000', COLO. OIL & GAS CONSERVATION COMM'N 19–22 (2019), https://cogcc.state.co.us/documents/sb19181/Overview/SB_19_181_Rulemaking_Update_20190821_rev.pdf [perma.cc/GU3U-4ZAJ].
54. Ratliff, *supra* note 2.

12. Evaluating safety management protocols and addressing liability seeking compensation as to historic spills.[55]

Emphasizing the restructuring of the traditional state-local relationship, the most significant change is the incorporation of siting authority in the Act, especially in the permitting process. Previously, local regulation was restricted as set forth in *Bowen/Edwards*.[56] There also exists a new emphasis on evaluating the appropriate parameters of drilling and spacing units.[57]

There will also be the incorporation of cumulative impacts into the COGCC permitting process, consistent with C.R.S. § 34-60-106(11)(c)(II).

VIII. THE FUTURE OF SENATE BILL 181

The ultimate results of Senate Bill 181 are still not known. Those aligned against the oil and gas industry had hoped that Jeffery Robinson, the Director of the COGCC, would have as of Fall 2019 more significantly implemented Senate Bill 181. Aggressive anti-industry sentiment does not appear to be yet observed. As stated by Governor Polis at the time Senate Bill 181 was signed: "This is an important step for the stability of Colorado, to end the oil and gas wars in a way that everyone wins."[58]

Consistent with Senate Bill 181, there have been identified sixteen "objective criteria" so as to guide the rule-making process. It has been represented that the sixteen "objective criteria" would maintain the status quo until new regulations enacting Senate Bill 181 could be approved. Since the passage of Senate Bill 181, over 450 wells have been drilled in Colorado.[59] A total of 1,500 permits for oil and gas drilling have been approved since Governor Polis was sworn

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55. S.B. 181, 72d Gen. Assemb., Reg. Sess. (Colo. 2019).
56. Bd. of Cty. Comm'rs v. Bowen/Edward Assocs., Inc., 830 P.2d 1045, 1059 (Colo. 1992); *see also* COLO. REV. STAT. § 34-60-106(1)(f) (2019).
57. *See* COLO. REV. STAT. ANN. § 34-60-116 (2019).
58. Phillip Doe, *The Bad News about SB 181*, BOULDER WKLY., (Aug. 29, 2019), https://www.boulderweekly.com/news/the-bad-news-about-sb-181/ [https://perma.cc/Y26W-NN6D].
59. *Id.*

in.[60] The drilling of new oil and gas wells has physically moved from more densely populated areas to areas of less population in many instances.

Controversial issues such as setbacks remain unresolved. Currently, Director Robins has enacted 1,500-foot setbacks, a distance short of the 2,500 feet suggested by Proposition 112.[61] A different issue of concern has been the amount of financial assurance required of operators. Financial assurance and bonding are the financial vehicles to guarantee that Operators can pay the cost of protecting the public from wells not plugged and abandoned in compliance with state law.[62] Traditionally, there have been complaints that bending and adequate assurance have been underfunded.

Ultimately, no one knows that end result of regulation to be enacted as a result of Senate Bill 181. The result of the inevitable litigation is even less known.

IX. FINAL COMMENT

What does this evolution of oil and gas regulation in Colorado mean? It is very hard to say. In Colorado, the oil and gas industry creates over $600 million in tax revenue annually.[63] Much of this tax money funds public education. Furthermore, a cornerstone of the domestic economy of the United States, not to mention the global economy, is predicated upon readily available energy that can be purchased at an affordable price. The reality is that there currently exists no credible formula for providing adequate energy, either domestically or globally, in light of a growing population and growing demand for energy that does not significantly include oil and gas. As a result, there exists significant real-life parameters that require critical thinking. Clean energy alone based on current technology and the preservation of our economy without destroying local, state, domestic, and global economies cannot be reasonably anticipated to provide the

60. *Id.*
61. *Id.*
62. *Id.*
63. *Oil and Gas Generates More than $600 Million Per Year in Revenue for K-12 and Higher Education,* COLO. PETROLEUM ASS'N (Jan. 29, 2019), http://www.coloradopetroleumassociation.org/report-oil-and-gas-generates-more-than-600-million-per-year-in-revenue-for-k-12-and-higher-education/ [https://perma.cc/TPC4-KJ96].

adequate supply of energy at a reasonable price. Oil and gas, not to mention coal, remain a significant part of supply so as to meet current and future energy demands. Solving the problem of climate change is the greatest challenge facing the energy industry and society in upcoming decades. The trick is how to provide plentiful and affordable energy that solves critical climate change issues in such a way that does not destroy domestic or global economies.

Ultimately, this shift in local regulation of the oil and gas industry should not be even remotely unexpected. As this Article began, a burgeoning Colorado population observed at the same time as a growing oil and gas industry resulted in a conflict between new populations that were inhabiting the same areas where the oil and gas industry was now drilling. Attempting to harmonize these concurrent uses and, more importantly, the inevitable conflict resulting from each increasingly occupying the same geographical area is a challenge. It is probably not enough to merely come to conclusions as to whether or not the historic regulation of the oil and gas industry was any better or worse than what can be expected in the future. Quite frankly, no system is perfect. As to what transpires in the future, no one can really say.

Nonetheless, the movement away from preemption observed in Colorado to one of local regulation is probably going to be repeated elsewhere. In states where one observes an increase in population along with a less tolerant acceptance of traditional oil and gas industry practices, regulation of the industry moving from state to local control is probably inevitable. Whether or not this change is of benefit in reconciling issues as to climate change and population development with that of energy availability and cost, that result probably is going to be dependent upon the wisdom of our local and statewide politicians.

KANSAS

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I. INTRODUCTION

2019 provided no shortage of excitement, as there were more oil and gas opinions issued by the Kansas Supreme Court than in a usual year.[1] These cases will be the main focus of this Survey, as there

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1. *See* N. Nat. Gas Co. v. Oneok Field Servs. Co., 448 P.3d 383 (Kan. 2019); Jason Oil Co. v. Littler, 446 P.3d 1058 (Kan. 2019); Oxy USA Inc. v. Red Wing Oil, L.L.C., 442 P.3d 504 (Kan. 2019).

are no major legislative developments to report for this year. The first case decided whether the common-law rule against perpetuities should be applied to exceptions of defeasible term mineral interests.[2] The second case is "yet another round in [a] high-dollar subsurface prize fight" about who has the right to gas that has escaped from an underground natural gas storage facility.[3] The third case analyzes whether the misappropriation of royalty payments gives rise to a claim of adverse possession.[4] Additionally, the Kansas Court of Appeals released an oil and gas opinion, which will be briefly discussed.[5]

II. JASON OIL CO. V. LITTLER

In *Jason Oil Co. v. Littler*, the court had to determine whether an exception of a defeasible term mineral interest violates the common-law rule against perpetuities.[6] Generally, an exception of a defeasible term mineral interest includes the grantor conveying the surface estate to the grantee but reserving the mineral interest for a term of years "and so long thereafter as oil and gas is produced."[7] These types of exceptions create a springing executory future interest in the grantee.[8] The springing executory interest could theoretically vest whenever, consequently, it violates the famous Rule Against Perpetuities.[9] Applying the Rule to this type of interest produces a counter-

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2. *Jason Oil Co.*, 446 P. 3d at 1059.

3. *N. Nat. Gas Co.*, 448 P.3d at 386. This series of litigation has spanned over a decade and involved multiple cases in various courts. *See* David E. Pierce, *Kansas*, 2 TEX. A&M L. REV. 81, 82–87 (Spring 2015).

4. *Oxy USA Inc.*, 442 P.3d at 508.

5. Lario Oil & Gas Co. v. Kan. Corp. Comm'n, No. 120,121, 2019 WL 3977825 (Kan. Ct. App. Aug 23, 2019).

6. *Jason Oil Co.*, 446 P.3d at 1059.

7. THOMPSON ON REAL PROPERTY, SECOND THOMAS EDITION § 49.13(f) (David A. Thomas, ed., 2003). For example, the exception of the defeasible term mineral interest at issue in *Jason Oil Co.* read "EXCEPT AND SUBJECT TO: Grantor saves and excepts all oil, gas and other minerals in and under or that may be produced from said land for a period of 20 years or as long thereafter as oil and/or gas and/or other minerals may be produced therefrom and thereunder." *Jason Oil Co.*, 446 P.3d at 1060.

8. David E. Pierce, *Kansas – Oil & Gas*, MIN. L. NEWSL. (Rocky Mountain Min. L. Found., Westminister, CO), Number 3, 2019, at 11.

9. THOMPSON ON REAL PROPERTY, *supra* note 7, at § 49.13(f). A different outcome would exist, however, if a *grant* of a defeasible term mineral interest was

intuitive result, as the grantor would then own the mineral interest outright.[10]

The first step for the court was to classify exactly what type of future interest was at issue in the case.[11] A handful of other states have looked at this issue, and the court noted some of these jurisdictions have twisted common-law property rules and classifications to avoid applying the Rule to these exceptions.[12] Instead of doing this, the court decided to call a spade a spade and recognized the future interest at issue in the case is a springing executory interest.[13] Thus, the next question for the court was whether it wanted to carve out a narrow exception to the common-law rule against perpetuities for exceptions of defeasible term mineral interests.[14] If not, the Rule would invalidate the future interest.[15]

To determine if it should carve out a narrow exception to the common-law Rule, the court focused on the public policy behind the Rule.[16] The court articulated that in Kansas, the clear policy behind the Rule is ensuring the alienability of property and next examined whether applying the Rule to reservations of defeasible term mineral interests would promote the alienability of property.[17] The court held that defeasible term mineral interests actually *promote* the alienability of property, not hinder it.[18] This is because applying the Rule in this instance would keep the surface and mineral estates split, which would increase the difficulty for a potential buyer who wants to buy the entire property.[19] The potential buyer would be able to not only negotiate with the surface estate owner, but they would also have to locate and negotiate with every heir who had received a portion of the mineral

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involved instead of an exception. *Id.* In this situation, the grantor would maintain a possibility of reverter which is not subject to the Rule Against Perpetuities. *Id.*

10. Pierce, *supra* note 8, at 11.

11. *Jason Oil Co.*, 446 P.3d at 1063.

12. *Id.* at 1064–65. The court also mentions that this same analysis would be employed for the reservation of a defeasible term mineral interest in addition to an exception. *Id.* at 1065.

13. *Id.* at 1065.

14. *Id.*

15. *Id.*

16. *Id.* at 1065–66.

17. *Id.* at 1066–67; Pierce, *supra* note 8, at 11.

18. *Jason Oil Co.*, 446 P.3d at 1066–67.

19. *Id.*

estate, even where there was no longer production of oil and gas on the property.[20]

The court also relied on the reasoning of the Williams & Myers treatise, quoting:

> [D]efeasible term interests serve a useful social purpose, whether reserved or granted. The term interest, as compared with a perpetual interest, tends to remove title complications when the land is no longer productive of oil or gas. This simplification of title promotes alienability of land, which is one purpose served by the Rule against Perpetuities. We believe, therefore, that the courts should simply exempt interests following granted or reserved defeasible term interests from the Rule, on the straightforward basis that they serve social and commercial convenience and do not offend the policy of the Rule Against Perpetuities.[21]

The court ultimately held exceptions of defeasible term mineral interests are "ingrained in the oil and gas industry" and furthers the Rule's purpose as opposed to inhibiting it.[22] Thus, the court decided not to apply the Rule in this situation because "[a]pplying the Rule here would be counterproductive to the purpose behind the Rule and create chaos."[23]

This case has the potential to impact areas of law beyond oil and gas.[24] As Professor David E. Pierce notes, "litigants should be able to use the court's analysis to avoid the Rule in other oil and gas and non-oil and gas contexts."[25] Thus, it remains to be seen just how far Kansas courts are willing to temper the once-rigid Rule.

III. NORTHERN NATURAL GAS CO. V. ONEOK (ONEOK II)

20. *Id.*
21. *Id.* at 1067 (citing 2 Williams & Meyers, Oil and Gas Law, § 335 (2018)).
22. *Id*. at 1068.
23. *Id.*
24. Pierce, *supra* note 8, at 11–12.
25. *Id.*

Those familiar with Kansas oil and gas law have most likely heard of the *Northern Natural Gas Co. v. ONEOK* underground storage litigation, which has already lasted over a decade.[26] 2019 provided yet another chapter in this long-lasting saga.[27] A full recap of this series of cases could last pages, so this Survey will attempt to remain focused on the takeaways from the most recent case.[28]

In this case, the precise issue was whether a public utility receiving a certificate from the Federal Energy Regulatory Commission or the Kansas Corporation Commission impairs the right of operators in a reservoir to produce non-native natural gas injected by the public utility into an underground storage field.[29] To answer this question, the court had to walk through the history of Kansas underground natural gas storage law.[30] The court first revisited its holding in *Anderson v. Beech Aircraft Corp.*,[31] which was when non-native gas is injected into a common pool by an entity that is not a public utility, the gas is subject to the rule of capture.[32] Thus, other operators in the pool can produce non-native gas without legal consequences.[33]

Whereas *Anderson* didn't involve a public utility, *Union Gas System, Inc. v. Carnahan* did.[34] The court in *Union Gas* had to determine who has ownership of migratory non-native gas injected into an underground storage facility by a public utility both before and after the public utility receives a certificate of authority for that area.[35] The court held that the migrated non-native gas that was produced before the public utility received certification for underground storage was subject to the *Anderson* rule.[36] Consequently, operators were able to

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26. N. Nat. Gas Co. v. Oneok Field Servs. Co., 448 P.3d 383, 386 (Kan. 2019).

27. *Id.*

28. *See* Pierce, *supra* note 3, at 82–87 for a more robust discussion of the cases involved in this litigation.

29. *N. Nat. Gas. Co.*, 448 P.3d at 385–87.

30. *See id.* at 388.

31. *Id.* at 389. *See* Anderson v. Beech Aircraft Corp. 699 P.2d 1023 (Kan. 1985).

32. *N. Nat. Gas Co.*, 448 P.3d at 391.

33. *Id.*

34. Union Gas Sys., Inc. v. Carnahan, 774 P.2d 962, 964 (Kan. 1989).

35. *N. Nat. Gas Co.*, 448 P.3d at 391–92.

36. *Union Gas Sys., Inc.*, 774 P.2d at 967.

produce this gas and sell it legally until the public utility got a certificate of authority to store gas in the area.[37]

The *Union Gas* court reached a different result, however, for the migrated gas after the public utility received a certificate of authority to condemn the property for storage of natural gas.[38] The court held once a certificate of authority to condemn more of the reservoir is issued, the migrated gas is no longer subject to the rule of capture inside the certificated area.[39] Thus, title to the migrated non-native gas taken from the storage field's certificated boundaries remains in the public utility as long as it is identifiable.[40]

The *Northern Natural Gas Co.* court recognized that due to the similarities between its case and *Union Gas*, if *Union Gas* is still good law, it controls the outcome.[41] The court outlined three potential arguments for why *Union Gas* may no longer be good law which were: (1) it was superseded by K.S.A.55-1210; (2) it was overruled by *Northern Natural Gas Co. v. Martin, Pringle*;[42] and (3) it results in an unconstitutional taking of property.[43] The court, however, dismissed all three of these arguments and held *Union Gas* is still good law in this particular circumstance.[44]

In 1993, K.S.A. 55-1210 was passed as a result of the underground gas storage battles being waged in Kansas.[45] The section of the statute relevant to this case reads:

> With regard to natural gas that has migrated to adjoining property or to a stratum, or portion thereof, which has not been condemned as allowed by law or otherwise purchased: The injector, such injector's heirs, successors and assigns shall not lose title to or possession of such gas if such injector, such injector's heirs,

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37. *Id.*

38. *Id.* at 968.

39. *Id.*

40. *Id.*

41. N. Nat. Gas Co. v. Oneok Field Servs. Co., 448 P.3d 383, 394 (Kan. 2019)

42. *See* N. Nat. Gas Co. v. Martin, Pringle, Oliver, Wallace & Bauer, LLP, 217 P.3d 966 (Kan. 2009)..

43. *N. Nat. Gas Co.*, 448 P.3d at 395.

44. *Id.*

45. *See* Pierce, *supra* note 3, at 83.

> successors or assigns can prove by a preponderance of the evidence that such gas was originally injected into the underground storage.[46]

In *Northern Natural Gas Co. v. ONEOK Field Services Co. (ONEOK I)*, the court held the statute did not completely preempt the field, meaning prior case law in the area is still good law in situations the statute does not directly address.[47] Relying on this, the court in the current case held that *Union Gas* is still good law in circumstances K.S.A. 55-1210 does not specifically address.[48] Such situations include, "how the common-law rule of capture operates during the time *between* certificate issuance and storage rights acquisition," which was what was at issue in this case.[49]

The next argument for *Union Gas* no longer being good law is that it was overruled by *Northern Natural Gas Co. v. Martin, Pringle*.[50] This argument is based on language from *Martin, Pringle*, which stated landowners adjoining natural gas storage areas can continue to capture non-native gas that has migrated onto their property until the public utility "obtained a certificate to expand its storage area onto their land and paid them for that privilege through a condemnation action."[51] This standard created an extra requirement for *Union Gas* in that the public utility has to *pay* landowners for the right to store the gas beneath their property before the rule of capture is turned off.[52] The court here disposed of the extra requirement by saying it was just dicta, as the court in *Martin, Pringle* neither explicitly stated it was overruling *Union Gas* or gave any analysis of why it added the extra requirement.[53] Thus, *Union Gas* remains good law.[54]

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46. KAN. STAT. ANN. § 55-1210(c)(1) (2005).
47. N. Nat. Gas Co. v. Oneok Field Servs. Co. (ONEOK I), 296 P.3d 1106, 1125 (Kan. 2013).
48. *N. Nat. Gas Co.*, 448 P.3d at 395.
49. *Id.* at 396.
50. *Id.*
51. N. Nat. Gas Co. v. Martin, Pringle, Wallace, & Bauer, L.L.P, 217 P.3d 966, 976. Essentially, this standard would allow gas to be taken from the certificated area until actual condemnation occurs. *N. Nat. Gas Co.*, 448 P.3d at 396.
52. *Id.*
53. *Id.* at 396-97.
54. *Id.* at 397.

Finally, the court shut down the argument that *Union Gas* constitutes an unconstitutional taking of property.[55] In short, the court articulated the rule of capture only gives an operator the right to produce gas, and it does not give the operator the right to the gas itself.[56] Therefore, no taking occurs when operators are no longer able to capture gas in a certificated area.[57]

All in all, the court held that *Union Gas* is still good law in certain contexts and its holding controlled in this case.[58] To reiterate, *Union Gas* established others cannot capture an injector's migrated gas "after a natural gas public utility obtains certificated authority to use a storage area and its gas within that area is identifiable"[59]

IV. OXY USA INC. V. RED WING OIL, LLC

Oxy USA Inc. v. Red Wing Oil, LLC involved the question of whether the improper receipt of royalties can give rise to a claim for adverse possession.[60] The facts in *Oxy* revolve around the reservation of a defeasible term mineral interest which expired in 1972.[61] From 1972 to 2009, royalties were paid to the wrong group of owners.[62] The operator continued to pay royalties to those who obtained the grantor's interest, even though it was extinguished in 1972 when the surface and mineral estates were reunited.[63] Thus, the question in the case was do these years of improper royalties prevent the owner of the grantee's interest from enforcing her rights now due to adverse possession?[64] The Kansas Supreme Court said no.[65]

55. *Id.* at 398–99.
56. *Id.* at 399.
57. *Id.*
58. *Id.* at 400.
59. *Id.*
60. Oxy USA Inc. v. Red Wing Oil, LLC, 442 P.3d 504, 505 (Kan. 2019).
61. *Id.* at 506.
62. *Id.* The reason royalties were still being paid after the defeasible term mineral interest ended in 1972 is because the oil and gas lease on the property was unitized with leases on surrounding property, however, a well was not actually drilled on the quarter section of at land at issue in this case until 2009. Oxy USA, Inc. v. Red Wing Oil, LLC, 360 P.3d 457, 459–60 (Kan. Ct. App. 2015).
63. *Oxy USA Inc.*, 442 P.3d at 506.
64. *Id.*
65. *Id.* at 505.

While the court started by recognizing it is possible to adversely possess minerals, it quickly disposed of the argument that was what happened here.[66] The court stated "[a] royalty represents a portion of the value of minerals *after* production."[67] "Thus, being in open, exclusive, and continuous possession of a royalty can never suffice to establish an adverse claim over minerals *in place*."[68] The court called the misappropriation of royalties a conversion "akin to tapping a pipeline and diverting its flow."[69] In order to actually adversely possess the minerals, the attempted adverse possessor would have had to do something to work the mineral estate.[70] Thus, the mineral estate was quieted in favor of the fee owner who had inherited the original grantee's interest.[71]

V. LARIO OIL & GAS CO. V. KANSAS CORPORATION COMM'N

Lario Oil & Gas Co. v. Kansas Corporation Comm'n is a Kansas Court of Appeals case that centers around a large fight to unitize a geological formation. However, it will only be discussed very briefly because it adds very little new to Kansas law.[72]

In short terms, unitization is the combining of oil and gas leases in a pool to operate them as a single unit.[73] In order for a reservoir to qualify as a pool under the Kansas unitization statutes, the reservoir must be a single pressure system.[74] In *Lario*, the party in favor of unitization argued that pools near the end of their economic life and pools not near the end of their economic life should have a "different standard for pressure communication."[75] The court shut this argument down, however, stating "[a]ll units, regardless of their economic

66. *Id.* at 508.
67. *Id.*
68. *Id.*
69. *Id.*
70. *Id.* (citing 1 KUNTZ, LAW OF OIL & GAS § 10.5 (1987)).
71. *Id.*
72. Lario Oil & Gas Co. v. Kan. Corp. Comm'n, No. 120,121, 2019 WL 3977825, at *1 (Kan. Ct. App. Aug 23, 2019).
73. *Id.* at *2.
74. KAN. STAT. ANN. § 55-1302(b) (2018).
75. *Lario Oil & Gas Co.*, 2019 WL 3977825, at *9.

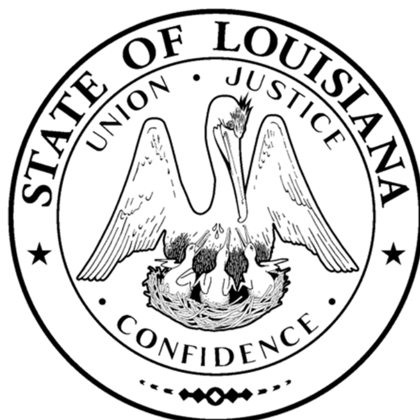
conditions, must be single-pressure systems according to K.S.A. 55-1302(b)."[76]

VI. CONCLUSION

This reporting period provided plenty of excitement for those interested in Kansas oil and gas law. Once again, a few of the main takeaways are: (1) the common-law Rule Against Perpetuities does not apply to exceptions of defeasible term mineral interests; (2) *Union Gas* is still good law in certain contexts, and the rule of capture "does not apply after a natural gas public utility obtains certificated authority to use a storage area and its gas within that area is identifiable;"[77] and (3) the misappropriation of royalties does not give rise to a claim of adverse possession.

76. *Id.*

77. N. Nat. Gas Co. v. Oneok Field Servs. Co., 448 P.3d 383, 406 (Kan. 2019).



LOUISIANA

Keith B. Hall†

I. CASES

A. *Use of Citizen Suits to Pursue Legacy Litigation*[1]

In *Guilbeau v. BEPCO, L.P.*,[2] a landowner filed suit seeking remediation of contamination arising from oil and gas activities prior

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1. In Marin v. Exxon Mobil Corp., 48 So.3d 234, 238 n.1 (La. 2010), the Louisiana Supreme Court stated: "Legacy litigation" refers to lawsuits in which "Legacy litigation" refers to hundreds of cases filed by landowners seeking damages from oil and gas exploration companies for alleged environmental damage in the wake of this Court's decision in Corbello v. Iowa Production, 850 So.2d 686 (La. 2003). These types of actions are known as "legacy litigation" because they often arise from operations conducted many decades ago, leaving an unwanted "legacy" in the form of actual or alleged contamination. (citing Loulan Pitre, Jr., *"Legacy Litigation" and Act 312 of 2006*, 20 TUL. ENVT. L.J. 347, 34 (Summer 2007)).

2. Guilbeau v. BEPCO, L.P., 2019 WL 1230944 (W.D. La.).

to his purchase of the property. The landowner previously had filed a suit seeking a clean-up based on the defendants' obligations under the Louisiana Mineral Code. That earlier suit was dismissed based on the subsequent purchaser doctrine.[3] The subsequent purchaser doctrine states that private claims for damages to property belong to the person who owned the property at the time of the damages and absent that person's assignment of his claims to a subsequent purchaser of the property, the subsequent purchaser does not have a claim against the person who caused the damages.[4]

In the current suit, the landowner seeks injunctive relief—in particular, an order requiring a remediation—in a citizen suit brought pursuant to Louisiana Revised Statutes 30:14 and 30:16. Revised Statute 30:14 states in part:

> Whenever it appears that a person is violating or is threatening to violate a law of this state with respect to the conservation of oil or gas, or both, or a provision of this Chapter, or a rule, regulation, or order made thereunder, the commissioner shall bring suit to restrain that person from continuing the violation or from carrying out the threat.
>
> ***
>
> In this suit, the commissioner may obtain injunctions, prohibitory and mandatory, including temporary restraining orders and preliminary injunctions, as the facts warrant ***

Louisiana Revised Statute 30:16 states:

> If the commissioner fails to bring suit within ten days to restrain a violation as provided in La. R.S. 30:14, any person in interest adversely affected by the violation who has notified the commissioner in writing

3. Guilbeau v. 2 Hess Corp., Inc., 854 F.3d 310, 314 (5th Cir. 2017).

4. Eagle Pipe & Supply, Inc. v. Amerada Hess Corp., 79 So.3d 246 (La. 2011) (the leading case on the subsequent purchaser doctrine). If the damage was apparent at the time of sale, the purchaser presumably negotiated for a lower sales price. *Eagle Pipe*, So. 3d at 275 ("it is assumed the apparent damage would result in a loss of value to the sale, the subsequent purchaser may have a claim in redhibition against the seller.").

> of the violation or threat thereof and has requested the commissioner to sue, may bring suit to prevent any or further violations, in the district court of any parish in which the commissioner could have brought suit. If the court holds that injunctive relief should be granted, the commissioner shall be made a party and shall be substituted for the person who brought the suit and the injunction shall be issued as if the commissioner had at all times been the complaining party.

The defendants filed motions to dismiss pursuant to Federal Rule of Civil Procedure 12(b)(6), arguing that these citizen suit provisions are designed only to combat ongoing and threatened violations of the conservation laws, not to provide a remedy for past violations. Magistrate Judge Perez-Montes issued a report rejecting that argument and recommending that the court deny the motions to dismiss. In his report, he relied in part on the Louisiana First Circuit's decision in *Global Marketing Solutions, L.L.C. v. Blue Mill Farms, Inc.*[5] In addition, the Magistrate's report cited a footnote in the Louisiana Supreme Court's opinion in *Marin v. Exxon Mobil Corp.* In that footnote, the Court stated in dicta:

> We note that one of the reasons we granted this writ was to determine whether a subsequent purchaser has the right to sue for property damages that occurred before he purchased the property, particularly where the damage was not overt. However, we need not reach that determination in this case because, assuming the Breauxs had a right as a subsequent purchaser to sue in tort for property damage, that right has prescribed. Further, we note that regardless of who has standing to pursue claims for money damages, the current owner of property always has the right to seek a regulatory cleanup of a contaminated site. La. R.S. 30:6(F); La. R.S. 30:16.[6]

5. Global Marketing Solutions, L.L.C. v. Blue Mill Farms, Inc., 2018-0093 (La. App. 1 Cir. 11/6/2018), 2018 WL 5816971. That decision, by a divided First Circuit panel, denied the defendants' exception of no cause of action.

6. *Marin*, 48 So.3d at 256 n. 18.

Tureau v. BEPCO, L.P.[7] is almost identical to *Guilbeau*, which is discussed immediately above. In *Tureau*, a landowner filed suit seeking remediation of contamination arising from oil and gas activities prior to his purchase of the property. The landowner previously had filed a suit seeking a clean-up based on the defendants' obligations under the Louisiana Mineral Code. That earlier suit was dismissed based on the subsequent purchaser doctrine.[8] In the current action, the landowner seeks injunctive relief—an order requiring a remediation—in a citizen suit brought pursuant to Louisiana Revised Statutes 30:14 and 30:16. The defendants filed motions to dismiss pursuant to Federal Rule of Civil Procedure 12(b)(6), arguing that these citizen suit provisions are designed only to combat ongoing and threatened violations of the conservation laws, not as a remedy for past violations. Magistrate Judge Perez-Montes issued a report rejecting that argument and recommending that the court deny the motions to dismiss.

B. *Lease Royalty Dispute*

1. Lease Basing Royalties on Market Value at the Well, While Making Lessee Responsible for Most Production Costs, was Ambiguous

In *AWT Be Good LLC v. Chesapeake, L.P.*,[9] AWT Be Good LLC granted an oil and gas lease, which provided that except when natural gas was sold at the well, the royalty on gas would be based on the market value at the well. A few months later, the lease was assigned to Chesapeake Louisiana. In 2010, the parties amended the lease. The amendment provided that the lessee would be responsible for many post-production costs but not "long-haul transportation charges to the point of sale of the royalty gas." Later, AWT brought suit, asserting that Chesapeake was improperly charging AWT with a

7. Tureau v. BEPCO, L.P., 2019 WL 1230976 (W.D. La.)
8. Tureau v. 2 H, Inc., 2016 WL 4500755 (W.D. La. 2016).
9. AWT Be Good LLC v. Chesapeake, L.P., 2019 WL 177946 (W.D. La. 2019).

portion of pipeline capacity charges when Chesapeake did not use the entire pipeline capacity that it reserved.

Both sides moved for summary judgment, but the court held that neither side was entitled to summary judgment. The court concluded that the lease was ambiguous for multiple reasons. For example, the lease did not make it clear what constituted "long-haul transportation charges." Further, the parties had amended the lease to make the lessee responsible for many types of post-production costs, but the parties had not amended the portion of the royalty clause that provided that the royalty on gas will be based on the market value at the well, even though "market value at the well" implies that the parties will each bear a share of post-production costs. Additionally, neither party has submitted summary judgment evidence sufficient to make it clear exactly how Chesapeake's contracts with the pipeline companies worked or how Chesapeake determined the amount of capacity charge that would be allocated to AWT.

2. Letters Informing Lessees of Change in Lessor and Requesting Reissuance of Past Royalty Checks were Not Sufficient to Constitute a Mineral Code article 137 Notice

Louisiana Oil & Gas Interests, LLC v. Shell Trading (U.S.) Co.[10] was a royalty dispute. Properties-General LLC owned the lessor's interest under an oil and gas lease held by Shell Trading and Gulfport Energy. Properties-General transferred its interest to Louisiana Oil & Gas Interests, LLC in late December 2013.

On January 17, 2014, Louisiana Oil & Gas sent a letter to Shell requesting that future royalty checks be made payable to it. Within a few days, Shell responded with an email requesting that Louisiana Oil & Gas provide Shell with a copy of a recorded document in which Properties-General transferred its interest to Louisiana Oil & Gas.

On February 21, 2014, Louisiana Oil & Gas recorded a copy of the document effecting the transfer into the conveyance records of Cameron Parish, but months went by without Louisiana Oil & Gas sending a copy of the document to Shell. Shell continued to issue royalty checks made out to Properties-General. According to

10. Louisiana Oil & Gas Interests, LLC v. Shell Trading (U.S.) Co., 2019 WL 1768296 (W.D. La.).

Louisiana Oil & Gas, it shared an owner with Properties-General, and for a while, Louisiana Oil & Gas's bank had allowed the company to deposit the checks, even though the checks were made out to a separate company. However, Louisiana Oil & Gas later changed banks, and the new bank would not let the company deposit the checks.

On April 21, 2015, Louisiana Oil & Gas faxed to Shell a certified copy of the document transferring the interest and showing that the document had been filed in the conveyance records.

On April 23, 2015, Louisiana Oil & Gas returned to Shell two checks that were made out to Properties-General. Louisiana Oil & Gas requested that the two checks be reissued to it. Each of the checks was dated prior to the April 21 fax.

On June 1, 2015, Shell reissued the two checks.

On September 1, 2015, Louisiana Oil & Gas sent a demand to Shell requesting payment of damages pursuant to Louisiana Mineral Code article 31:140.

Shell and Gulfport filed Rule 12(b)(6) motions to dismiss, and Magistrate Judge Kathleen Kay issued a report recommending that the motions be granted. She noted that under Mineral Code article 137, before a lessor asserts a claim for the underpayment, nonpayment, or late payment of royalties, the lessor must give the lessee written notice of such failure and wait thirty days. The remedy for which a lessor who brings suit and proves he was not properly paid depends on the lessee's response to the required written notice that the lessee has not properly paid royalties.

Here, the January 17, 2014 letter could not constitute a notice of failure to properly pay royalties because the letter addressed future royalties, not past royalties that had not been timely and properly paid. Further, the plaintiff's April 23, 2015 fax did not actually allege that royalties had not been properly and timely paid. The letter requested that the checks be reissued, but that request fell short of an assertion that the royalties had not been properly paid. Accordingly, Louisiana Oil & Gas never sent a Mineral Code article 137 demand before Shell paid the royalties with its June 1, 2015 check.

C. *Meaning of "minerals" in Instrument Creating Servitude—Servitude that Applied to "all forms of minerals" Applied to Clay*

In *Citrus Realty, LLC v. Parker*,[11] the defendants owned an undivided 10% in certain land in Plaquemines Parish. They sold their 10% ownership interest to Citrus but reserved a mineral servitude. The act of sale reserved the defendants' rights relating to "all forms of minerals, including oil gas" but provided that the defendants would have no surface use rights. However, they could "explore for minerals by offsite directional drilling or other means not involving the surface of the property." White Oak Realty later acquired ownership of the 90% interest in the land not owned by Citrus.

White Oak and Citrus later began to conduct clay mining operations on the land. The defendants asserted their right to a portion of the proceeds, pursuant to their servitude for 10% of all minerals. Citrus filed an action for a declaratory judgment that the defendants' servitude did not extend to the clay. White Oak later joined the suit as an additional plaintiff.

The plaintiffs argued that the language in the act of sale that barred the defendants from using the surface was intended to limit the servitude to minerals that can be produced by directional drilling. The district court granted summary judgment in favor of the plaintiffs, and the defendants appealed. The appellate court reversed, rejecting the argument that the restriction on surface use also had the effect of limiting the minerals to which the servitude applied. The appellate court reasoned that the reservation of a right to "all forms of minerals" applied to clay.

The appellate court also noted that certain additional justifications given by the trial court for its judgment in favor of the plaintiffs were simply erroneous. For example, the trial court had reasoned that because prescription of nonuse is only interrupted by operations conducted by the servitude owner or someone operating on the servitude owner's behalf, a servitude owner is not entitled to a share of production from someone else's operations. This is clearly wrong. As noted by the appellate court, the provision in the Mineral Code that prescription of nonuse is only interrupted by operations conducted by the servitude owner (or someone operating on his behalf)[12] has no bearing on the servitude owner's right to a share of production.

11. Citrus Realty, LLC v. Parker, 2018-516 (La. App. 4 Cir. 1/30/2019), 2019 WL 385194 (La. App. 4th Cir. 2019).

12. LA. STAT. ANN. § 31:42 (2000) ("Except as provided in Articles 44 through

Therefore, the appellate court reversed the summary judgment granted in favor of the plaintiffs and remanded the case to the district court.

D. *Louisiana Oil Well Lien Act Does Not Create Personal Obligation*

In *Quality Production Management, LLC v. ConocoPhillips Co.*,[13] Quality Production Management filed suit against ConocoPhillips and BHP Billiton Petroleum. Quality alleged that ConocoPhillips and BHP are the owners of certain wells off the coast of Vermilion Parish. At the request of Rooster Petroleum, the operator of record for the wells, Quality performed work and provided materials for which it was owed about $90,525.71, along with interest and reasonable attorneys fees, but Rooster went into bankruptcy. Quality asserted a privilege, pursuant to the Louisiana Oil Well Lien Act ("LOWLA")[14] and sought a money judgment against ConocoPhillips and BHP. Those defendants moved to dismiss the claims for a money judgment against them, asserting that there was no privity of contract between them and Quality, and that LOWLA does not create personal liability. Rather, LOWLA provides in rem liability only against the wells and leases on which a claimant performs work or provides material or equipment. Magistrate Judge Whitehurst agreed and issued a report recommending dismissal of the portion of Quality's claim that seeks to impose personal liability against ConocoPhillips and BHP.

E. *Prescription of Nonuse: Creation of Unit with Shut-In Well Capable of Production in Paying Quantities Interrupts Prescription of Nonuse for Mineral Royalty Even Though Production Test was a Different Type Test Than Necessary to Satisfy Regulations*

52, use of a mineral servitude must be by the owner of the servitude, his representative or employee, or some other person acting on his behalf.") Title 31 of the Louisiana Revised Statutes is known as the "Louisiana Mineral Code." The provisions of the Mineral Code may be cited as "articles" of the Code or as "sections" of Title 31 of the Revised Statutes. LA. STAT. ANN. § 31:1 (2000) ("Thus Article 30 of the Louisiana Mineral Code may also be referred to or cited as R.S. 31:30.").

13. Quality Production Management, LLC v. ConocoPhillips Co., 2019 WL 516125 (W.D. La.).

14. LA. STAT. ANN. § 9:4863 (2007).

George M. Gilmer, Jr. granted a mineral royalty to Regal Energy, L.L.C. covering land in DeSoto Parish on April 1, 2018.[15] The instrument granting the royalty provided that the royalty would be subject to a three-year prescriptive period, but that the presence of a shut-in well would "perpetuate the term" of the royalty.

XTO Energy, Inc. drilled a well (the "Brown Well") on the property and (through an oilfield service company) performed an open-flow surface production test in late January 2009, flaring natural gas during the test. The test showed that the Brown Well was capable of producing gas in paying quantities. The Brown Well became the unit well but was shut-in because of the lack of a pipeline. On April 30, 2011, Chesapeake Operating, Inc. established production from an alternate unit well.

Gilmer filed suit, seeking a declaratory judgment that the mineral royalty had terminated by prescription of nonuse[16] before that production began. Gilmer contended that production from the Brown Well did not interrupt prescription because the hydrocarbons produced during the test of the well were flared, not saved and used. He also noted that production from Chesapeake's alternate well did not start until more than three years after the royalty was created.

Relevant Mineral Code provisions include articles 87, 88, 90, and 91. These provide:

> **Min. Code art. 87. Production as interruption of prescription; commencement of prescription anew**
>
> Prescription of nonuse running against a mineral royalty is interrupted by the production of any mineral covered by the act creating the royalty. Prescription is interrupted on the date on which actual production begins and commences anew from the date of cessation of actual production.

15. Gilmer v. Principle Energy, L.L.C., 52,281 (La. App. 2 Cir. 9/26/2018), 256 So. 3d 1139.

16. LA. CIV. CODE ANN. art. 3448 (2007) (stating that "Prescription of nonuse is a mode of extinction of a real right other than ownership as a result of failure to exercise the right for a period of time."); LA. STAT. ANN. § 31:27 (2000) (listing "prescription resulting from nonuse for ten years" as one mode of extinction for mineral servitudes).

Min. Code art. 88. Saved production sufficient to interrupt prescription

To interrupt prescription it is not necessary that minerals be produced in paying quantities but only that they actually be produced and saved.

Min. Code art. 90. Tested shut-in well as interruption of prescription

When there exists on a tract of land burdened by a mineral royalty, or on a conventional or compulsory unit that includes all or part thereof, a shut-in well proved through testing by surface production to be capable of producing minerals in paying quantities, prescription is interrupted on the date production is obtained by such testing. If only a part of the tract burdened by the royalty is included in a unit and the unit well is on land other than that burdened by the royalty, the interruption of prescription extends only to that portion of the tract burdened by the royalty included in the unit. Prescription commences anew from the date on which the well is shut in after such testing.

Min. Code art. 91. Unitization with tested shut-in well; effect as interruption of prescription

If the land or part thereof, burdened by a mineral royalty is included in a conventional or compulsory unit on which there is a well shut in prior to the creation of the unit, located on other land within the unit, and capable of producing in paying quantities as required by Article 90, prescription is interrupted on and commences anew from the effective date of the order or act creating the unit.

The trial court held that, because production was not saved during the testing of the Brown Well, prescription was not interrupted pursuant to article 90. However, the court held that prescription was

interrupted, pursuant to article 91, when the Brown Well was named the unit well. The district court rejected Gilmer's argument that because XTO had not conducted a type of production test required under Office of Conservation regulations,[17] the production test had not counted for purposes of Mineral Code article 91.

The Louisiana Second Circuit affirmed the district court's summary judgment dismissing Gilmer's suit. The appellate court basically followed the reasoning of the trial, stating its conclusion that because hydrocarbons were not saved during the production test, the test did not interrupt prescription pursuant to Mineral Code articles 87 or 90.[18] On the other hand, pursuant to article 91, "prescription was interrupted on, and commenced anew, from the effective date of the order . . . creating the unit."[19] Like the trial court, the appellate court rejected the plaintiff's contention that the testing of the well did not count for purposes of Mineral Code articles 90 and 91 because of the operator's failure to perform the type of test required by certain regulations.

F. *Mineral Code article 206 Obligation Applies to Person Who Holds Lease at Time It Terminates, Rather Than to All Persons Who Ever Held Lease*

In the early 1970s, the Pardee Company sold several tracts of land to the predecessor of Weyerhaeuser Co.[20] In the sale, Pardee reserved a mineral servitude over each tract. Pardee granted a mineral lease covering portions of the land in 2001. The original lessee assigned the lease to EP Energy E&P Co., which established unit production for units that included portions of the land. Weyerhaeuser filed suit asserting that the servitude at issue had terminated by prescription of nonuse before EP established production. Weyerhaeuser demanded that several parties, including EP, execute a recordable act evidencing termination of their mineral rights. EP declined to do so. Weyerhaeuser filed suit seeking a declaration that

17. One of the regulations governing well testing is LA. ADMIN. CODE tit. 43, pt. XIX, § 119 (West, Westlaw through rules pub. in La. Reg. Vol. 45, No. 09, Sept. 20, 2019).
18. Mineral Code article 90 (LA. STAT. ANN. § 31:90) does not explicitly require that production be saved in order for testing to interrupt prescription.
19. Gilmer v. Principle Energy, 256 So. 3d 1139, 1145 (La. App. 2018).
20. Weyerhaeuser Co. v. Pardee Minerals, LLC, 2018 WL 5624312 (W.D. La.).

the mineral rights had terminated. Weyerhaeuser also sought attorney fees, pursuant to Mineral Code article 206, because of the defendants' failure to acknowledge the termination of their mineral rights. The district court rejected Weyerhaeuser's claim against EP for attorney fees. The court interpreted Mineral Code article 206 as imposing a duty only on the person who owns a mineral right at the time the right terminates, not on all persons who ever owned the mineral interest.

G. *Pooling Issues--Unleased Owner Not Responsible for Post-Production Costs*

In *Johnson v. Chesapeake Louisiana LP*,[21] parties disputed whether the operator of a compulsory drilling unit can charge an unleased owner with a proportionate share of post-production costs. The United States District Court for the Western District of Louisiana held that such an operator cannot.

Louisiana Revised Statute Section 30:10(A)(2) states, "In the event pooling is required, the cost of development and operation of the pooled unit chargeable to the owners therein shall be determined and recovered as provided herein." Section 30:10(A)(3) provides that owners of unleased mineral rights in a tract in a unit are liable, out of production, for their "tract's allocated share of the actual reasonable expenditures" incurred by the unit operator in drilling the well and producing oil or gas. The statute does not expressly address post-production costs that the operator may incur in handling and transporting oil or gas prior to selling it.

Nevertheless, unit operators often incur such post-production costs in handling and arranging the sale of hydrocarbons attributable to unleased interests, particularly if a unit well produces natural gas. This occurs because many owners of unleased interests do not make their own arrangements to sell the portion of gas attributable to the tracts in which they own interests. In such circumstances, the operator has authority to sell the gas attributable to the unleased interests, subject to an obligation to account to the owners of the interests. Typically, operators choose to exercise that authority because the alternative of letting an unleased owner's share of gas accumulate is not practical.

21. Johnson v. Chesapeake Louisiana LP, 2019 WL 1301985 (W.D. La.).

Post-production costs that operators commonly incur include expenses for treating and compressing gas and transporting it to the place of sale. This leads to the question disputed in *Johnson*. Namely, if the unit operator sells natural gas attributable to an unleased interest, is the owner of that interest responsible for a proportionate share of the post-production costs reasonably incurred by the operator in handling the gas? In *Johnson*, the operator (Chesapeake) argued that it was entitled to charge the unleased owner with a proportionate share of these costs. Otherwise, the unleased owners would be unjustly enriched at Chesapeake's expense.

The court rejected that argument, noting that 30:10(A)(3) states:

> If there is included in any unit created by the commissioner of conservation one or more unleased interests for which the party or parties entitled to market production therefrom have not made arrangements to separately dispose of the share of such production attributable to such tract, and the unit operator proceeds with the sale of unit production, then the unit operator shall pay to such party or parties such tract's pro rata share of the proceeds of the sale of production within one hundred eighty days of such sale.

Chesapeake argued that the only purpose of 30:10(A)(3) is to set a deadline for payment, not to govern liability for post-production costs. The court held otherwise. Section 30:10 does not define "pro rata share," but the court concluded that it means a pro rata portion of gross proceeds from which the operator may subtract only the costs that Section 30:10 expressly authorizes the operator to recover. The district court granted summary judgment in favor of the unleased owners, holding that Chesapeake may not charge them with a share of post-production costs.

II. Legislation

A. *Co-ownership and Authority to Operate – La. Acts 2019, No. 350*

When more than one person owns a working interest in the same land, a question sometimes arises regarding what level of consent is needed to authorize oil and gas operations.[22] In other words, do operations require the consent of all persons who own a working interest?

The answer to this question is: "It depends." The existence of multiple working interest owners can arise in various ways. The simplest is when land is co-owned and no mineral servitudes or mineral leases exist. The Mineral Code does not address this situation, but Civil Code article 801 states: "The use and management of the thing held in indivision is determined by agreement of all the co-owners." This has been interpreted as meaning that the consent of all co-owners of the land generally is required in order to authorize operations[23] with a narrow exception being that Civil Code article 800 allows a co-owner to "take necessary steps for the preservation of the thing held in indivision" without the concurrence of other co-owners. Under Mineral Code article 177, a similar rule and similar exception apply if the land is subject to a mineral lease and the lessee's interest is co-owned.

However, different rules apply in three other situations—(1) if the land is subject to a mineral servitude that is co-owned, (2) the land is co-owned and one or more, but fewer than all, of the co-owners grant a mineral servitude, or (3) the land is co-owned or it is subject to a mineral servitude that is co-owned, and one or more (but fewer than all) of the co-owners grant a mineral lease. In these three situations, the original version of the Mineral Code required the consent of all working interest owners, but that requirement has been loosened.[24]

The first "loosening" occurred in 1986. Acts 1986, No. 1047 amended Mineral Code article 164 to provide that if a co-owner of land creates a mineral servitude that burdened his interest, the servitude owner can operate, provided that such owner acquires the consent of co-owners owning at least an undivided 90% interest in the land (the fractional interest of the co-owner who created the servitude

22. Clark v. Tensas Delta Land Co., 136 So. 1, 2 (La. 1931) (owner of mineral servitude for one-half of minerals erroneously contended that it needed consent of landowner); *cf.* Huckabay v. Tex. Co., 78 So. 2d 829 (La. 1955).

23. *Cf.* Gulf Refining Co. v. Carroll, 82 So. 277, 278 (La. 1919); Sun Oil Co. v. State Mineral Bd., 92 So. 2d 583, 586 (La. 1956); LA. STAT. ANN. § 31:177 (2000).

24. LA. STAT. ANN. §§ 31:164, 31:166, 31:175 (2000).

should count toward the total amount of consenting interests). The same legislation amended Mineral Code article 166 to provide that if a co-owner of land creates a mineral lease covering his interest, the lessee may operate with the consent of co-owners owning at least an undivided 90% interest in the land. Finally, the 1986 legislation amended Mineral Code article 175 to provide that if land is subject to a mineral servitude and the mineral servitude itself is co-owned, a co-owner can conduct operations if co-owners owning at least an undivided 90% interest consent.

The requirements were loosened further two years later, when Acts 1988, No. 647 amended Mineral Code articles 164, 166, and 175 to lower the threshold in those three situations from 90% to 80%.

Acts 2019, No. 350 amends Mineral Code articles 164, 166, and 175 to lower the threshold to 75%.

B. *Use of Oilfield Site Restoration Fund for Responding to Emergencies*

Acts 2019, No. 193 amended Louisiana Revised Statute 30:86 to authorize use of money from the Oilfield Site Restoration Fund to respond to emergencies declared by the Commissioner of Conservation pursuant to Revised Statute 30:6.1. Act No. 193 also amends Revised Statue 30:93.1 to provide that if money from the Fund is used to respond to an emergency, the Commissioner must seek recovery of those funds from any party that has operated or held a working interest in the site where the emergency occurs.

C.*State Leases—Including a Provision for a Security Interest*

Acts 2019, No. 403 provides that the State Mineral and Energy Board may include a clause that grants a security interest in minerals produced pursuant to the lease (or lands pooled therewith and attributable to the leased premises) in state mineral leases issued after July 31, 2019 to secure the lessee's obligation to pay lease royalties or other sums due under the lease.

The motivation for this amendment relates to the fact that Louisiana law classifies an oil and gas as a type of lease[25]—in contrast to the laws of some other states, which do not classify oil and gas leases as true leases (as the term "lease" is used in landlord tenant

25. LA. CIV. CODE ANN. art. 2671 (2019).

law).[26] Therefore, a mineral lessor's royalty constitutes rent under Louisiana law.[27] Because the lessor's royalty constitutes rent, the Mineral Code article 146 "lessor's lien," which is designed to secure the payment of the royalty, may be rendered unenforceable by 11 U.S.C. § 545 when a lessee is in bankruptcy.[28] Certain state officials were concerned that Louisiana needed to find a way to secure payment of the royalties to which it is entitled under oil and gas leases granted by the State.[29]

26. Natural Gas Pipeline Co. v. Pool, 124 S.W.3d 188, 192 (Tex. 2003) ("In Texas it has long been recognized that an oil and gas lease is not a 'lease' in the traditional sense of a lease of the surface of real property."); *In re* Topco, 894 F.2d 727, 739 n.17 (5th Cir. 1990) ("The term 'lease,' when used in an oil and gas context, is a misnomer. The estate created by the oil and gas lease is not the same as those interests created under a 'lease' governed by the law of landlord and tenant"); PATRICK H. MARTIN & BRUCE M. KRAMER, WILLIAMS AND MEYERS OIL AND GAS LAW § 202.1 ("The very name 'lease' is unfortunate inasmuch as it tends to give the impression to the uninformed that the relationship arising between the parties to an oil and gas lease is the same as that of landlord and tenant under as [sic] common law lease of land, whereas except in Louisiana, the dissimilarities are more important than the similarities.").

27. LA. STAT. ANN. § 31:123 (2000).

28. *See e.g.*, *In re* WRT Energy Corp., 169 F.3d 306 (5th Cir. 1999).

29. The author served on a committee appointed by the Louisiana Law Institute, at the request of the Louisiana legislature, to address this issue.

MICHIGAN OIL AND GAS UPDATE

William A. Horn and Joshua D. Beard[1]

I. REGULATORY DEVELOPMENT

The Michigan Department of Environment, Great Lakes, and Energy ("EGLE"), formerly the Michigan Department of Environmental Quality,[2]is in the process of seeking primary enforcement responsibility from the United States Environmental

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2. Exec. Order No. 2019-6, *reprinted in* MICH. COMP. LAWS SERV. §324.99923

Protection Agency ("EPA") for its Underground Injection Control ("UIC") program for Class II wells pursuant to Part C of the Safe Drinking Water Act ("SDWA").[3]

The primary purpose of the SDWA is to protect the quality of underground sources of drinking water.[4] The SDWA accomplishes this purpose by prohibiting the injection of fluids underground without a permit.[5] The EPA regulates the injection of fluid underground through UIC programs for various types of injection wells.[6] Class II wells are injection wells used exclusively for the injection of fluids associated with oil and natural gas production (whether for disposal, storage or enhanced recovery).[7] The EPA administers the UIC program for Class II wells, unless a state agency has applied for and received EPA approval for primary enforcement authority. The delegation of the EPA's primary enforcement authority is generally referred to as "primacy."[8]

There are two methods for a state to obtain primacy over Class II wells. A state can demonstrate that its UIC Program meets the EPA's minimum requirements for construction, operation, monitoring, testing, reporting, and closure under Section 1422 of the SDWA.[9] Alternatively, a state can demonstrate that its existing program is equally effective in preventing endangerment of underground sources of drinking water and has adequate permitting, inspection, monitoring, record-keeping and reporting requirements under Section 1425 of the SDWA.[10] EGLE is applying for primacy over Class II injection wells pursuant to Section 1425 of the SDWA.[11]

3. Protection of Underground Sources of Drinking Water, 42 U.S.C. §§ 300h to 300h-8 (2012).

4. *See Summary of the Safe Drinking Water Act*, EPA https://www.epa.gov/laws-regulations/summary-safe-drinking-water-act (last visited Jan. 8, 2020), [https://perma.cc/QV3R-M8D2].

5. § 300h(b)(1)(a).

6. §§ 300h– 300h-8.

7. *See* 40 C.F.R. § 144.6(b) (2011).

8. *See Primary Enforcement Authority for the Underground Injection Control Program*, EPA https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program (lasted visited Jan. 8, 2020), [https://perma.cc/RL5C-YVHU].

9. § 300h(b)(1).

10. § 300h-4(b).

11. *Primary Enforcement Authority for the Underground Injection Control Program*, EPA https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program (lasted visited Jan. 8, 2020), [https://perma.cc/RL5C-YVHU].

During the ongoing Completeness Review of EGLE's primacy application,[12] a determination was made that certain regulatory changes would be necessary to demonstrate to the EPA that the State's program is equally effective at protecting underground sources of drinking water.[13] In particular, Michigan's Oil and Gas Operations rules in effect at the time of initial primacy application limited certain regulatory requirements to "mineral water," which was undefined, and "fresh water," which was more narrowly defined than an "underground source of drinking water" in the EPA rules promulgated pursuant to the SDWA.[14] In addition, the definition of "waste" in the Michigan Oil and Gas Operations rules contained an ambiguity, which could have been construed to imply that EGLE's authority to prevent waste did not arise until after an underground source of drinking water became contaminated.[15]

In response to the EPA's expressed concerns about whether the EGLE's Oil and Gas Operations rules would be equally effective at protecting underground sources of drinking water as the EPA administered UIC program for Class II wells, EGLE proposed Oil and Gas Operations rule revisions to re-define "fresh water" and "waste" and add a new definition for "mineral water."[16] EGLE's proposed rule set was the first rule to be presented to and approved by the new Environmental Rules Committee, which was established in 2018 as an independent body to oversee the rule-making function of EGLE pursuant to Michigan Public Act No. 652 of 2018.[17]

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12. *Id.*

13. *See* MICH. DEP'T OF ENV'T, GREAT LAKES, & ENERGY, AGENCY REPORT TO THE JOINT COMMITTEE ON ADMINISTRATIVE RULES (2019) https://dtmb.state.mi.us/ORRDocs/JCAR/1889_2019-001EG_jcar.pdf.

14. *Compare* MICH. ADMIN. CODE r. 324.102(s) (current version at MICH. ADMIN. CODE r. 324.102(s), amended effective October 18, 2019), which defined "fresh water" as "water that is free of contamination in concentrations that may cause disease or harmful physiological effects and is safe for human consumption, *with* 40 C.F.R. 144.3(a)(2), which, in relevant part, defines an "underground source of drinking water" as containing "fewer than 10,000 mg/l total dissolved solids."

15. MICH. ADMIN. CODE r. 324.801(v) (2019) (defining "waste" as "includ[ing] unreasonable damage to an underground source of drinking water").

16. *See* MICH. DEP'T OF ENV'T, GREAT LAKES, & ENERGY, *supra* note 12.

17. S.B. 652, 99th Leg., Reg. Sess. (Mich. 2018). More details on the establishment, make-up and function of the *Environmental Rules Committee* can be found in *Michigan Legislative Developments*, 5 TEX A&M PROP. L. 39 (2019) *available at* https://law.tamu.edu/docs/default-source/jpl/mi-2019-tamu-jpl-oil-gas-survey-

The new Oil and Gas Operations rules became effective October 18, 2019. Under the new Oil and Gas Operations rules, "fresh water" is now redefined as water containing less than 1,000 milligrams per liter of total dissolved solids[18] and "mineral water" is defined as water containing 1,000 milligrams per liter or more of total dissolved solids.[19] "Waste" is now redefined as including "endangerment to an underground source of drinking water."[20]

EGLE intends these new rules to demonstrate to the EPA that the EGLE Oil and Gas Operations rules unequivocally protect underground sources of drinking water from endangerment and are equally effective as the EPA administered UIC program for Class II wells.[21] Should the EPA concur, approval of EGLE's application for Michigan primacy over Class II wells is in the reasonably foreseeable future.

18. MICH. ADMIN. CODE r. 324.102(s) (2019).
19. MICH. ADMIN. CODE r. 324.102(z) (2019).
20. MICH. ADMIN. CODE r. 324.801(v) (2019).
21. *See* MICH. DEP'T OF ENV'T, GREAT LAKES, & ENERGY, *supra* note 12.

MONTANA

Stephen R. Brown[*]

I. BACKGROUND

In 2018, Montana produced 21.5 million barrels of crude oil and 93.2 million cubic feet of natural gas. Nationally, Montana ranked thirteenth in crude oil production. Through August 2019, crude oil production declined by 587,000 barrels, and natural gas production increased by 5.5 million cubic feet when compared to the same period in 2018.[1]

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1. *See Montana Field Production of Crude Oil*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPMT2&f=M [https://perma.cc/JYT8-EBNK] (last visited Dec. 5, 2019) (displaying the annual crude oil production and the decrease in crude oil production in 2019); *See U.S. natural gas production (gross withdrawals)*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/petroleum/production/#ng-tab [https://perma.cc/N9ZU-M3LV] (follow: tab option on the screen to "Montana") (last visited Dec. 5, 2019) (indicating the increase in natural gas production).

II. MONTANA SUPREME COURT

The Montana Supreme Court only decided one oil and gas case in the last year.

A. *Ferdig Oil Co. v. ROC Gathering, LLC*

Ferdig Oil Co. ("Ferdig") and ROC Gathering, LLP ("ROC") both conduct natural gas operations in north-central Montana. Both companies own natural gas processing facilities. ROC's plant delivers processed gas to Northwestern Energy ("Northwestern"), and Northwestern then transmits processed gas to its customers. Ferdig processes sour gas at its facility. Ferdig transmits processed gas via a pipeline that interconnects with ROC's gas delivery line.

In 2006, Ferdig, ROC, and several related companies entered into a settlement agreement to resolve a variety of ongoing business disputes. The agreement contained provisions allowing Ferdig to tap into the ROC delivery line. In 2010, ROC notified Ferdig that it was terminating the right to tap, claiming that Ferdig was allowing sour gas into the pipeline. Two years later, Ferdig sued seeking a declaration of its rights. Ferdig did not serve the lawsuit until 2014. ROC then filed counterclaims.

Ferdig sought a preliminary injunction to prevent ROC from denying access to its line. When the district court denied the injunction, Ferdig built its own line to connect with Northwestern's line. Ferdig then amended its complaint adding several additional claims. The parties filed cross motions for summary judgment. After the district court ruled in favor of ROC, Ferdig appealed to the Montana Supreme Court.

The Supreme Court appeal focused on whether ROC had improperly added terms to the 2006 settlement agreement by requiring that Ferdig certify the safety of repair work Ferdig had performed to address the sour gas issue. The Court denied the appeal, finding that the request for certification was made after ROC already had alleged in litigation that Ferdig was in breach of the 2006 agreement, and therefore was not an attempt to renegotiate the existing agreement. [2]

2. Ferdig Oil Co. v. ROC Gathering, LLP, 432 P.3d 118 (Mont. 2018).

The Court also upheld most of the contract-based attorney's fees awarded by the district court.

III. Ninth Circuit Court of Appeals

A. *Northern Oil & Gas v. Continental*

On September 29, 2008, Northwest Farm Credit Services ("NWFCS") entered into a five-year primary term oil and gas lease with Diamond Resources, Inc. ("Diamond"). Diamond later assigned the lease to Continental Resources. The lease covered a half section in Richland County, Montana. Diamond and Continental timely paid delay rentals for the first four years.

In September 2013, Continental began drilling operations in an adjacent section. However, the adjacent section was not pooled with the leased parcel until after the end of the five-year primary term. After the primary term ended on September 29, 2013, NWFCS entered into a new lease with Northern. NWFCS and Northern then filed suit in federal court based on diversity jurisdiction to determine whether the Continental lease had terminated. By consent, the case was assigned to a United States magistrate judge.

The magistrate issued two rulings on summary judgment. First, in 2016, the court ruled that although Continental had commenced drilling operations prior to the expiration of the primary term, the operations did not occur on the leased premises, and therefore the lease expired.[3] The following year, the magistrate ruled that Northern was not required to participate in the costs associated with Continental's well, which had been included in a spacing unit established after the date of the Northern lease.[4]

The district court entered final judgment on November 17, 2017.[5] Continental then appealed to the Ninth Circuit. Continental made three arguments on appeal: (1) the lease was successfully pooled prior to the expiration of the primary term; (2) a 2014 pooling order

3. N. Oil & Gas, Inc. v. Cont'l Res., Inc., No. CV 14-90-BLG-CSO, 2016 WL 3079692, at *7 (D. Mont. May 31, 2016).

4. N. Oil & Gas, Inc. v. Cont'l Res., Inc., No. CV 14–90–BLG–TJC, 2017 WL 4287201, at *5 (D. Mont. Sept. 27, 2017).

5. N. Oil & Gas, Inc. v. Cont'l Res., Inc., No. CV 14-90-BLG-TJC, 2017 U.S. Dist. LEXIS 190778 (D. Mont. Nov. 17, 2017) (order and final judgment).

should be applied retroactively; and (3) Northern should be judicially estopped from electing a nonconsent position.

In an unpublished opinion with little analysis, the Ninth Circuit rejected each of Continental's arguments. First, Continental argued that a temporary spacing unit approved by the Montana Board of Oil and Gas Conservation ("MBOGC") several years before the lease satisfied the pooling clause. The district court applied Montana contract law and rejected this interpretation, finding that the spacing unit was entered into for a different purpose than what was contemplated under the lease. Next, the Court found there was no legal basis to apply the 2014 spacing order retroactively. Finally, the Court upheld the magistrate's determination that Northern was not judicially estopped from electing a nonconsent position because Northern did not expressly or impliedly indicate consent to participate in the costs of the well.

While the case has minimal precedential effect, it does show how a federal court interprets Montana law for purposes of parties seeking participation in costs associated with a well where a spacing unit covers multiple leases. It also provides insight as to when a pooling clause will extend a lease when drilling operations occur on an adjacent parcel shortly before the end of the primary term of a lease.

B. *Murray v. BEJ Minerals, LLC*

In a diversity jurisdiction case decided in November 2018 and reported in the update last year,[6] the Ninth Circuit held that under Montana law, dinosaur fossils are "minerals" within the meaning of a mineral reservation contained in a deed.[7] Although the surface owner in this case owns a partial interest in the mineral estate, the ruling momentarily deprived the surface owner of the value of a nearly intact set of fossils of the two dinosaurs and a nearly fully intact Tyrannosaurus rex skeleton. The fossils potentially are worth millions of dollars, so the litigation and legal wrangling did not stop with the Ninth Circuit's ruling.

Following the ruling, Mary Ann and Lige Murray, the surface owners, petitioned for rehearing. On April 4, 2019, the Ninth Circuit

6. Stephen R. Brown, *Montana*, 5 TEX. A&M J. PROP. L. 57, 59 (2019).
7. Murray v. BEJ Minerals, 908 F.3d 437, 447–448 (9th Cir. 2018).

agreed to rehear the case en banc.[8] The en banc panel determined that there was no controlling Montana Supreme Court precedent to guide the federal court, and the issue of whether dinosaur fossils belong to the surface or the mineral estate "presents important public policy ramifications for Montana."[9] The court went on to note that the combination of frequently divided ownership in Montana and the state "possesses vast deposits of valuable vertebrate fossil specimens, which are substantial issues with broad application."[10] As of the date of this update, the case remains pending before the Montana Supreme Court.[11] Additionally, as discussed below, the 2019 Montana Legislature also stepped into this fray.

IV. Federal District Court of Montana

A. *WBI Energy Transmission, Inc. v. Subsurface Easements for the Storage of Natural Gas in the Judith River Subterranean Geological Formation*[12]

The Baker Storage Field has operated as a natural gas storage field in southeastern Montana since the 1940s. In 2011, the Montana Supreme Court issued an opinion clarifying that the surface owner, not the mineral interest owner, owns the pore space and the rights to subsurface storage of natural gas.[13] As a consequence, WBI Energy Transmission, Inc. ("WBI"), the field operator, was forced to negotiate leases with the various surface owners within the storage field.

WBI successfully negotiated leases with most surface owners. A few held out, so WBI filed a condemnation action in federal district court under the Natural Gas Act.[14] The defendants counterclaimed based on trespass and other legal theories. The federal magistrate

8. Murray v. BEJ Minerals, LLC, 920 F.3d 583 (9th Cir. 2019).
9. Murray v. BEJ Minerals, LLC, 924 F.3d 1070, 1071–072 (9th Cir. 2019) (en banc).
10. *Id.* at 1072.
11. Murray v. BEJ Minerals, LLC, OP 19-0304, 2019 WL 2383604 (Mont. June 4, 2019).
12. No. CV 18-88-BLG-SPW-TJC, 2019 WL 3470742, (D. Mont. July 08, 2019).
13. Burlington Res. Oil & Gas Co. v. Lang & Sons Inc., 259 P.3d 766 (Mont. 2011).
14. *See* WBI Energy Transmission, No. CV 18-88-BLG-SPW-TJC, 2019 WL 3470742 at *1 (D. Mont. July 08, 2019).

assigned to the case recommended that the counterclaims be dismissed on the grounds that they were precluded as a matter of law under Federal Rule of Civil Procedure 71.1, which is the procedural rule governing condemnation cases.[15]

B. *Fidelity Exploration & Production Co. v. Bernhardt*

In 2005, the United States Bureau of Land Management ("BLM") approved a plan for Fidelity Exploration & Production Co. ("Fidelity") to operate a 210-well coal bed natural gas project in Big Horn County, Montana. In addition to wells on federal leases, the project also included wells on state land and private land. In 2010, the BLM notified Fidelity that it was not correctly calculating production because it was improperly commingling production records from the various wells. The BLM also notified Fidelity that it was improperly deducting production used on the leases.

Fidelity disputed the BLM's allegations and appealed to the BLM State Director, then to the Interior Board of Land Appeals ("IBLA"), both of which upheld the BLM's determination. Fidelity then appealed the IBLA decision to federal district court, where it was assigned to a magistrate judge.[16]

The primary substantive issue addressed by the court was whether the BLM had approved Fidelity commingling gas prior to measurement and also using a gas off-lease for its operations. Fidelity contended both practices had been disclosed in the plan of operations submitted to the BLM and when the BLM approved the plan, it also approved these practices. Fidelity also argued that both practices are allowed by the rules that were in place prior to 2017.[17]

The court applied an arbitrary and capricious standard of review to BLM's interpretation of its own regulations. After reviewing the entire record, the magistrate found that while the rules do allow for gas from multiple wells to be commingled prior to measurement and a federal lessee may make off-lease beneficial use of gas, both practices require prior express federal authorization and each practice must be approved individually. Under the deferential administrative

15. Fed. R. Civ. P. 71.1.
16. Fid. Exploration & Prod. Co. v. Bernhardt, No. CV 16-167-BLG-SPW-TJC, 2019 WL 2029482 (D. Mont. Jan. 24, 2019).
17. *See* 43 C.F.R. § 3162.7-3.

standard of review, the magistrate found no express reference to approval of reporting based on commingled volumes. Merely approving a plan of operations without expressly approving the two practices was not sufficient.

Fidelity objected to the magistrate's findings and recommendations, but the objection was denied by the federal district court and the findings and recommendations were adopted in full.[18]

V. LEGISLATION

The Montana legislature meets for its regular session biannually in odd numbered years.[19] The 66th Montana Legislature convened on January 7, 2019 and adjourned on April 25.

A. *Oil and Gas Taxation*

Since 1999, Montana's tax code has included an oil and gas tax "holiday," which provides for a lower tax rate during the initial period after a well begins producing. The tax also is adjusted if the price of oil or natural gas drops below certain threshold prices.[20] Critics of the holiday argue it deprives counties of valuable revenue during what often is the most productive phase in the life of a well.[21] Supporters argue it incentivizes development. A bill to end the holiday was introduced but failed in committee.[22]

Ultimately, the legislature passed two bills relating to oil and gas taxation, but they only made minor corrections. House Bill 213 changed the benchmark for purposes of tax exemption from the west Texas intermediate crude oil price to the price reported and received

18. Fid. Exploration & Prod. Co. v. Bernhardt, No. CV 16-167-BLG-SPW, 2019 WL 1149975 (D. Mont. Mar. 13, 2019).

19. MONT. CONST. art. V, § 6.

20. *See* MONT. CODE ANN. § 15-36-304(5) (2019).

21. *See, e.g.*, Montana Budget & Policy Center, *Oil and Gas Tax Holiday: Montana Cannot Afford Giving Away Millions to Oil Companies*, (Jan. 2019), https://mbadmin.jaunt.cloud/wp-content/uploads/2019/01/Oil-and-Gas-Holiday-2019-FINAL.pdf [https://perma.cc/6JQH-Y4B2]; *See also*, *e.g.*, Montana Petroleum Ass'n., *Montana Oil and Gas Tax Rates*, https://montanapetroleum.org/educational-resources/montana-oil-gas-tax-rates/ [https://perma.cc/FV3X-32DP].

22. H.B. 691, 66th Sess. (Mont. 2019).

by the producer for Montana oil.[23] This change is favorable to producers because the Montana price often is lower. House Bill 656 changed how production taxes are used by the State after they are collected.[24]

B. *Defining the Term "Minerals" in Property Transaction Instruments*

Even though the Ninth Circuit agreed to rehear the *Murray* case, which found that Montana law presumes fossils are part of the mineral estate, the 2019 Legislature stepped in with a bill to codify the opposite interpretation. House Bill 229 states that when the term "minerals" is used in a property conveyance instrument, the term is not intended to include "fossils" unless the instrument clearly and expressly states otherwise.[25] The new law also specifies that fossils are not intended to be part of the general statutory provisions that govern mineral production. The new legislation has not affected the ongoing litigation in the *Murray* case.

23. H.B. 213, Reg. Sess. (Mont. 2019).
24. H.B. 656, Reg. Sess. (Mont. 2019).
25. H.B. 229, Reg. Sess. (Mont. 2019).

NEW MEXICO

Sharon T. Shaheen and John McIntyre[*]

I. STATE CASES

The New Mexico appellate courts issued no opinions relating to oil and gas in the past year.

II. STATE LEGISLATION

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A. *Produced Water Act, HB 546, codified at NMSA 1978, 70-13-1 to -5 (2019).*

Under the Produced Water Act ("Act") enacted in the 2019 regular legislative session, the New Mexico Legislature authorized the New Mexico Oil Conservation Division ("OCD") and the New Mexico Water Quality Control Commission ("WQCC") to regulate produced water resulting from oil and gas drilling or production.[1] The Act governs the transportation and sale of produced water,[2] recycled water (also referred to as recycled produced water),[3] and treated water (also referred to as treated produced water).[4] Unless otherwise provided by law or a legally binding document, responsibility and control of all produced water lies with both the working interest owners and the well operator. This responsibility and control remains until the water is transferred to another operator, transporter, pipeline, midstream company, plant, processing facility, refinery, or an entity engaged in recycling or treating services, at which point the transferee assumes responsibility and control.[5] The working interest owners and well operator have a possessory interest in the produced water, including but not limited to the right to transfer, sell, reuse, recycle, treat, or dispose of it, and that right passes to a transferee.[6] However, a transfer of responsibility and control under these provisions does not absolve one with responsibility and control with respect to claims made by third parties for damages.[7]

A state engineer permit is not required to transfer or dispose of produced water, treated water, or recycled water, and disposition of

1. Produced Water Act, N.M. STAT. ANN. § 70-13-3 (West 2019).
2. N.M. STAT. ANN. § 70-13-2(B) (West 2019) (Produced water is defined as "a fluid that is an incidental byproduct from drilling for or the production of oil and gas.").
3. § 70-13-2(C) (Recycled water and recycled produced water are both defined as "produced water that is reconditioned by a recycling facility permitted by the oil conservation division.").
4. § 70-13-2(D) (Treated water and treated produced water are both defined as "produced water that is reconditioned by mechanical or chemical processes into a reusable form.").
5. N.M. STAT. ANN. § 70-13-4(A)(1)-(2) (West 2019).
6. § 70-13-4(A)(1) to (3).
7. § 70-13-4(B).

such water does not establish a water right.[8] If the disposition of water falls under an activity regulated by the WQCC, however, then the party using the water must obtain a permit from the department of environment prior to use.[9] The following type of provisions in any agreement entered into on or after July 1, 2019 are considered against public policy and void: (1) allowing a private party to charge a tariff or fee for movement of produced water, treated water, and on surface lands owned by the state, if the agreement does not provide transportation services; (2) requiring an operator to purchase fresh water when produced water, treated water, or recycled water is available for use and the operator so chooses; or (3) relating to the purchase of water and precluding an operator from using produced water, treated water, or recycled water when available.[10]

Among other things, the Act also revised NMSA 1978, § 70-2-31, to provide authority to the OCD to impose civil penalties for violation of the Oil and Gas Act or any provision of a rule, order, permit, or authorization issued under the Act.[11] The Act provides a 30-day opportunity to cure after a notice of violation is entered, before a penalty is assessed.[12] A civil penalty may not exceed $2,500 per day of noncompliance for each violation unless the noncompliance poses a risk to public health or safety or of causing significant environmental harm, or unless the noncompliance continues beyond a time specified in a notice of violation or order, whereupon the penalty may not exceed $10,000 per day of noncompliance for each violation.[13] The Division will be publishing a proposed rule relating to penalties, and the hearing on the proposed rule is set for January 2, 2020. However, the new provisions of Section 70-2-31 become effective January 1, 2020.

B. *Relating to Oil and Gas; Imposing Fees; Creating a Fund; Making an Appropriation, SB 553, codified at NMSA 1978, § 70-2-39 (2019) (Fees; appropriation)*

8. § 70-13-4(C).
9. § 70-13-4(D).
10. N.M. STAT. ANN. § 70-13-5 (2019).
11. N.M. STAT. ANN. § 70-2-31 (2019) (effective Jan. 1, 2020).
12. § 70-2-31(B) to (C).
13. § 70-2-31(D).

In SB 553, New Mexico enacted legislation creating a fund to develop and modernize the OCD's and Oil Conservation Commission's ("OCC") electronic systems.[14] The fund will assist with modernization for case management and electronic filings. To pay for such modernizations, New Mexico now imposes the following non-refundable fees:

(1) $500 fee for applications for permits to drill on non-federal and non-Indian land;[15] applications for a fluid injection well permit;[16] and applications for an administrative hearing, re-hearing, or *de novo* hearing.[17]

(2) $150 fee for applications for administrative approval of a non-standard location, for downhole commingling, for surface commingling, for off-lease measurement, for release notification and corrective action, for a change of operator, for a modification to a surface waste management facility, for a request to create a new pool, for a proposed alternative method permit, for a closure plan application, or for authorization to move produced water.[18]

(3) $150 fee for applications for a continuance of an administrative hearing, re-hearing, or *de-novo* hearing.[19]

(4) $10,000 fee for applications for a permit to construct a surface waste management facility, a landfill, or a landfarm.[20]

III. FEDERAL CASE

A. *Diné Citizens Against Ruining Our Environment v. Bernhardt, 923 F.3d 831 (10th Cir. 2019)*

The primary issue in *Diné Citizens Against Ruining Our Environment v. Bernhardt*[21] is whether the Bureau of Land Management ("BLM") violated the National Historic Preservation Act

14. N.M. STAT. ANN. § 70-2-39(C) (2019).
15. § 70-2-39(A)(1).
16. § 70-2-39(A)(3).
17. § 70-2-39(A)(5).
18. § 70-2-39(A)(2).
19. § 70-2-39(A)(6).
20. § 70-2-39(A)(4).
21. 923 F.3d 831, 835 (10th Cir. 2019).

("NHPA") and the National Environmental Policy Act ("NEPA") in granting Applications for Permits to Drill ("APD"). The 10th Circuit affirmed the district court's dismissal of Appellants' NHPA claims but reversed and remanded the district court's dismissal of their NEPA claims. The Court held that the BLM failed to consider the cumulative impacts of water use when it approved APDs that would allow the drilling of thousands of wells located in the Mancos Shale of the San Juan Basin. The opinion focuses on three sections of legal analysis: (1) standing; (2) NHPA violations; and (3) NEPA violations.

The 10th Circuit first considered whether Appellants' members had "standing to sue in their own right" asking if Appellants' members had "(1) . . . suffered an injury in fact that is (a) concrete and particularized and (b) actual and imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) it is likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision."[22] The Court concluded that Appellants could establish an injury in fact, linking BLM's actions to increased environmental risks, by showing that issuance of the APDs could impact the visual landscape, view of the sky at night, peacefulness, and public health and safety.[23] The Court further concluded that the injury in fact was concrete and particularized[24] because Appellants' members regularly visited the areas that covered the APDs for recreational amusement, saw increased truck traffic and development activity, and witnessed air pollution created by trucks and machinery.[25] The Court determined that Appellants' allegations of BLM's failure to comply with NEPA evidenced a link between BLM's uninformed decision-making and a risk of harm.[26] Finally, the Court concluded Appellants established a likelihood that their injury would be redressed by a favorable decision because requiring BLM to comply with NEPA would avert the possibility that BLM may have missed significant environmental consequences.[27] Thus, the Court concluded that Appellants had standing to bring their claims.

22. *Id.* at 839.
23. *Id.* at 840–41.
24. *Id.* at 841.
25. *Id.* at 841–42.
26. *Id.* at 842–43.
27. *Id.* at 844.

Before moving to the merits, the Court bemoaned the "dramatic insufficiency of the record," noticing that Appellants challenged more than 300 individual agency actions, yet provided a complete record for only a few.[28] Consequently, the Court limited its review of the merits to only six of the challenged actions.[29]

The Court first considered whether BLM had violated the NHPA. Satisfying the NHPA requires a four-step process: (1) defining an "area of potential effects" ("APE"); (2) locating historic sites within the area;[30] (3) determining whether the proposed activity being permitted will "adversely affect" the historic sites; and (4) if activity will have an adverse effect, whether alternatives or modifications will "avoid, minimize, or mitigate" such effects.[31] The Court determined that BLM satisfied the requirements of the NHPA because, *inter alia*, a separate indirect-effects APE was not required,[32] BLM identified cultural properties outside of the direct-effects APE, that BLM considered indirect effects on those properties,[33] that no historical sites existed within the geographic area,[34] and that BLM was not required to consult with the state historic preservation office.[35] Therefore, the Court concluded that Appellants' NHPA failed.[36]

The Court then considered Appellants' NEPA claims. Under NEPA, an agency must evaluate environmental impacts "significantly affecting the quality of the human environment."[37] Applied to APDs, the BLM must examine the environmental impacts of proposed drilling activities by either issuing an environmental assessment ("EA") or an environmental impact statement ("EIS") associated with approving an APD.[38] An EA must analyze the direct, indirect, and cumulative effects of a proposed project.[39] The preparer of an EA can reach one of three conclusions: (1) the action will result in a significant

28. *Id.*
29. *Id.* at 845.
30. *See id.* at 846. If no historic properties exist within the geographic area, then the analysis does not move to steps 3 and 4.
31. *Id.*
32. *Id.* at 847–48.
33. *Id.* at 848.
34. *Id.* at 849.
35. *Id.* at 850.
36. *Id.*
37. *Id.* at 850–51 (citing 42 U.S.C. § 4332(2)(C)).
38. *Id.* at 837, 851.
39. *Id.* at 837, 851 (citing 40 C.F.R. §§ 1508.7 and 1508.8).

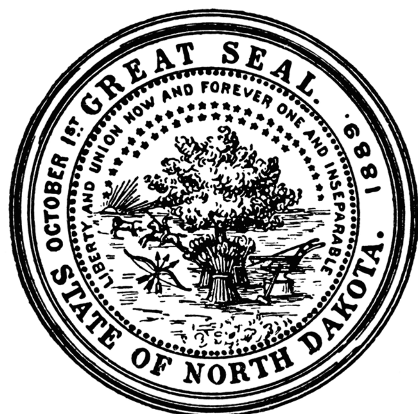
environmental impact; (2) the action will not result in a significant environmental impact; or (3) the action will not go forward.[40] If a significant environmental impact will result, then an EIS is required; if not, then there is a "finding of no significant impact," or a "FONSI."[41] When reviewing a complaint for NEPA violations, courts look at whether "the agency has adequately considered and disclosed the environmental impacts of its actions."[42] In doing so, a court uses "a 'rule of reason standard' to determine whether claimed NEPA violations 'are merely flyspecks, or are significant enough to defeat the goals of informed decision making and informed public comment.'"[43]

In approving the six APDs considered by the Court, BLM tiered the pertinent EAs to an EIS prepared in 2003.[44] Subsequent to the 2003 EIS, however, when the development of the Mancos Shale began in earnest, BLM issued a "reasonably foreseeable development scenario" ("RFDS"), which estimated that full development would result in 3,960 new wells.[45] Because the EAs relating to the six APDs did not consider the cumulative impacts of drilling 3,960 new wells, the Court concluded that Appellants' claims under NEPA could go forward.[46] Among other things, Appellants challenged BLM's failure to analyze the cumulative impacts of the 3,960 wells on air and water.[47] The Court rejected Appellants' claims relating to air pollution because Appellants failed to provide a sufficient record. [48] However, the Court found that BLM failed to consider the cumulative effect of 3,960 wells on water use concerning five EAs and therefore reversed the district court's dismissal of Appellants' EPA claims concerning those five EAs.[49] By failing to consider the cumulative impacts that drilling would have on water resources, the BLM acted arbitrarily and

40. *Id.* at 837 (citing 40 C.F.R. § 46.325).
41. *Id.* at 851 (citing 40 C.F.R. § 1508.13 and 42 U.S.C. § 4332(C)).
42. *Id.* at 851 (quoting Coal. of Concerned Citizens to Make Art Smart v. Fed. Transit Admin., 843 F.3d 886, 902 (10th Cir. 2016)).
43. *Id.* at 852 (quoting Utahns for Better Transp. v. U.S. Dep't of Transp., 305 F.3d 1152, 1163 (10th Cir. 2002)).
44. *Id.* at 851–52. .
45. *Id.* at 837.
46. *See id.* at 852.
47. *Id.*
48. *Id.*
49. *Id.*

capriciously when it issued the APDs associated with the five EAs.[50] Therefore, the Court remanded the case to the district court with instructions to vacate the five APDs and to remand the case back to BLM to conduct a proper NEPA analysis.[51]

50. *Id.* at 857.
51. *Id.* at 859.



NORTH DAKOTA

DEALING WITH DUBIOUS CONTRACTS FOR CONVEYING LAND STATUTE OF LIMITATIONS OR REFORMATION FOR MUTUAL MISTAKE?

William P. Pearce

The topic of this Article arose from a recent opinion by the North Dakota Supreme Court: *Western Energy Corporation v. Stauffer*.[1] The case dealt with how the law handles changes in ownership of property, specifically land including underlying mineral interests, that come into dispute after substantial periods of time have passed, resulting in a need for the parties involved in the dispute to turn to the courts for a solution. The passing of a substantial amount of time often becomes the issue in resolving the dispute in these types of situations.

The opening paragraph in the Court's opinion in *Western Energy* states that "Western Energy appealed from a district court judgment finding its quiet title action pertaining to claimed mineral

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1. 921 N.W.2d 431 (N.D. 2019).

interests to be barred by applicable statutes of limitation and laches." Statutes of limitation are fairly straightforward and are discussed below as they are the determinative factor in the case. However, the specific goal here is to examine several of the approaches that can be taken in this kind of situation and how the issue is ultimately resolved. Raising the claim of "laches" is a rather vague concept, but it appears in some of these cases and has an interesting background, as discussed in the last part of this Article. The background of the case in question will be laid out first followed by the discussion of several traditional methodologies for resolving cases of this kind, generally, in the context of other court cases.

I. WESTERN ENERGY CORPORATION V. STAUFFER

On May 25, 1959, members of the Eckman family, owners of a tract of land, agreed to convey a portion of their real property to members of the Stauffer family using a typical contract for deed to accomplish the transfer. The contract for deed contained a reservation of the underground oil, gas, and other minerals in the property in question, which is not an unusual practice in the western part of North Dakota where there are large underground deposits of these minerals. The contract for deed was on a five-year payment plan, after which the Eckmans were to convey the tract to the Stauffers by a warranty deed, the usual document used for completing the transfer of land. The actual conveyance of the property by the warranty deed was made very early, in June 1959, rather than on a five-year plan, but the timing is not particularly relevant to the case. However, the source of the ensuing problem was that the June 1959 warranty deed did not contain any reservations of minerals, although it expressly stated that the deed was given "in fulfillment of the contract for deed issued on the 25th of May 1959."[2]

At this point, a potential problem came into existence because there was an uncertainty regarding the status of the mineral interest. The apparent agreement between the Eckmans and the Stauffers was that 50% of the minerals were to be reserved, meaning they would not be included in the grant of the land made by the warranty deed. The statement that the warranty deed from the Eckmans to the Stauffers

2. *Id.* at 433.

was made in fulfillment of the contract for deed appears to support the passing of the mineral interests as well as the surface of the land, since there was no actual reservation of minerals in the deed itself. Under North Dakota statutory law, a conveyance of mineral rights in real property grants all minerals except those specifically excluded by name:

> All conveyances of mineral rights or royalties in real property in this state, excluding leases, shall be construed to grant or convey to the grantee thereof all minerals of any nature whatsoever except those minerals specifically excluded by name in the deed, grant, or conveyance, and their compounds and byproducts.[3]

Since the warranty deed did not contain any mineral reservation, or apparently any reference to mineral interests, it appears to have conveyed all of the mineral interests in the tract in question to the Stauffers. A conveyance of land that does not explicitly include a reservation of minerals automatically includes the minerals that are a part of the land unless there has been an intentional severance of minerals from the land. Since the Eckmans did not include any such reservation or severance of minerals in their warranty deed to the Stauffers, the land with the minerals passed to the Stauffers. This result has been clearly stated by the North Dakota Supreme Court, following the established rule that a grant without a reservation shall be interpreted in favor of the grantee, and "[a] conveyance of land, without any exception or reservation of minerals constitutes a conveyance of 100 percent of the minerals as well as the surface.[4]

A quiet title action was filed by Western Energy Corporation in 2016 against a number of successors of the Stauffers. The Court's opinion does not does not specify the detailed basis for the quiet title action, but apparently numerous conveyances, oil and gas leases, and similar transactions were carried out by both the Eckmans and the Stauffers and their successors between 1959 and 2016. Beginning in 1978, the Eckmans apparently began entering into agreements

3. N.D. CENT. CODE § 47-10-24 (2014).
4. Acoma Oil Corp. v Wilson, 471 N.W.2d 476, 482 (N.D. 1991) (citing Sibert v. Kubas, 357 N.W.2d 495, 496 (N.D. 1984)).

conveying mineral interests, which they may have believed they had retained and were entitled to when the warranty deed was delivered to the Stauffers. Western Energy Corporation entered the picture in 1989 and 1990 by acquiring mineral interests, including mineral interests that were all or portions of the interests the Eckmans had failed to reserve in the June 1969 warranty deed. The Court does not specify the various mineral interests in detail. However, the disputed mineral interests must be the basis for the quiet title action, since the only mineral interests that Western Energy would be seeking to obtain by quiet title action against the Stauffer successors would be the mineral interests that passed to the Stauffers via the original warranty deed that contained no mineral reservation.

The Supreme Court opinion does not specify from whom these interests were derived, but presumably it would have been from some or all of the persons involved in the case in an effort to clarify the actual ownership of the mineral interests in the land in question. Although the action was nominally brought as a quiet title action,[5] the Supreme Court points out that the relief requested was not for quiet title. Instead, it was actually for reformation of the warranty deed, presumably because the deed did not contain a reservation of minerals and was different from the original agreement.[6] To successfully establish a basis for a reformation of the deed would require that there had been a sufficient mistake or mistakes to subsequently alter the terms of the deed. The district court concluded that the discrepancy between the contract for deed and the warranty deed itself was not sufficient to establish mutual mistake that could support a reformation.

After several years, the situation had become more complicated, so a simple reformation by inserting a missing mineral reservation into the deed had become difficult, in view of all of the various transactions. The Supreme Court, on appeal from the district court, pointed out that numerous conveyances, oil and gas leases, and similar transactions were completed by both the Eckmans and Stauffers, as well as their successors in interest, during the period of time between the execution of the 1959 deed and the filing of the quiet title action in 2016. As stated above, the Eckmans conveyed mineral interests to others, perhaps even interests that they may have deemed

5. *See* Actions to Quiet Title and Determine Claims to Real Estate, N.D. CENT. CODE. § 32-17-1 *et seq.* (2010).
6. *W. Energy Corp.*, 921 N.W.2d at 434.

they owned, based on the agreement for a mineral reservation in the contract for deed to the Stauffers.

In reality, the warranty deed should accomplish exactly what it says it intends to do. If there is no reservation of minerals stated in the deed, would that not mean that it was certain that no mineral reservation was intended? Despite the action being framed as a quiet title action, as noted above, the North Dakota Supreme Court recognized that the relief requested by Western Energy was actually to reform the warranty deed to comply with the original contract, which contained the reservation of minerals.[7] So, the issue that forms the core of the case is: Does the law allow for changes, or corrections, to be made in 2016 in a warranty deed that was created and delivered in 1959? Not surprisingly, the answer in the *Western Energy* case was "no". The point of this Article is to look at a few of the more common legal methods that may be used to attempt to seek a "yes" answer in a case of this kind.

II. REFORMATION OF A DEED OR CONTRACT FOR MUTUAL MISTAKE

The *Western Energy* quiet title action set the stage for establishing exactly who owns certain underlying mineral interests, presumably including those originally owned by the Eckmans, when there was no reservation in the warranty deed. This is the basic issue brought forth in a quiet title action, which is "a proceeding to establish the plaintiff's title to land by bringing into court an adverse claimant and there compelling him either to establish his claim or be forever after estopped from asserting it."[8] Although the proceeding was brought as a quiet title action, the Court shows that the relief sought was actually to proceed with a reformation of the warranty deed. The theory behind reformation of a document is that in the course of creating it the parties inadvertently made a "mutual mistake." If it can be proven that there was a mutual mistake, then there is a basis for a court to approve the document to be revised to correct the mistake. In other words, the court can order the reformation or correction of the original document to adapt it to the document that presumably was

7. *See also* Larry A. DiMatteo, *Equity's Modification of Contract: An Analysis of the Twentieth Century's Equitable Reformation of Contract Law*, 33 NEW ENG. L. REV. 265 (1998) (reformation of contracts).
8. *Quiet*, BLACK'S LAW DICTIONARY 1416 (4th ed. 1968).

intended to be created by the individuals who wrote it. Reformation of a written document is an appropriate result when the surrounding circumstances justify it. A court will grant relief by way of reformation of a written instrument resulting from a mutual mistake, but all of the circumstances must be taken into consideration:

> Each case involving the reformation of a contract on grounds of fraud or mutual mistake must be determined upon its own particular facts and circumstances. In considering whether or not a mutual mistake exists, the court can properly look into the surrounding circumstances and take into consideration all facts which disclose the intention of the parties.[9]

If the facts and circumstances are sufficiently clear to justify the granting of a reformation of the document or documents in question, of course, the court would look favorably upon granting it, assuming that the case is not more appropriately handled by a statute of limitations, as in the *Western Energy* case.[10]

The North Dakota statutory basis for approving reformation of a document is set out as follows:

> When, through fraud or mutual mistake of the parties, or a mistake of one party which the other at the time knew or suspected, a written contract does not truly express the intention of the parties, it may be revised on the application of a party aggrieved so as to express that intention so far as it can be done without prejudice to rights acquired by third persons in good faith and for value.[11]

The lower court was not convinced that the discrepancy between the warranty deed and the contract for deed—the reservation of the mineral interests—was sufficient to establish mutual mistake. Not surprisingly, the Supreme Court's conclusion was the same simply

9. Ell v. Ell, 295 N.W.2d 143, 150 (N.D. 1980).
10. *See* Zabolotny v. Fedorenko, 315 N.W.2d 668 (N.D. 1982) (holding that reformation was the most logical and appropriate resolution).
11. N.D. CENT. CODE § 32-04-17 (2010).

because it would seem to have been peculiar and unlikely that the parties would have not have noticed in examining the recorded documents that there was a mineral reservation in the original contract for deed but nothing of that kind contained in the warranty deed. In fact, it seems relatively straightforward that the Stauffers ought to have acquired the mineral interest since they received a warranty deed that did not contain any mineral reservation and accordingly would necessarily have transferred all of the mineral interests.

In addition to mutual mistake, it is possible in some cases for fraud of some kind to have occurred, but there appears to be no evidence of fraud having been a factor in the *Western Energy* case. However, there could always be something that occurs other than the sheer overlooking of some step in the process or transferring an interest in land, and the person bringing the claim has the burden to explain the problem. As the North Dakota Supreme Court has pointed out:

> A party seeking reformation has the burden to prove by clear and convincing evidence that a written agreement does not fully or truly state the agreement the parties intended to make.[12] The burden of proof rests on the party who seeks a reformation to prove that the written instrument does not fully or truly state the agreement that the parties intended to make.[13]

Any case involving a claim for reformation of a document or documents must take into account all of the relevant facts in any given situation, meaning there is no standard scenario that will support a reformation. Included in the concept of "relevant facts" in modern times would be the possibility of introducing parol evidence, meaning oral evidence rather than written evidence, in support of a claim for reformation, but the standard for this is generally high:

> The Supreme Court's sanctioning of the use of circumstantial parol evidence to prove mutual mistake

12. Dixon v. Dixon, 898 N.W.2d 706, 711 (N.D. 2017) (quoting Freidig v. Weed, 868 N.W.2d 546, 549 (N.D. 2015)).
13. Ell, 295 N.W.2d at 150 (citing Oliver-Mercer Electric Cooperative, Inc. v. Fisher, 146 N.W.2d 346, 356 (N.D. 1966)).

> is noteworthy here. Initially the Court acknowledged a high standard for use of parol evidence to prove mutual mistake: such evidence must be clear, satisfactory, specific, and convincing, and a court of equity will not grant reformation upon a mere preponderance of evidence, but only upon certainty of error.[14]

Whether a mistake exists in a document that would have been sufficient to justify a claim of reformation involves looking at "each case involving the reformation of a contract on grounds of fraud or mutual mistake must be determined upon its own particular facts and circumstances."[15]

It should also be kept in mind when faced with a claim for reformation that it is not always a simple matter to determine whether there is a clear mistake in a contract:

> The inconsistency of the decisions as to the effect of mistake in contracting is due to the fact that Anglo-American law is torn between the desire for stability of commercial transactions and the feeling that is it unfair to hold a party to a contract that he made without complete information about all the relevant circumstances. The latter consideration rests on a sense of fair play which looks with disfavor on permitting anyone to reap an advantage from another party's mistakes.[16]

Therefore, the essential basis for a successful action for reformation of a document is that it must be shown by substantial evidence that an actual mistake occurred in the creation of the document that is significant enough that the mutual intention of the parties to the document is not what was included in the document. As the Court stated in the *Western Energy* case:

14. Alexandra P. Everhart Sickler, *Recent Developments in North Dakota Contract Law*, 92 N.D. L. REV. 19, 37 (2016).
15. Mau v. Schwan, 460 N.W.2d 131, 134 (N.D. 1990).
16. Ralph A. Newman, *Relief for Mistake in Contracting*, 54 CORNELL L. REV. 232, 236–37 (1969).

> Further, the district court concluded the discrepancy between the contract for deed and the warranty deed is not enough to establish mutual mistake. Because it found that Western had not met the burden of proof to establish mutual mistake at the time of conveyance, the district court entered judgment quieting title of the minerals to the Stauffers.[17]

To establish the existence of a mistake that would be sufficiently important to justify a reformation of a document, the party claiming the existence of a genuine mistake must prove there was a firm basis for alleging the claim:

> Here, the district court found numerous transactions involving the property and mineral rights occurred in the decades since the warranty deed was executed and recorded. The district court found these transactions, including a completed title opinion, gave all parties reason to review the title record. An examination of the title record would have disclosed the difference between the contract for deed and the warranty deed. The district court thus concluded that any alleged mutual mistake was, or should have been, discovered with reasonable diligence in 1959 when the documents were executed, or in the intervening fifty-nine years since the execution of the warranty deed.…A simple examination of the title records would have revealed competing leases on the property as well as the discrepancy between the 1959 contract for deed and the warranty deed.[18]

In *Anderson v. Selby*,[19] the North Dakota Supreme Court also held that there was no basis for a reformation action in a somewhat similar situation to the one in *Western Energy*. The Andersons had conveyed a parcel of land, reserving oil, gas, and other minerals, and

17. W. Energy Corp. v. Stauffer, 921 N.W.2d 431 (N.D. 2019).
18. *Id.* at 435.
19. 700 N.W.2d 696 (N.D. 2005).

they also intended to reserve a flowage easement. This easement was a right to raise the elevation of the water table in connection with a dam project in which the Andersons had offered the easement to the United States Army Corp of Engineers in charge of the project. However, the warranty deed from the Andersons to Selby did not contain a flowage easement. The Andersons, not wishing to lose the large payment they would have received from the Corps for the easement, sued Selby, seeking a reformation of the deed to include a reservation of the easement, which had not been included in the deed. Selby denied that there had been a mutual mistake regarding a reservation of the easement. The district court granted summary judgment in favor of Selby on the Andersons' claim, thereby declining to grant a reformation. On appeal by the Andersons, the North Dakota Supreme Court determined that there was sufficient evidence to consider the matter:

> Although the Andersons have the ultimate burden of proof to show by clear and convincing evidence that they are entitled to reformation because of a mistake which Selby at the time knew or suspected, we believe there is evidence in this record which supports an inference that such a mistake was made. We therefore conclude summary judgment was not appropriate on the Andersons' claim for reformation.[20]

In other words, it was a matter of the two different courts viewing the evidence differently as to whether there could have been a mutual mistake that could have supported a reformation of the deed.

III. WEHNER v. SCHROEDER: SOME SIMILARITIES TO WESTERN ENERGY BUT A DIFFERENT RESULT

Another case, *Wehner v. Schroeder*,[21] which was similar but different to the *Western Energy* case, came before the North Dakota Supreme Court in 1984. The plaintiff sought reformation of a warranty

20. *Id.* at 701.
21. 354 N.W.2d 674 (N.D. 1984). The earlier Wehner v. Schroeder case, 335 N.W.2d 563 (N.D. 1983), ended in a remand which then led to the subsequent 1984 case.

deed on the same grounds as in W*estern Energy*—that a mineral reservation agreed upon in a contract for deed had been omitted from the subsequently recorded warranty deed. However, there was a peculiar quirk because the 1950 contract for deed stated that the "second parties," the Schroeders, who were the grantees in the deed, "retain 50% of all oil, gas and minerals on said land." The peculiarity is that the grantees were not the ones who were to retain the mineral interest since that was owned by the grantors [the Wehners], who would necessarily be the only persons who could be able to retain any of the minerals since they owned them. Both the contract for deed and the warranty deed had been recorded in 1950. Since that was done, the tract became the property of the Schroeders, but the 50% mineral interest was left somewhere in limbo because a contract for deed is not a grant and does not actually convey an interest in land but simply is a contractual promise to convey it via a warranty deed.

In 1981, the Wehners brought an action to reform their warranty deed, stating that "second parties" was an error, and they intended to have "first parties," meaning themselves as the grantors in the deed. They also asserted that the mineral reservation in the contract for deed was omitted from the warranty deed due to an "innocent mutual mistake" made by both of them and the Schroeders. Other parties had acquired some interests, but it is not necessary to look into that aspect. The district court found that a mutual mistake has been made between the Wehners and the Schroeders regarding the omission of the mineral reservation in the warranty deed, and this provided the basis for approving a reformation of the document. The question of reformation of a contract or other kind of document is often referred to as a matter for the "equity" courts, as mentioned later in this article: "A court of equity will grant relief by way of reformation of a written instrument, resulting from mutual mistake where justice and good conscience so dictate."[22] In affirming the grant of reformation from the district court in Wehner v. Schroeder, the North Dakota Supreme Court summarized as follows:

> We believe that in order to bar reformation under these particular circumstances, the fault of the party

22. Zabolotny v. Fedorenko, 315 N.W.2d 668, 671 (N.D. 1982) (citing Cokins v. Frandsen, 141 N.W.2d. 796, 798 (N.D. 1966)).

> requesting relief must amount "to a failure to act in good faith and in accordance with reasonable standards of fair dealing." Restatement (Second) of Contracts § 157 (1981)….The trial court found no evidence that the Wehners failed to act in good faith or in accordance with reasonable standards of fair dealing. We have reviewed the record in this case and cannot say that the trial court erred in this regard.
>
> . . .
>
> The trial court found that a mutual mistake had occurred, and, as we stated earlier, that finding is not clearly erroneous. The doctrine of merger therefore does not bar reformation in this case.[23]

In the law of real property, the doctrine of merger stands for the proposition that a contract for the conveyance of real property merges into the related deed of conveyance:

> One of the most firmly established common law doctrines governing real property involves the merger of rights stemming from a land sale contract into the deed that consummates the transaction…. In essence, because the deed is presumed to supersede all preceding negotiations and agreements, all rights and remedies of the parties in relation to the transaction must be determined by the deed. Most practitioners prepare real estate contracts with the belief that the doctrine will apply and merge the provisions of the contract in the deed.[24]

Therefore, any guarantees made in the contract that are not reflected in the deed are extinguished when the deed is conveyed to the buyer of the property. In other words, the Court seems to be saying that the approved reformation in this case essentially blends the contract and the warranty into a single entity, which was appropriate in view of the approval of the claim for reformation. A number of other cases seeking reformation of documents have been brought over the

23. Wehner, 354 N.W.2d at 679.

24. Barry M. Goldman, *Common Law Doctrine of Merger: The Exceptions are the Rule*, 13 U. BALT. L. REV. 19 (1983).

years before the North Dakota Supreme Court, and there is one opinion, granted in 1966, which seems particularly lucid in dealing with this issue. In *Cokins v. Frandsen*, the issue arose when a buyer and a seller entered into an agreement for the purchase and sale of a real estate tract on which a restaurant was located. In the course of an engineering survey it was discovered that the description of the tract in the agreement was erroneous. The buyers brought an action for reformation to correct the instrument. At the outset, the Court stated clearly the basic situation required in order for reformation to take place:

> In order that the court may order reformation of the description of real estate in an instrument, it must appear that there has been a mutual mistake. In other words, it must be shown that, at the time of the execution of the agreement to sell, both parties intended to say something different from what was said in the instrument. In such event, equity has the power to reform the instrument to correct the mutual mistake of the parties.[25]

The Court in *Cokins*, as opposed to some of the other cases, determined that a mutual mistake had been by both the buyer and the seller in drafting the purchase agreement, due to an error in the description of the tract of land in question. Accordingly, this was an appropriate case for the equitable relief of reformation:

> There being a mutual mistake in the description, such mutual mistake justifies the reformation of the description in the purchase agreement, and the judgment of the trial court granting reformation of the description in the purchase agreement and the deed is affirmed.[26]

IV. STATUTE OF LIMITATION: CLOSING THE GATE

25. Cokins v. Frandsen, 141 N.W.2d 796, 799 (N.D. 1966) (citing Williams v. Hebbard, 92 P.2d 657 (Cal. 1939)).
26. *Id.* at 800 (citing Wilson v. Pulsfut, 49 N.W.2d 102 (N.D. 1951)).

As discussed above, the attempt to alter the contract and warranty deed problem in the *Western Energy* quiet title action by reformation based on mutual mistake failed due to a lack of any basis for asserting a "mutual mistake." The actual solution the district court used, and the North Dakota Supreme Court approved, was the Statute of Limitations. The extensive lapse of time during which there was no complaint from Western Energy Corporation simply shut the matter down insofar as seeking a reformation. As pointed out by the North Dakota Supreme Court at the opening of its opinion, Western Energy Corporation appealed from a district court judgment that found its quiet title action to have been barred by applicable statutes of limitation and laches, and the mineral interests at issue having been awarded to the Stauffers. Accordingly, the district court's judgment was affirmed.

The term "laches" used in the Court's statement is discussed below. At this point, it is the statute of limitations that is the determining factor. The North Dakota statute of limitations pertaining to conveyances such as occurred in this case is N.D. Cent. Code Ann. § 28-01-15, labeled in the code volume as "Actions having ten-year limitations**.**" There are several subsections to this statute, and the Court cites § 28-01-15(2), as the district court had also done, which provides that any legal action based on contracts or any other instruments affecting title to real property must be commenced within ten years following the time the claim for relief accrues. Accordingly, since a substantial number of years more than ten had passed from the delivery of the warranty deed in 1959 to the bringing of the quiet title action by Western Energy in 2016—57 years—there was clearly no question that the quiet title action must disappear, and the Stauffers finally became established as the owners of the mineral interest in question after what clearly appeared to be an extended period of uncertainty and confusion.

The history of Statutes of Limitation is an interesting one. Such principles developed first under English law and, as with many other legal principles, gradually expanded to become parts of American law:

> The principle [statutes of limitation] was first adopted in English law in connection with actions for the recovery of real property. . ..The various States [American] possess their own statutes of limitation

> which are modeled in the main upon the English but differ widely in their minor details.[27]

In fact, it has been pointed out that the concept of statutes of limitation may actually be traced as far back as to ancient Greece, and the first one to appear pertaining to real property actions under English law was a 1487 statute enacted during the reign of King Henry VII. The first such English statute was adopted by American colonies before the 1776 Revolution and ultimately became the foundation of nearly all subsequent American statutes of limitation.[28]

The statutes of limitation constitute a very useful factor in the American legal system and by no means are they intended to provide an easy way for courts to limit the number of cases that may be piling up on the dockets. They have a definite purpose, which is clearly reflected in the analysis and opinion of the Supreme Court in this case, as well as in the same result originally reached in the district court. The following summaries of the function and purpose of the statutes of limitation demonstrate the underpinning of the clearly appropriate result in this case:

> Statutes of limitation are vital to the welfare of society, and are favored in the law. They are found and approved in all systems of enlightened jurisprudence. They promote repose by giving security and stability to human affairs; important public policy lies at their foundation. Thy stimulate … activity and punish negligence. While time is constantly destroying evidence of rights, they supply its place by a presumption which renders proof unnecessary. Mere delay, extending to the limit prescribed, is itself a conclusive bar.[29]

A good characterization for statutes of limitation is they provide a kind of repose, preventing dubious claims from possibly lingering forever in the judicial system:

27. *Statute of limitations*, ENCYCLOPEDIA BRITANNICA (14th ed. 1953).

28. Tyler T. Ochoa and Andrew Wistrich, *The Puzzling Purposes of Statutes of Limitation*, 28 PAC. L.J. 453, 454 (1997).

29. *Id.* at 456 (quoting Wood v. Carpenter, 101 U.S. 135, 139 (1879)).

> The statute of limitations is a statute of repose, enacted as a matter of public policy to fix a limit within which an action must be brought, or the obligation is presumed to have been paid, and is intended to run against those who are neglectful of their rights, and who fail to use reasonable and proper diligence in the enforcement thereof….These statutes are declared to be 'among the most beneficial in our books' 'They rest upon sound policy, and tend to the peace and welfare of society.'….The underlying purpose of statutes of limitation is to prevent the unexpected enforcement of stale claims concerning which persons interested have been thrown off their guard by want of prosecution.[30]

V. LACHES: AN OLD-TIMER IN LEGAL HISTORY BUT STILL ALIVE

The North Dakota Supreme Court's opinion in the *Western Energy* case discussed above opens with a reference to the district court judgment "finding its quiet title action to be barred by applicable statutes of limitation and laches." The actual holding was the action was effectively barred by the statute of limitation. The word "laches" is an old term that evolved from Latin ("laxus") and Old French ("laschesse"), meaning laxness, slackness, negligence, and the like, usually in the course of legal matters. Laches is embedded in the legal concept of "equity," which has been described in a variety of ways. A typical legal description of equity is:

> In its broadest and most general signification, this term [equity] denotes the spirit and the habit of fairness, justness, and right dealing—the rule of doing to all others as we desire them to do to us; or; as it is expressed by Justinian, "to live honestly, to harm nobody, to render to every man his due."[31]

30. *Id.* (citing Pashley v. Pacific Elec. Co., 153 P.2d 325, 326 (Cal. 1944)).
31. *Equity*, BLACK'S LAW DICTIONARY (Rev. 4th ed. 1968). (Justinian was, of course the Byzantine emperor from A.D. 527 to 565, who compiled the famous book of laws entitled the Justinian Code.).

Having defined "equity," we can see how the concept of "laches" is embedded into the function of equity as an integral part of the legal process carried on by the courts:

> Generally speaking, laches is a defense in equity that stands for the proposition that a court will not find for the plaintiff if the plaintiff delayed in bringing the case, and that delay harmed the defendant…. Accordingly, laches has traditionally had two, or at most three, components—delay, a position change for the worse, and a loss of evidence."[32]

Unreasonable delay in bringing an action before a court is not the sole feature of laches but it establishes the fundamental basis of this concept insofar as it affects an opposing party:

> Laches is a delay or lapse of time in commencing an action that works a disadvantage or prejudice to the adverse party because of a change in conditions during the delay.[33]
>
> Laches does not arise from a delay or lapse of time alone, and in addition to the time element, the party against whom laches is sought to be invoked must be actually or presumptively aware of his rights and must fail to assert them against a party who in good faith permitted his position to become so changed that he could not be restored to his former state.[34]

In the historical legal context, laches came to be appropriated by the English chancery courts, where decisions could be made by the judges that were more flexible than what would be required under the strict legal rules that had been established under the common law.[35]

32. Kathryn E. Fort, *The New Laches: Creating Title Where None Existed*, 16 GEO. MASON L. REV. 357, 365 (2009).

33. Williams Cty. Soc. Servs. Bd. v. Falcon, 367 N.W.2d 170, 174 (N.D. 1985).

34. Burlington N., Inc. v. Hall, 322 N.W.2d 233, 242 (N.D. 1982).

35. KERMIT L. HALL, THE MAGIC MIRROR: LAW IN AMERICAN HISTORY 22 (1989) ("Equity, however, had emerged in the colonies as a matter of practice, if not of form. Seventeenth century colonial lay judges exercised a kind of equity through

The basic outcome of the application of laches is that a legal right or claim may not be enforced or allowed if an unreasonably long delay in asserting the right or claim has prejudiced the other party. Historically, there was a kind of connection between laches and statutes of limitation, possibly on the theory that the mere passage of enough delay in raising a claim of a mistake was sufficient for the court to render a negative ruling. However, they are not the same, and the court in the *Western Energy* case, while ruling on the basis of the statute of limitations, was also ruling that the discrepancy between the contract for deed and the warranty deed in that case was not enough to establish the existence of a mutual mistake.

> Laches is a defense that can be invoked when the plaintiff has delayed in bringing a suit. But laches is not concerned merely with the fact of delay. It matters why the plaintiff delayed bringing the claim and what effect that delay had on the defendant. In doctrinal terms, the delay must be "unreasonable" and cause "prejudice." It is this focus on considerations other than the mere passage of time that strongly distinguishes laches from the statutes of limitations.[36]

Accordingly, there is a significant distinction between statutes of limitation and the doctrine of laches when applied to a case such as *Western Energy*, as reflected in the North Dakota Supreme Court's opinion in the case, and in the following statement:

> "Laches, a term for slackness or negligence, used particularly in law to signify negligence on the part of a person in doing that which he is by law bound to do, in allowing an unreasonable time to elapse in asserting a right, seeking relief, or claiming a privilege. Statutes of limitation specify the time within which various

the laxity with which they followed common law precedents."). The chancellor, who was the judge presiding over the chancery court, was entitled to modify the application of strict legal rules and grant relief if that seemed appropriate in the particular circumstances.

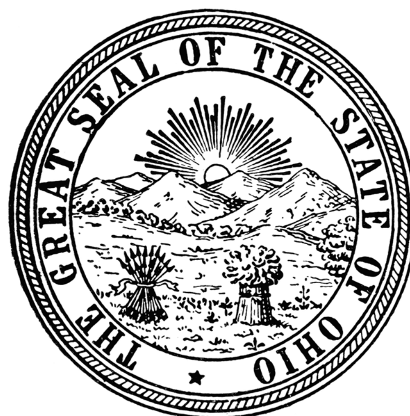
36. Samuel L. Bray. *A Little Bit of Laches Goes a Long Way: Notes on Petrella v. Metro-Goldwyn-Mayer, Inc., 67* VAND. L. REV. 2 (2014), *citing* 1 Dan B. Dobbs, LAW OF REMEDIES-EQUITY-RESTITUTION 103 (2d ed. 2013).

> classes of actions may be brought, and various statutes granting remedies, etc., impose a definite time within which legal action must be taken.[37]

The concept of "equity" is mentioned a number of times above,[38] though it is not feasible to attempt to discuss it in depth here. In a legal context, it suggests a system that recognizes that the law can work, to a limited extent anyway, with a reasonable amount of flexibility without damaging its authority. This was very well said nearly 100 years ago, with regard to property, by the great American legal scholar Roscoe Pound:

> More and more the tendency is to hold that what the law should secure is satisfaction of the owner's reasonable wants with respect to the property—that is those which consist with the like wants of his neighbors and the interests of society.[39]

37. ENCYCLOPEDIA BRITANNICA, *supra* note 27.
38. *See*, e.g., *supra* notes 14, 22, 25, 31 and 32.
39. ROSCOE POUND, THE SPIRIT OF THE COMMON LAW, 186 (1921).



Ohio

By: Gregory W. Watts & Matthew W. Onest[1]

I. Mineral Ownership

This section will discuss judicial decisions which seek to aid the determination of mineral rights ownership.

A. *The Ohio Marketable Title Act*

In recent years, as a result of Ohio's Utica shale boom, Ohio courts have confronted the issue of how to apply the Ohio Marketable Title Act.[2] As with many statutes, there are generally two questions to answer: (1) does the particular statute apply to the particular facts of the case? and (2) if the statute applies in the first instance, how does a court apply the statute to the particular facts of the case? Both

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2. *See* OHIO REV. CODE ANN. §§ 5301.47–5301.56 (West 2019).

questions about Ohio's Marketable Title Act and severed mineral interests were examined and explored in 2019.

The Seventh District Court of Appeals, which appears to have examined the most cases involving questions of severed mineral ownership, recently answered the first question in the affirmative, holding the Ohio Marketable Title Act applies to severed mineral interests. In *Stalder v. Bucher*, the severed mineral owners claimed the Ohio Marketable Title Act does not apply to severed mineral interests, meaning it would not extinguish severed mineral interests because the Ohio Dormant Mineral Act exists to abandon severed minerals, i.e. they argued the specific statute ("Dormant Mineral Act") controls over the general statute (the "Marketable Title Act").[3] The Seventh District rejected this argument and held both statutes are equally and separately applicable to severed mineral interests.[4]

As to the applicability of the Ohio Marketable Title Act to specific facts, the Seventh District Court of Appeals issued several decisions in close proximity to one another and which appear to be internally inconsistent on how to apply the statute to severed property interests.

In order to prevail on a claim that the Marketable Title Act extinguished certain property interests, one must show the interest to be extinguished predates the "root of title" for the particular property interest.[5] The "root of title" is defined as the "conveyance or other title transaction in the chain of title of a person, purporting to create the interest claimed by such person, upon which he relies as a basis for the marketability of his title, and which was the most recent to be recorded as of a date forty years prior to the time when marketability is being determined."[6]

Another section of the Ohio Marketable Title heavily litigated in 2019 and involving the "root of title" is Revised Code § 5301.49(A), which provides property interests are preserved, i.e. protected from extinguishment, if they are specifically referenced within the muniments of title. In late 2018, the Ohio Supreme Court adopted a

3. Stalder v. Bucher, No. 17 MO 0017, slip op. ¶¶ 11–19 (Ohio Ct. App. Mar. 3, 2019), *appeal denied*, 125 N.E.3d 937 (Ohio 2019).
4. *Id*. at ¶ 19 ("Because an oil and gas interest is subject to both the MTA and the DMA, the trial court did not err in finding the MTA applicable in this case.").
5. § 5301.50.
6. § 5301.47.

three-part test for determining whether an interest was specifically referenced under Revised Code § 5301.49(A).[7]

In early 2019, in three separate decisions, the Seventh District held that any reference to a severed mineral interest with a purported root of title, including general reservation language such as "reserving all oil and gas," prevented a party from claiming marketable title as against any severed mineral interests predating that root of title.[8] However, the Seventh District appears to have implicitly overruled itself in *Stalder*.[9]

Additionally, in *Hickman*, the Seventh District granted appellants' application for reconsideration and enacted a new rule for this reference-within-root issue—the void within chain-of-title rule. On September 25, 2019, the *Hickman* court reconsidered its previous opinion and offered a new justification for that decision.[10] It held that a court need not apply the *Blackstone* test to a purported repetition or reference within a root of title unless the record, meaning the evidentiary record before the court, contains all title documents within the chain-of-title from the date of severance forward.[11] The opinion goes further by essentially holding that the Marketable Title Act would not extinguish an interest absent those title documents being presented at evidence in a lawsuit seeking confirmation of extinguishment under the statute.[12] This appears to be an implicit, and possibly mistaken, holding that the statute operates once a lawsuit is filed.[13]

In a non-mineral rights case, the Sixth District Court of Appeals in *David v. Paulsen* further discussed how one determined the

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7. Blackstone v. Moore, 122 N.E.3d 132, 136 (Ohio 2018) ("The statute presents a three-step inquiry: (1) Is there an interest described within the chain of title? (2) If so, is the reference to that interest a 'general reference'? (3) If the answers to the first two questions are yes, does the general reference contain a specific identification of a recorded title transaction? Here, the answer to the first question is yes: the 1969 deed that constitutes the root of title recites that it is subject to the royalty interest. Thus, we turn to the second question: is the reference a 'general reference'?")

8. Hickman v. Consolidation Coal Co., 129 N.E.3d 1052 (Ohio Ct. App. 2019); Miller v. Mellott, 130 N.E.3d 1021 (Ohio Ct. App. 2019); Soucik v. Gulfport Energy Corp., No. 17 BE 0022, 2019 WL 549770, slip op. (Ohio Ct. App. Feb. 7, 2019).

9. *But see* Hickman v. Consolidation Coal Co., No. 17 CO 0012, 2019 WL 4894087 (Ohio Ct. App. Sept. 26, 2019).

10. *Hickman*, 2019 WL 4894087.

11. *Id.* ¶ 24.

12. *Id.*

13. *See* Warner v. Palmer, No. 14 BE 0038, 2017 WL 1102786, slip op. ¶ 34, (Ohio Ct. App. Mar. 27, 2017).

specific "root of title."[14] As previously discussed, the "root of title" is determined based, in part, on the following criteria: "which was the most recent to be recorded as of a date forty years prior to the time when marketability is being determined . . . ." The *David* court analyzed what is meant by "the time when marketability is being determined. In doing so, the court held that the date marketability is determined is the date on which the superiority of the property rights at issue is being asserted.[15]

However, the Seventh District determined that the forty-year period for severed mineral interests is essentially a rolling period, governed by the potential root of title documents.[16]

On June 19, 2019, the Seventh District Court of Appeals decided *Kilburn v. Graham*.[17] *Kilburn* involved the interpretation of the following mineral conveyance language—"the one-half part or share of their royalty of all [the oil] and gas in and under [the property]."[18] In 1919, Frieda and Chancy Ankrom owned the surface estate and one-half of the oil and gas royalty for 120 acres in Monroe County, Ohio. In May of 1919, the Ankroms conveyed "unto F .F Burkhart, A.C. and E.L. Peters and H.J. Cooper the one-half part or share of their royalty of all [the oil] and gas in and under [the property]."[19] The dispute involved the present surface owner of the property (the plaintiff) and the heirs of F.F. Burkhart.[20]

The trial court found the use of the term "the one-half" in the Ankrom conveyance meant they conveyed the entirety of their interest and that the conveyance consisted of three equal, undivided parts, meaning a total of one-sixth interest in the royalties was conveyed to F.F. Burkhart, A.C. and E.L. Peters, and H.J. Cooper.[21]

14. David v. Paulsen,—N.E.3d—, 2019 WL 2323846, ¶¶ 15–24 (Ohio Ct. App. 2019).
15. *Id.* at ¶ 20 ("We think it more appropriate to determine marketability as of the date that David and Sanders sought to enforce a purportedly-superior right to the property-which, in this case, was the date that they filed an action to enforce the Declaration of Restrictions against the Moores.").
16. Senterra Ltd. v. Winland, No. 18 BE 0051, 2019 WL 5544130, slip op. ¶¶ 53–58 (Ohio Ct. App. October 11, 2019).
17. No. 18 MO 0022, 2019 WL 2755129, slip op. (Ohio Ct. App. June 19,2019).
18. *Id.* at ¶ 10.
19. *Id.* ¶ 3.
20. *Id.* at ¶¶ 3, 7.
21. *Id.* at ¶ 13.

The Seventh District upheld the trial court on both points. As to the interpretation of "the one-half part or share of their royalty," the Seventh District provided little to no analysis to support its conclusion:

> At the time of the conveyance, the Ankroms owned an undivided 1/2 interest in the oil and gas royalty. The fact that the conveyance granted "the one-half part or share of their royalty" indicates that the Ankroms intended to convey their entire interest in the royalty. "[T]heir share," indicates that the Ankroms only owned a portion of the royalty, not the whole royalty. As they conveyed "the one-half part or share," the deed shows that the Ankroms intended to convey their entire interest in the royalty.[22]

Based on the scant amount of legal analysis, it is difficult to believe the holding of this case will offer much precedential value to other deed interpretation cases. However, if one is confronted with interpreting a conveyance involving fractional interests, this case may help provide a little guidance as to how to interpret said conveyance.

As to the number of shares conveyed by the Ankroms, the Seventh District held that the Ankroms conveyed three equal shares. The Seventh District relied, principally, upon the lack of a serial or Oxford comma between A.C. and E.L. Peters name.[23] The appellate court refrained from rewriting the deed to state either "F .F Burkhart, A.C., and E.L. Peters, and H.J. Cooper" or "F .F Burkhart, A.C. Peters, and E.L. Peters and H.J. Cooper."[24] The court further relied upon the fact that the grantees were grouped by last names, indicating three distinct groups of grantees.[25]

In *Windland v. Christman*, the Seventh District Court of Appeals analyzed how res judicata, which is comprised of claim and issue preclusion, may work when a surface owner sues a severed mineral interest owner's predecessors and a judgment has been rendered against those prior mineral owners.[26] In *Winland*, the

22. *Id*. at ¶ 24.
23. *Id.* at ¶ 30.
24. *Id.*
25. *Id*. at ¶ 31.
26. Winland v. Christman, No. 18 MO 0005, 2019 WL 2513801, slip op. (Ohio

putative mineral owners alleged to have acquired the severed mineral interest via inheritance from their father.[27] Their father had acquired the interest in 1944 via an auditor's deed.[28] That deed made specific reference to two of the original owners (Bentley and Watson).[29] In a previous lawsuit, the surface owner sued Bentley and Watson and "their unknown heirs, devisees and legatees."[30] The surface owner ultimately prevailed in that lawsuit, and the court of common pleas determined he owned the severed mineral rights.[31] Even though the putative mineral owners in *Winland* were not named in the previous lawsuit, the Seventh District still held they were bound by that decision. Thus, their claim of mineral ownership was barred based upon res judicata because they were in privity with the original mineral owners (Bentley and Watson).[32]

B. *The Ohio Dormant Mineral Act*

In *Gerrity v. Chervenak*, T. D. Farwell originally reserved oil and gas rights underlying a Guernsey County property in a 1961 deed.[33] Mr. Farwell's estate conveyed the reserved mineral rights to his daughter, Jane F. Richards, via a recorded certificate of transfer in 1965.[34] The certificate of transfer listed Ms. Richards as living at a Cleveland, Ohio address.[35] The reserved interest was not thereafter conveyed of record in Guernsey County.[36]

In 1999, the Chervenaks acquired the surface of the lands.[37] In 2012, the Chervenaks initiated abandonment procedures under the Dormant Mineral Act, sending notice of abandonment to Ms. Richards at the Cleveland address listed on the 1965 certificate of transfer via certified mail.[38] When certified mail failed, the Chervenaks served

Ct. App. June 14, 2019) *appeal denied*.

27. *Id.* at ¶ 52.
28. *Id.*
29. *Id.*
30. *Id.* ¶ 46.
31. *Id.* ¶ 43.
32. *Id.* ¶¶ 52–55.
33. Gerrity v. Chervenak**,** No. 18 CA 26, 2019 WL 2745501, slip op. ¶ 2 (Ohio Ct. App. June 28, 2019) *appeal docketed.*
34. *Id.*
35. *Id.* ¶ 15.
36. See *Id.*
37. *Id.* ¶ 3.
38. *Id.*

notice of abandonment via publication in a Guernsey County newspaper and then completed the abandonment process by filing a notice of failure to file.[39]

Timothy Gerrity, a resident of Franklin County, Ohio, and the sole heir of Jane F. Richards, claimed to be the rightful owner of the mineral interest.[40] Mr. Gerrity sued the Chervenak Family Trust, the then-owner of the surface estate, claiming that the abandonment procedures were invalid due to the Chervenaks' failure to exercise reasonable diligence to locate him and serve him notice.[41] The trial court found in favor of the Chervenak Family Trust.[42]

The Fifth District Court of Appeals upheld the trial court's decision in its entirety, determining that the Chervenaks' attempts to locate the heirs of Ms. Richards were reasonable.[43] The Fifth District noted Ms. Richards' address as being in Cleveland, Ohio as of 1965, and while she died in Broward County, Florida in 1997, there was nothing of record in Guernsey County or Cuyahoga County to point the Chervenaks to Florida.[44] After certified mail to the Cleveland address failed, the Chervenaks searched the recorder's and probate records in Guernsey County, Ohio (location of property) and Cuyahoga County, Ohio (last known address for Ms. Richards) and found nothing to indicate any other location for Ms. Richards or her heirs.[45]

The Fifth District held an exhaustive internet search for Ms. Richard's heirs was not warranted for several reasons: (1) Gerrity was an attorney in Franklin County, Ohio, with a different last name than Ms. Richards, the registered holder of the interest; (2) the Chervenaks searched recorder and probate records in both the county in which the property was located and the county of Ms. Richards' last known location; and (3) that search did not reveal any further addresses for Ms. Richards or her heirs.[46] The Fifth District determined that the Dormant Mineral Act did not contemplate a "worldwide exhaustive

39. *Id.* ¶ 19.
40. *Id.* ¶ 3.
41. *Id.* ¶ 4.
42. *Id.* ¶ 5.
43. *Id.* ¶¶ 24–27.
44. *Id.*
45. *Id.* ¶ 25.
46. *Id.*

search" for a holder, and on these facts, upheld the validity of the abandonment procedure.[47]

II. MINERAL EXPLORATION AND PRODUCTION

This section will discuss judicial decisions, legislation, and administrative law changes relating to mineral development.

A. *Recording Statutes Apply to Assignments of ORRI*

In *Talmage v. Bradley*, the United States District Court for the Southern District of Ohio had to decide, on summary judgment, whether Ohio's recording statutes apply to assignments or other conveyances of overriding royalty interests in oil and gas leases. More specifically, whether an unrecorded assignment or conveyance of an overriding royalty interest may be enforced against a subsequent lessee (meaning one who acquired the subject lease after the creation of the override).[48]

In April 1994, TransAtlantic Energy Corp., TransAtlantic Management Company, and TransAtlantic Gas Marketing, Inc. assigned various oil and gas leases.[49] The TransAtlantic-Eastern assignment was recorded in Belmont, Monroe, and Noble Counties in Ohio.[50] All of the leases assigned were described in one exhibit, meaning they were conveyed by one instrument.[51]

After the Transatlantic assignment, the assignment of the overriding royalty at issue, made to Ralph Bradley, was recorded in Monroe County and Belmont County.[52] Due to a clerical error, the assignment was not recorded in Noble County, despite it covering leases for Noble County properties.[53]

Eastern States, which acquired the leases from TransAtlantic and conveyed the override to Mr. Bradley, underwent a series of mergers, name changes, and intercompany transfers.[54] NCL

47. *Id.*
48. 377 F. Supp. 3d 799, 808 (S.D. Ohio 2019).
49. *Id.* at 803.
50. *Id.*
51. *Id.*
52. *Id*. at 804–05.
53. *Id*.
54. *Id*. at 805.

Appalachian Partners, LP eventually acquired Eastern's interest in the leases and wells.[55] NCL thereafter assigned the leases and wells to Northwood Energy.[56] The NCL-Northwood Assignment provided that Northwood acquired NCL's interest in the leases, subject to all overriding royalty interests of record.[57]

At the time Northwood Energy was acquiring NCL's interest, Northwood was also acquiring a 50% interest in the undeveloped portions of the leases, which TransAtlantic had originally retained when the leases and wells were originally conveyed to Eastern.[58] In 2012, Northwood Energy sold the deep rights to the leases, and other unrelated leases, to Gulfport Energy Corporation.[59] Gulfport subsequently sold some of the leases to Antero Resources Corporation.[60]

In early 2010, Northwood Energy received a series of emails from Joseph W. Haas of Reserve Energy Exploration, which detailed the terms of the Bradley override and provided a copy of the override assignment.[61] Northwood Energy had separately obtained due diligence information from another producer, which contained, in part, specific information relating to the Bradley override.[62] Additionally, in August of 2012, Ralph Bradley detailed his override in a communication with Northwood Energy.[63]

The primary questions before the court was whether Ohio's recording statutes applied to assignments of overriding royalties and if so, which of the statutes applied to such assignments?

By way of background, two Ohio recording statues were at issue in *Talmage*. The first, contained at Revised Code § 5301.09, specifically applies to oil and gas leases and interests related thereto.[64]

55. *Id.*
56. *Id.*
57. *Id.*
58. *Id.*
59. *Id.*
60. *Id.* at 807.
61. *Id.* at 805–06.
62. *Id.* at 806.
63. *Id.*
64. OHIO REV. CODE ANN. § 5301.09 (West 2019) ("In recognition that such leases and licenses create an interest in real estate, all leases, licenses, and assignments thereof, or of any interest therein, given or made concerning lands or tenements in this state, by which any right is granted to operate or to sink or drill wells thereon for natural gas and petroleum or either, or pertaining thereto, shall be filed for record and recorded in such lease record without delay…").

The second, contained at Revised Code § 5301.25, is Ohio's general recording statute, governing all conveyances of land, encumbrances on land, tenements, or hereditaments.[65]

Initially, it must be noted that the *Talmage* court did not choose one of the recording statutes. Instead, it analyzed the facts of the case under both statutes, ultimately determining it could not decide the applicability of the statutes on summary judgment.

As to the applicability of Revised Code § 5301.09, the court decided it could not determine the applicability of one of the statute's exceptions to recording—the exception that "the recording requirement is not applicable between the contracting parties."[66] Section 5301.09 of the Revised Code states, in pertinent part: "No such lease or license is valid until it is filed for record, ***except as between the parties thereto***, unless the person claiming thereunder is in actual and open possession."[67] The court's analysis focused on the emphasized language. First, the court held the statute applies to assignments or conveyances of overriding royalty interests, meaning such documents must be recorded in order to avoid a subsequent lessee from seeking to avoid the unrecorded override.[68] The court held it needed to determine whether Northwood could be "deemed as standing in the shoes of Eastern" because the Bradley override assignment was not recorded in Noble County (which was the county at issue in plaintiffs' claims seeking to avoid the override). This would therefore mean the "as between the parties" exception within Revised Code § 5301.09 was met.[69] After reviewing the various contracts and agreements, the court could not say the facts were undisputed on this issue and therefore refused to grant summary judgment to any party.

As to the applicability of Revised Code § 5301.25, the court likewise passed on giving summary judgment to any party because there was a factual dispute as to whether Northwood Energy Corporation (the first lessee to acquire the leases from the original lessee group) had actual knowledge of the unrecording overriding royalty when it acquired the leases.[70] The court examined numerous

65. OHIO REV. CODE. ANN. § 5301.25 (West 2019).
66. Talmage v. Bradley, 377 F. Supp. 3d 799, 810 (S.D. Ohio 2019).
67. *Id.* at 816 (emphasis added).
68. *Id.* at 817.
69. *Id.* at 810.
70. *Id.* at 815 ("In conclusion, the Court cannot make a final decision as to whether Northwood was a bona fide purchaser as there is a question of fact as to

pieces of evidence going to the issue of Northwood's knowledge of the Bradley override prior to its acquisition of the leases and wells. One should review that case in detail to examine the various pieces of evidence which relate to a purchaser's knowledge of an unrecorded overriding royalty.[71]

B. *Royalty Disputes*

The *Zehentbauer Family Land, LP v. Chesapeake Expl., L.L.C.* case is a class action royalty dispute alleging claims that Chesapeake Exploration, LLC wrongfully made royalty deductions against the landowners' lease royalties.[72] On appeal was the issue of whether the district court had properly granted class certification.[73] The specific issue on appeal relating to the class certification was whether the predominance requirement under Fed. R. Civ. P. 23(a)(2) was met when "plaintiffs argue that the netback method breached the leases because the defendants improperly deducted post-production costs in violation of the lease language prohibiting the defendants from deducting any expenses other than the plaintiffs' share of taxes."[74] Since the leases presented uniform royalty provisions, the Sixth Circuit held that plaintiffs met their burden of showing predominance of issues amongst the class members:

> If the plaintiffs prevail in showing that the defendants' uniform practice of deducting post-production costs to calculate royalties breached the leases, then the plaintiffs will have succeeded in proving liability. And conversely, if the defendants' method of calculating royalty payments by deducting post-production costs did not breach the leases, then all of the plaintiffs' claims will fail on the merits. This theory of liability, moreover, does not require an estimation of the

what Northwood knew at the time the NCL-Northwood Assignment was made.").

71. *Id.* at 812–14.

72. 935 F.3d 496, 499 (6th Cir. 2019) ("According to the plaintiffs, the defendants underpaid the royalties due to the plaintiffs during the years in question because the netback method (1) does not accurately approximate an arm's-length-transaction price, and (2) improperly deducts post-production costs from the price.").

73. *Id.*

74. *Id*. at 506.

> individual market prices of oil and gas at each well. Liability will turn solely on whether the leases permit the defendants to deduct post-production costs in calculating the royalties due to the plaintiffs (like the at-the-well rule), or whether the leases prohibit the defendants from deducting post-production costs (like the marketable-product rule).[75]

In upholding the class certification, the Sixth Circuit rejected defendants' contention that the court should fully examine and determine the merits of the parties' positions, i.e. whether the lessee was permitted to deduct post-production costs.[76] The Sixth Circuit determined that a merits analysis was not necessary to determine whether there was a predominance of issues amongst the class members because the leases were identical.[77]

The Sixth Circuit went further with the potential damage calculation plaintiffs could receive should they prevail on their theory of improper deductions, noting it relied on a rather straightforward calculation:

> Should the plaintiffs prevail in establishing that the defendants breached the leases by deducting post-production costs, then the plaintiffs' damages model must calculate what the royalty payments would have been had the defendants not deducted these costs in the royalty-payment calculations. This method will, in effect, base royalty payments solely on the prices at which the defendants' midstream affiliates sold oil and gas to downstream companies. Damages will then equal the difference between the royalty payments based on the downstream prices and the actual royalty payments calculated using the netback method, the latter having deducted post-production costs. This

75. *Id.*
76. *Id*. at 508.
77. *Id*. ("The defendants' argument challenging the plaintiffs' post-production-costs theory is a merits argument that is not germane to the predominance requirement of Rule 23(b)(3), so we decline to engage with it at the present time.").

> damages model is consistent with the plaintiffs' theory of liability.[78]

C. *Right to Inject Materials to Produce Oil and Gas*

In *Merino v. Levine Oil Enterprises, LLC*, the lessors brought a breach of contract claim against the lessee claiming a provision barring a lessee from injecting into the land prevented the lessee from injecting materials into the shale strata for purposes of facilitating hydraulic fracturing.[79] The paragraph at issue stated the following:

> It is agreed upon that we will not travel through the land to transport gas unless a well is drilled first on the leased land. It is also agreed upon that we will not inject the land. A separate deal in the future is possible if injection for disposal of wells is needed. The lessee has the right to purchase the well at salvage value if lessor chooses to abandon it in the future.[80]

On the other hand, the lessee claimed the paragraph relied upon by the lessors governed the use of disposal or injection wells and not production wells.[81] Instead, lessee claimed paragraph 1 of the lease governed producing wells and that hydraulic fracturing, including through the use of injecting water and chemicals, was permitted under that paragraph.[82]

Ultimately, the court of appeals sided with the lessee and held paragraph 1 governed the drilling of production wells and did not limit the lessee's ability to stimulate a well through hydraulic fracturing.[83] Instead, the paragraph specifically permitted use of injection of water and chemicals to aid in a well's production:

> That the Lessor * * * for the purpose of drilling, operation for, producing and the covenants and

78. *Id*. at 510.
79. Merino v. Levine Oil Enter., LLC, 131 N.E.3d 368, 371 (Ohio Ct. App. 2019).
80. *Id.*
81. *Id.*
82. *Id.*
83. *Id*. at 375.

> agreements hereinafter contained, does hereby lease exclusively unto the Lessee, for the purpose of drilling, operation for, producing and removing oil and gas and all the constituents thereof, ***and of injecting air, gas, brine and other substances from any sources and into any subsurface strata***.[84]

D. *Statutory Unitization and Breach of Lease*

On June 19, 2019, the Seventh District Court of Appeals issued a decision in *Paczewski v. Antero Resources Corp.*, which involved an oil and gas lessee's use of Ohio's forced unitization procedure.[85] The oil and gas lease in *Paczewski*, entered into in 1975, covered over 700 acres of property in Monroe County, Ohio and originally stated that the lessee could consolidate the leased lands with other lands to form development units not to exceed a total of 640 acres.[86] However, the original parties struck that clause by crossing out the text of the provision.[87] Ultimately, it appeared that sixteen shallow wells were drilled on the 700-plus acres, including a shallow well on the plaintiffs' property.[88]

Antero Resources Corp. eventually acquired the deep rights for the lease.[89] Antero attempted to negotiate an amendment to the lease, permitting Antero to pool or unitize the leased acreage with other acreage to form one or more units.[90] Those efforts failed and as a result, Antero filed an application with the Ohio Department of Natural Resources ("ODNR") for a statutory unitization order under Revised Code § 1509.28.[91] ODNR eventually approved the application and issued the unitization order including the leased

84. *Id.* at 371 (emphasis added).
85. Paczewski v. Antero Res. Corp., No. 18 MO 0016, 2019 WL 2722600, slip op. ¶ 2 (Ohio Ct. App. 2019). ("Appellants concede that the unitization order issued by the Division pursuant to R.C. 1509.28 ("Order") is valid, but argue nonetheless that the Order constitutes a breach of the oil and gas lease at issue in this case, as well as an unconstitutional taking of the property and minerals subject to the lease without just compensation.").
86. *Id.* ¶ 8.
87. *Id.*
88. *Id.* ¶ 9
89. *Id.* ¶¶ 9–10.
90. *Id.*
91. *Id.* ¶ 10.

acreage.[92] Plaintiffs appealed that decision to the Ohio Oil & Gas Commission and while that appeal was pending, they filed a lawsuit against Antero and the lessee owning the shallow rights.[93] Two of plaintiffs' claims were addressed by the Seventh District Court of Appeals' opinion—breach of lease based on the statutory unitization, meaning a breach of contract claim, and a claim that the unitization order violated the Ohio Constitution's takings clause.

The trial court dismissed all claims within the plaintiffs' complaint.[94] After that decision, the Fifth District Court of Appeals issued a decision in *Am. Energy-Utica, LLC v. Fuller*, holding that a lessee's use of statutory unitization to unitize an oil and gas lease, which stated "UNITIZATION BY WRITTEN AGREEMENT ONLY!" constituted a breach of contract.[95] Relying upon the *Fuller* decision, plaintiffs asked the trial court to vacate its dismissal of the plaintiffs' complaint.[96] The trial court denied the request and the plaintiffs thereafter appealed to the Seventh District Court of Appeals.[97]

Ultimately, the Seventh District Court of Appeals upheld the trial court's decision, thereby upholding the dismissal of the plaintiffs' complaint, in its entirety. As to the breach of contract issue, the Seventh District held that the lease at issue was silent as to whether Antero could unitize or pool the plaintiffs' lands because the original unitization/pooling provision was stricken.[98] The Seventh District adopted a rule, which was also adopted by the Tenth and Eleventh Appellate Courts, that provides a deleted or stricken lease clause renders the lease silent as to the subject matter of the stricken clause.[99] Thus, a stricken prohibition would mean the lease does not permit nor prohibit pooling.[100] The Seventh District relied on this rule to uphold the trial court's dismissal of the plaintiffs' breach of contract claim:

92. *Id.* ¶ 13.
93. *Id.* ¶¶ 14–15.
94. *Id.* ¶ 17.
95. American Energy-Utica, LLC. v. Fuller, No. 17 CA 000028, 2018 WL 3868119, ¶ 1 (Ohio Ct. App. Aug. 13, 2018).
96. Paczewski, 2019 WL 2722600, ¶ 21.
97. *Id.* ¶ 23.
98. *Id.* ¶ 34.
99. *Id.*
100. *Id.*

> Having considered the arguments of all parties, we find that the deletion of the voluntary unitization clause in the Lease renders it silent on the issue of unitization in any form. Because the Lease is silent with respect to either type of unitization, we conclude that the Order does not constitute a breach of the Lease, and that Appellants' first and second assignment of error have no merit.[101]

Further, the Seventh District relied on the plaintiffs' lease provision being stricken to distinguish the case from *Fuller*.[102]

The Seventh District also upheld the trial court's dismissal of the plaintiffs' takings claim. The court relied on the fact that Ohio provides less protections to subsurface mineral rights, and the Ohio Supreme Court previously held the pooling procedures constitute a proper exercise of the state's police power.[103] Furthermore, the appellate court held, per the unitization statute, no unitization order may be construed to have caused the title of the minerals to be transferred.[104] As a result, the court reasoned that Antero's unitization order left the plaintiffs' mineral interest intact, and the order was a mere regulation of mineral interests, not a taking without just compensation.[105]

E. *Paying Quantities and Conversion Post-Expiration*

In *Woods v. Big Sky Energy*, the Fifth District Court of Appeals rejected a producer's argument that its challenging the ODNRs refusal to accept a bond (required under Ohio law to operate an oil and gas well) from the producer's chosen insurance company.[106] After it rejected the producer's bond, the ODNR ordered the producer to cease producing all of its wells until a substitute bond was in place.[107] Instead of securing an alternate bond, which it admits it could have

101. *Id.* ¶ 35.
102. *Id.* ¶ 33.
103. *Id.* ¶¶ 39–40.
104. *Id.* ¶ 44.
105. *Id.* ¶ 45.
106. Woods v. Big Sky Energy, No. CT2017-0031, 2019 WL 645151 slip op. ¶ 6 (Ohio Ct. App. Feb. 6, 2019).
107. *Id.*

done, the producer "refused to do so as a matter of principle because Barr [the producer] disagreed with ODNR's decision."[108] Litigation between the producer and ODNR ensued and was still pending when *Woods v. Big Sky Energy*, which involved a paying quantities challenge by the lessor, went to trial.[109]

The trial court held the lease had expired and that the producer had converted the lessor's royalties and awarded the lessor $28,066.39 in compensatory damages.[110] The trial court issued a separate punitive damages award in the amount of $28,066.39, relying on the producer's concealment of "records which would demonstrate their failure to pay the full amount of royalties due" to lessor.[111]

The court of appeals upheld the trial court's decision that the lease had terminated and was not held under the lease's force majeure clause. The court relied on the fact the producer admitted it could have obtained alternate insurance, which would have permitted it to produce its wells, but chose to fight the State of Ohio "as a matter of principle, to demonstrate he was right and ODNR was wrong."[112] Ultimately, this decision means a producer that elects to not remedy the situation which led to a cease-production order from the ODNR while it is challenging the order does so at its own peril.

The producer did prevail on its appeal of the conversion claim and was given another opportunity to challenge the amount of the conversion damages. Here, the appellate court held the lessor was entitled to the converted unpaid royalties and not the revenue from the well.[113] Since the trial court gave a damages award based on the total revenue of the well and not the amount of royalties that would have been paid on that revenue under the terms of the lease, the appellate court found fault with the trial court's calculation and remanded the matter for further proceedings.[114] That trial would involve calculating the amount of "the converted royalties only."[115]

108. *Id.*
109. *Id.*
110. *Id.* ¶ 8.
111. *Id.*
112. *Id.* ¶ 17.
113. *Id.* ¶ 23.
114. *Id.*
115. *Id.*

OKLAHOMA

By: Mark D. Christiansen[1]

I. ROYALTY OWNER LITIGATION

A. *Tenth Circuit Court of Appeals Affirms Decision of the United States District Court for the Western District of Oklahoma Certifying a Modified Royalty Owner Class*

In *Naylor Farms, Inc. v. Chaparral Energy, LLC,*[2] the plaintiff royalty owners (collectively, Naylor Farms) contended that Chaparral systematically underpaid royalties on production from approximately 2,500 Oklahoma oil and gas wells by improperly deducting from royalty payments certain costs that the plaintiffs contended should have been borne solely by Chaparral under Oklahoma law. The district court granted Naylor Farms' motion seeking certification of a

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2. 923 F.3d 779, 784 (10th Cir. 2019).

class of royalty owners under Rule 23 of the Federal Rules of Civil Procedure.[3] In the present proceedings, Chaparral has appealed the district court's order granting class certification.[4]

Naylor Farms brought this suit alleging "claims for breach of contract, breach of fiduciary duty, fraud, unjust enrichment, and failure to produce in paying quantities."[5] Naylor Farms asserted that Chaparral breached what was described by the court as the "implied duty of marketability ("IDM")"[6] by improperly deducting what were described as "GCDTP-service costs"[7] from the royalty payments Chaparral made to Naylor Farms and other similarly-situated royalty owners. More specifically, certain midstream companies acquired title to or possession of the gas and natural gas liquids ("NGLs") at or near the wellhead, and then performed certain GCDTP services and sold the treated gas to downstream purchasers. In turn, the midstream companies deducted from the gross proceeds the amount they received from the downstream sales of production, i.e., the costs and fees associated with performing the GCDTP services. They paid Chaparral the resulting net proceeds. Chaparral then computed royalty payments "based on the *net proceeds* it receives from the midstream companies, rather than . . . based on the gross proceeds the midstream companies receive from the downstream sales."[8] Naylor Farms asserted that this approach to calculating royalty payments "requires royalty owners to bear the costs of transforming unprocessed gas into a marketable product" in breach of the IDM.[9]

3. Naylor Farms, Inc. v. Chaparral Energy, LLC, No. CIV-11-0634-HE 2017, WL 18754, at *9 (W.D. Okla. Jan. 17, 2017) ("[P]laintiffs' motion for class certification [Doc. #134], with the stated modifications, is granted. Plaintiffs' fraud claim will be excluded and the class will be limited to include those leases with "Mittelstaedt Clauses" listed on plaintiffs' Exhibit 29.") By later proceedings, the class definition was further revised to specify June 1, 2006, as the commencement date of the class period. Naylor Farms filed its Amended Class Definition (including the incorporation of the revisions referred to in the district court's Order of January 17, 2017) with the clerk of the district court. See Doc. 175, filed April 17, 2017, and Doc. 176, filed April 18, 2017.

4. *Naylor Farms*, 923 F.3d at 783.

5. *Id.*

6. *Id.* ("The IDM imposes upon lessees 'a duty to provide a marketable product available to market.'") citing Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1206 (Okla. 1998).

7. *Id.* (explaining that "GCDTP services" refers to the "gathering, compressing, dehydrating, transporting, and producing" of raw or unprocessed gas.)

8. *Id.* at 784.

9. *Id.*

Naylor Farms moved the court to certify a class of similarly situated royalty owners.[10] In opposition to that request, Chaparral argued that a determination of whether it breached the IDM would require an assessment of "individual issues, including the obligation created by each" individual oil and gas lease "and the gas produced from each" individual well,[11] as well as individual questions as to damages. Chaparral urged that those issues would predominate over any common questions. The district court disagreed and found that class certification was appropriate, except that it excluded Naylor Farms' fraud claim from the class certification order.[12]

Chaparral appealed. It asserted three primary arguments in support of its effort to obtain a reversal of the class certification order. First, Chaparral contended that *marketability* constitutes an individual question that predominates over any common questions. Second, it argued that distinctions in lease language also give rise to individual questions that likewise predominate in this case. Finally, Chaparral contended that there is a lack of evidence showing that it employs a uniform payment methodology to support certification. The Tenth Circuit proceeded to address "whether the district court abused its discretion in concluding that Naylor Farms satisfied Rule 23's certification requirements."[13]

The court first addressed the issue of marketability. The Tenth Circuit stated that "[i]t has been more than two decades since the Oklahoma Supreme Court ("OSC") has said anything meaningful about marketability,"[14] citing *Mittelstaedt v. Santa Fe Minerals, Inc, supra.* However, finding that *Mittelstaedt* did not provide guidance on the specific marketability questions presented in this appeal, the court stated that its "task is 'to predict how [the OSC] would rule' if it were to answer those questions."[15] The court then reviewed the principles and reasoning applied by the OSC in *Mittelstaedt*, and in the more recent Oklahoma Court of Appeals decisions in *Whisenant v. Strat Land Expl. Co.*[16] and *Pummill v. Hancock Expl. LLC.*[17]

10. *Id.*
11. *Id.*
12. *Id.*
13. *Id.* at 785.
14. *Id.*
15. *Id.*
16. 429 P.3d 703 (Okla. Civ. App. 2018).
17. 419 P.3d 1268 (Okla. Civ. App. 2018).

Chaparral contended that the district court erred in ruling "that (1) the question of when the gas became marketable can be answered via generalized, classwide proof and (2) as a result, the marketability question doesn't defeat predominance."[18] Chaparral additionally argued that the district court erred in treating marketability as a question of law, rather than as a question of fact. It asserted that a determination of the marketability question and whether Chaparral breached the IDM requires a "well-by-well analysis to determine whether any of the gas at issue was marketable at the wellhead."[19] Thus, the marketability question would defeat commonality and predominance.

However, the Tenth Circuit found that "the district court's ruling that marketability is subject to class-wide proof under the specific facts of this case is entirely consistent with the [Oklahoma Court of Civil Appeals'] decision in *Pummill*."[20] With regard to Chaparral's reliance on the *Whisenant* decision, the court noted Chaparral's insistence that "marketability can *never* be susceptible to classwide proof because it will always require an individualized assessment of the gas produced by each well."[21] However, the court emphasized the *Whisenant's* finding that certain factual issues were not susceptible to generalized proof according to reference to *that particular case*. "[T]he *Whisenant* court recognized that the OSC has declined to adopt a uniform test for determining when gas becomes marketable [and instead] left the issue open to resolution on a case-by-case basis."[22] The court left open the possibility that, in some cases, a determination might be made as to "when gas became marketable without undertaking an individualized inquiry into the quality of that gas."[23]

The court then found that "the facts in *Pummill* (and, by extension, the facts in this [*Chaparral*] case) fit comfortably in the space 'left . . . open' by *Whisenant*."[24] In light of the court's reading of *Pummill* and *Whisenant*, the Tenth Circuit predicted that the Oklahoma Supreme Court would hold:

18. *Naylor Farms,* 923 F.3d at 791.
19. *Id.* at 790.
20. *Id.* at 794.
21. *Id.*
22. *Id.*
23. *Id.* at 795.
24. *Id.*

> Under the facts of this case, a jury could determine when the gas at issue became marketable without individually assessing the quality of that gas; instead, a jury could make this determination based solely on the expert testimony that all the gas at issue was required to undergo at least one GCDTP service before it could "reach" and be "sold into" the pipeline market.[25]

The district court in *Chaparral* was found to have not abused its discretion by concluding that the question of marketability "*in this particular case* is subject to common, classwide proof for purposes of satisfying Rule 23's commonality and predominance requirements."[26]

The court next turned to Chaparral's contention that distinctions in oil and gas lease language present individual questions that predominated over any common questions. The district court below rejected that argument and found that "its decision to limit the class to leases containing a *Mittelstaedt* Clause renders such an individualized analysis unnecessary."[27] Most of the Tenth Circuit's discussion addressing this particular area of the appellants' arguments focuses on which issues were presented and preserved below. The Tenth Circuit was not persuaded that the district court abused its discretion in certifying the class despite the existence of what the court characterized as *minor* variations in oil and gas lease language.

Finally, on appeal, Chaparral urged that "Naylor Farms failed to demonstrate that Chaparral uses a uniform payment methodology to calculate royalty payments,"[28] and that such failure warranted the denial of class certification. However, while the existence of a uniform payment methodology, *alone*, was found by the court to be insufficient to meet the predominance requirement, the court rejected the notion that such a methodology is a necessary component for satisfying predominance. Moreover, the court noted that "[t]he fact that damages may have to be ascertained on an individual basis is not, standing alone, sufficient to defeat class certification."[29] Naylor

25. *Id.* at 781.
26. *Id.* at 795.
27. *Id.*
28. *Id.* at 798.
29. *Id.* at 798 (citing Menocal v. GEO Grp., Inc., 882 F.3d 905, 922 (10th Cir.

Farms presented evidence that individualized evidence will not be needed because its expert can determine damages on a class wide basis through the use of a model. The Tenth Circuit further noted that the district court could also, if needed, divide the class into subclasses for purposes of determining damages.[30] The district court was found to have not abused its discretion in concluding that individual questions about damages do not defeat predominance.

The Tenth Circuit Court of Appeals affirmed the district court's order granting Naylor Farms' motion for class certification subject to certain modifications of the class definition consistent with its opinion.

B. *Oklahoma Court of Appeals Reverses Certification of Class of Royalty Owners*

The Oklahoma Court of Appeals, in *Whisenant v. Strat Land Exploration Co.*,[31] reversed a decision of the District Court of Beaver County certifying a royalty owner *class*. Whisenant sued Strat Land alleging, on behalf of a proposed class of similarly situated royalty owners, the underpayment or non-payment of royalties on natural gas and its constituents from certain Oklahoma wells. The evidence showed that the putative class included approximately eighty-eight Oklahoma wells and approximately 1,000 royalty owners throughout the United States (¶ 15, note 11). The proposed class wells were located within, or adjacent to, Ellis, Harper, Beaver, and Texas Counties.[32]

Whisenant asserted that one of the issues of law and fact common to the proposed class was "whether gas [is] in Marketable Condition at the meter run/gathering line inlet."[33] He additionally argued, among other issues, that Strat Land paid royalties to him and to the proposed class using a common method based on the *net revenue* Strat Land received under its marketing contracts rather than

2018), *cert. denied,* 139 S. Ct. 143 (2018)).
30. *Id.* at 790.
31. 429 P.3d 703, 704 (Okla. Civ. App. 2018).
32. *Id.*
33. *Id.*

paying royalties based on the *gross amount* received by the midstream purchaser from its sale of the gas at interstate or intrastate markets.[34] The district court certified a class, subject to a series of exclusions not described below, consisting of all royalty owners in Oklahoma wells that:

> (a) [were] operated by [Strat Land]; (b) marketed by Strat Land to DCP Midstream (f/k/a Duke Energy Field Services)' and (c) that have produced gas and/or gas constituents (such as residue gas, natural gas liquids, helium, or condensate) from February 12, 2009 to the time Class Notice is given.[35]

The district court granted class certification under 12 O.S. § 2023(B)(3). Strat Land filed an interlocutory appeal of the class certification order.[36]

The court of appeals observed that the primary issue on appeal is whether there are common questions of law or fact. However, since the class was certified below under 12 O.S. § 2023(B)(3), the court noted the additional requirement that common issues *predominate* over other questions. Early in its discussion, the court stated that "[i]n the present case, class certification is inappropriate because a 'highly individualized' review of the facts pertaining to each of the numerous wells is necessary."[37] In concluding that the lower court's order granting class certification should be reversed, some of the key findings of the court of appeals included the following:

First, the court found that the standards in Oklahoma for determining whether certain types of post-production costs may be deducted in the computation of gas royalty payments, as recognized in the landmark case of *Mittelstaedt v. Santa Fe Minerals, Inc.*,[38] require a fact-intensive inquiry. That the trial court found "that Strat Land had

34. *Id.* at 705.
35. *Id.*
36. *Id.* at 705–06 (Under Oklahoma state court procedure, an order granting or denying class certification is "subject to a de novo standard of review by any appellate court reviewing the order." citing 12 O.S. Supp. 2014 § 2023(C)(2)).
37. *Id.* at 707 (The Oklahoma Court of Appeals cited in support of this conclusion its earlier decision in Strack v. Cont'l Res., Inc., 405 P.3d 131 (Okla. Civ. App. 2017), *cert. denied*).
38. *Id.*

a common corporate policy of not paying royalty on the gross value of the gas produced under the leases"[39] was insufficient to satisfy the predominance requirement of 12 O.S. § 2023(B)(3).[40] Rather, in discussing the complex analysis of determining whether the costs deducted in the computation of gas royalties were expenses necessary to make the gas a *marketable product*, the court of appeals stated that "highly individualized and fact-intensive review of each Class Members' claim would be necessary to determine if [the defendant] underpaid oil or gas royalties."[41]

Second, as a consequence of the above, the court of appeals rejected Whisenant's contention that "[c]lass action treatment will allow a large number of similarly situated individuals to prosecute their common claims in a single forum, simultaneously, efficiently, and without duplication of time, expense and effort on the part of those individuals, witnesses, the courts and/or [Strat Land]."[42] The court was likewise unpersuaded by Whisenant's contention that disposing of the case as a class action would "avoid the possibility of inconsistent and/or varying results in this matter arising out of the same facts."[43]

Third, the Oklahoma Court of Appeals declined Whisenant's assertion that "determination of the quality of gas and other facts pertinent to each well are susceptible to generalized proof."[44]

Fourth, the appellate court rejected the use of assumptions parallel to those used in the case of *Tyson Foods, Inc. v. Bouaphakeo,*[45] finding:

> [A]n assumption analogous to that forwarded by the employees in *Tyson*—*i.e.*, an assumption that, for each gas well within the proposed class, the royalty-

39. *Id*.
40. *Id.* at 708 (The court of appeals cited EQT Production Co. v. Adair, 764 F.3d 347, 366 (4th Cir. 2014) quoting "Even a plethora of identical practices will not satisfy the predominance requirement if the defendants'; common conduct has little bearing on the central issue in the litigation – in this case, whether the defendants underpaid royalties.").
41. *Id.* at 709 (citing Strack v. Cont'l Res., Inc., 405 P.3d 131 (Okla. Civ. App. 2017), and Foster v. Apache Corp., 285 F.R.D. 632, 638 (W.D. Okla. 2012)).
42. *Id.* at 710.
43. *Id.*
44. *Id.*
45. 136 S.Ct. 1036 (2016).

> valuation point and deductible costs can be set at the same average point and amount — is unwarranted.[46]

The court concluded that a class-wide determination based either on the variables as they existed with Whisenant's one well "or on an average sampling (*i.e.,* of gas quality, proximity of interstate pipelines, availability and proximity of processing plants, market realities, and so forth) would result in distorted and inconsistent awards to the various members of the class."[47] Citing *Tyson Foods, Inc. v. Marez,*[48] the court noted that "a judgment must be based upon evidence that establishes essential facts as probably, not merely possibly being true."[49]

Fifth, the court of appeals found "[a] reliance upon facts derived from other wells would be as impermissible as it would have been to determine liability in *Wal-Mart* based upon generalized evidence derived from other store managers."[50] The court of appeals rejected the plaintiff's assertion that class action certification was appropriate here based on their contention that the case would rely on admissible expert testimony to prove class-wide liability.

Finally, the court held that, even if Strat Land paid royalties to the members of the putative class using a common method, "the establishment of this common fact fails to resolve the issue of liability, an issue which remains individual rather than common."[51] The court specifically rejected Whisenant's contention that the alleged common method was either right or wrong, class-wide.

Concluding that the predominance and superiority requirements for class certification under 12 O.S. § 2023(B)(3) were not satisfied in this case, the court of appeals reversed the trial court's order granting class certification. Whisenant's subsequent petition for certiorari review by the OSC was denied by order issued on October 1, 2018. Mandate was issued on October 31, 2018.

46. *Whisenant*, 429 P.3d at 710–11.
47. *Id.* at 711.
48. 931 P.2d 760 (Okla. Civ. App. 1996).
49. *Whisenant*, 429 P.3d at 711.
50. *Id.*at 712.
51. *Id.*

II. Oil and Gas Lease Cancellation, Termination and Breach of Obligation Cases (Other Than Royalty)

A. *Court of Appeals Affirms the District Court's Finding that the Term Assignments at Issue in this Case Required the Commencement of the Well Within the Primary Term or any Extension Thereof, but did Not Require Completion of the Well within the Primary Term.*

In the case of *Blue Dolphin Energy, LLC v. Devon Energy Production Company, LP,*[52] the plaintiffs appealed the district court's order granting partial summary judgment in favor of the defendant Devon. This appeal was assigned to the Oklahoma Court of Appeals' accelerated docket under OSC Rule 1.36, and the case was considered based on the briefs filed with the district court, without appellate briefing.

The plaintiffs had entered into a Term Assignment of Oil and Gas Leases with Felix Energy, LLC (Devon's predecessor) in April 2014. In January of 2016, Felix merged with Devon, and Devon assumed the interests covered by the assignments. The Blue Dolphin plaintiffs alleged that the assignment:

> contained a "primary term of three (3) years, commencing on the first day of the calendar month that immediately follows the Effective Date, which was April 30, 2014." Plaintiffs [Blue Dolphin] state in the petition that the Assignments "required the assignee to complete a well capable of producing in paying quantities prior to May 1, 2017, which is the expiration of the primary term." [Blue Dolphin plaintiffs] contend that because Defendant failed to complete the well by May 1, 2017, the primary term in the lease "expired and the secondary term never commenced."[53]

The plaintiffs asserted that the leasehold interests covered by the subject assignment reverted back to the Blue Dolphin plaintiffs because Devon did not complete any wells by the end of the May 1,

52. Case No. 117,134 (Okla. Civ. App. May 30, 2019) (Not for Publication); Court Issue, 90 Okla. B.J. 707, 779–80 (Vol. 12) (June 22, 2019)

53. *Blue Dolphin Energy,* No. 117,134 at 2–3.

2017 primary term. They further alleged that Devon trespassed and interfered with the plaintiffs' right of exclusive possession of the property underlying the assignments of leases "by remaining on the property, continuing to conduct operations thereon, and extracting oil and gas from the property without Plaintiffs' authorization."[54] Finally, the plaintiffs argued that Devon continuously converted plaintiffs' crude oil and natural gas produced after the May 1, 2017 termination of the assignment of leases.

The Blue Dolphin plaintiffs moved for partial summary judgment in their favor, contending that: (a) the letter agreement and term assignments in favor of Felix, now Devon, unambiguously required completion of a well by May 1, 2017; (b) Devon did not complete a well by May 1, 2017; and (c) without a completed well by May 1, 2017, the term assignments expired and reverted to the plaintiffs.

Defendant Devon filed a combined: (a) response in opposition plaintiffs' motion for partial summary judgment; and (b) cross-motion for partial summary judgment in favor of Devon. It asserted, among other allegations, that the assignments were extended because Devon was engaged in drilling or completion operations as of May 1, 2017. The district court denied the plaintiffs' motion and granted the defendant Devon's cross-motion for partial summary judgment. The Blue Dolphin plaintiffs appealed.

The Oklahoma Court of Appeals first examined certain detailed provisions of the Term Assignment of Oil and Gas Leases and the related Letter Agreement of April 16, 2014 to assess whether those terms were ambiguous:

> "The mere fact the parties disagree or press for a different construction does not make an agreement ambiguous." *Id.* ¶ 14. "A contract is ambiguous if it is reasonably susceptible to at least two different constructions." *Id.*[55]

The court recited a series of additional rules of construction.

54. *Id.* at 3–4.
55. *Id.* at 9.

Blue Dolphin contended that the assignments required that Devon complete a well by May 1, 2017, in order to avoid the expiration of the assignments. Blue Dolphin further asserted that the language of the documents allowed Devon to continue to hold the lands so long as Devon commenced drilling or reworking operations within ninety days of the completion of the prior well as either a commercial producer or a dry hole.

However, Devon argued that since it was engaged in operations relating to its well through May 1, 2017 and those operations were ongoing through the completion of the well as a commercial producer in July of 2017, the primary term of the Term Assignment was extended through the completion.

At the hearing on the summary judgment motions, the trial court found that the primary term of the assignment extended past May 1, 2017, for the purpose of allowing Devon to complete its ongoing well operations. The court quieted title in favor of Devon. Blue Dolphin appealed.

The Oklahoma Court of Appeals agreed with the trial court that the assignments only required the *commencement* of the well within the primary term or any extension thereof, and the diligent continuation of drilling operations through the completion of the well as a commercial producer. The Court of Appeals affirmed the trial court's grant of partial summary judgment in favor of Devon and held that the primary term of the lease was extended under the language of the term assignment to allow Devon to continue ongoing drilling operations through to their completion.

III. OIL AND GAS CONTRACTS, TRANSACTIONS AND TITLE MATTERS

A. *Court Addresses Lawsuit by Private Business Group to Obtain a Copy of Public Real Estate Records from the County Clerks for Use in the Group's Business of Selling Rights of Access of its Copies of the Records*

The case of *TexasFile, LLC v. Boevers*[56] presented Texas File's appeal of the trial court's denial of its motion for summary judgment and that court's granting of summary judgment in favor of

56. 437 P.3d 211 (Okla. Civ. App. 2018).

the defendant County Clerks of Kingfisher County and Garvin County.

TexasFile is in the business of providing (via internet) remote access images of county land records to its subscribers. TexasFile, at the time of these proceedings, did business in Texas, New Mexico, and a few counties in Oklahoma. It had contracts with county officials in Blaine, Logan, Oklahoma, and Grady Counties, Oklahoma, under which it received digital land records for its business, and subscribers were allowed to access the images of the public land records.

On May 6, 2016, TexasFile submitted a request to the County Clerk of Kingfisher County, pursuant to the Oklahoma Open Records Act, for a "complete electronic copy of all the Kingfisher County land records that are currently available in electronic format." The court noted that TexasFile did not request the associated tract index. The communication specifically requested all records that were currently available on OKcountyrecords.com. The County Clerk did not respond to that request. TexasFile made a second request for an electronic copy of the land records on January 11, 2017.

On May 15, 2017, the County Clerk of Kingfisher County responded and denied Texas File's request, as described in more detail in paragraph five of the court's opinion.

TexasFile commenced the present declaratory judgment and mandamus action against the County Clerk of Kingfisher County "asking the trial court to enter an order determining TexasLink was entitled to an electronic copy of the Kingfisher County public land records maintained by the County Clerk, pursuant to the Oklahoma Open Records Act, and compelling the County Clerk of Kingfisher County to make available the land records of the Kingfisher County Clerk's office in an electronic format at a reasonable fee."[57]

The Kingfisher County and Garvin County Clerks joined in a Motion to Consolidate the present case with the separate lawsuit TexasFile had instituted on the same issues with regard to Garvin County. The district court treated that motion as a Motion to Intervene and granted intervention to the Garvin County Clerk.[58]

TexasFile filed a prompt Motion for Summary Judgment and Brief in Support that set out in detail the facts and law that TexasFile

57. *Id.* at 212–13.
58. *Id.* at 213.

urged in support of its contention that the requests it had made of the County Clerk were valid and should be honored. It contended that the case cited by the Kingfisher County Clerk, *County Records, Inc. v. Armstrong*, was inapplicable to this appeal. TexasFile asserted that the *Armstrong* case was distinguishable because it involved a request for the tract index, which was and is prohibited by statute. In contrast, TexasFile did not request a copy of the tract index. Additionally, the *Armstrong* court relied on the Abstractors Act, which is not involved in the present action.[59]

The Oklahoma Court of Appeals stated that "[t]he issue presented on appeal is whether a county clerk is required to provide an entity with an electronic copy of the county land records maintained by the county clerk when the copies will be used for commercial purposes."[60]

After proceeding through a detailed review of the issues and pertinent authorities, including the *Armstrong* case and the Open Records Act (which we will not attempt to fully outline in this case summary), the Court of Appeals held that the trial court did not err in denying TexasFile's request for the county land records of the two County Clerks in this case. It *affirmed* the granting of summary judgment in favor of the County Clerks of Kingfisher and Garvin Counties. The Court of Appeals also rejected TexasFile's assertion that the district court erred in allowing the County Clerk of Garvin County to intervene in this case. It found that the intervention at issue here met the requirements of Oklahoma's intervention statute and served the interest of judicial economy.

IV. SURFACE USE, SURFACE DAMAGES, OKLAHOMA SURFACE DAMAGES ACT, CONDEMNATION AND ENVIRONMENTAL CASES

A. *Interpretation of the Oklahoma Surface Damages Act as Applying to One Who Owns a Current Possessory Interest in the Surface*

59. *Id*.
60. *Id.* at 214.

The case of *Hobson v. Cimarex Energy Co.*[61] presented the question of "whether a vested remainderman is a *surface owner* under the [Oklahoma] Surface Damages Act."[62]

The OSC held that a vested remainderman is not a "surface owner" under the Act. Rather, for purposes of the Surface Damages Act ("SDA"), the term "surface owner" refers to one who holds a current possessory interest.[63]

The father in this case held a present "life estate" in the surface rights of the subject property in Canadian County, Oklahoma. The son held a "vested remainder interest" in the surface rights. Before drilling the subject well, the oil and gas lessee ("Cimarex") reached an agreement with the life tenant regarding surface damages under the SDA. After the well was drilled, Cimarex paid the life tenant in accordance with the agreement. The son (remainderman) sued Cimarex claiming that Cimarex should have negotiated with him as well under the SDA, and he was entitled to compensation under the Act. In response, Cimarex contended that a future interest owner does not qualify as a surface owner under the SDA. Cimarex asserted, in the alternative, that a "future interest owner does qualify as a surface owner and his cause of action is against the life tenant."[64]

The trial court held that a vested remainderman does not qualify as a surface owner under the SDA and dismissed the action with prejudice. On appeal, the Oklahoma Court of Civil Appeals disagreed and found that the SDA focuses on ownership rather than possession. It reversed and remanded the case for further proceedings. The Oklahoma Supreme Court granted Cimarex's petition for writ of certiorari.

The Oklahoma Supreme Court observed at the outset of its opinion that the present appeal "concerns the interpretation of 'surface owner' under the SDA."[65] It noted that "[t]he SDA defines 'surface owner' as 'the owner or owners of record of the surface of the property on which the drilling operation is to occur.'"[66] The court went on to

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61. No. 116,721, 2019 WL 4438043 (Okla. Sept. 17, 2019).
62. *Id.* at *1. *See* Surface Damages Act (codified as amended at OKLA. STAT. 52 § 318.2 (2010)).
63. *Id.*
64. *Id.*
65. *Id.*
66. *Id.* (citing OKLA. STAT. 52 § 318.2(2) (2010)).

make certain additional key findings and rulings in reaching its decision:

1.The SDA's definition of *surface owner* was found by the court to be ambiguous.[67]

2.The court observed that a vested remainder interest (which the son owned in this case) becomes possessory only when the preceding estate (here, the father's life estate) comes naturally to its end. "The lessee of a mineral lease is statutorily required to negotiate with the person or persons holding a current possessory interest in the surface of the land."[68] The court noted that, in this case, the son would not hold a possessory interest until his father's life estate came to a natural end.

3.The court observed that "[i]interpreting *surface owner* as requiring current possessory interest gives effect to legislative intent and promotes justice."[69] [Emphasis added] To require a possessory interest "does not modify the rights of the life tenants and vested remaindermen. A life estate entering a new minerals lease must still seek the remainderman's consent because removal of minerals will certainly affect the corpus of the property. [Citation omitted] Additionally, if the life tenant's transactions with the mineral leaseholder constitute an unreasonable injury to the remainderman's estate, the remainderman may bring a waste claim. [Citation omitted] A remainderman maintains recourse for the definite removal of corpus and potential waste from all other actions by the life tenant."[70]

4.The court concluded by recognizing, again, that the SDA's definition of "surface owner" was ambiguous.[71] "This Court is persuaded by the common meaning, expressed legislative intent, and interests of justice that the SDA's use of *surface owner* applies only to those holding a current possessory interest. Under the SDA, a mineral lessee must negotiate surface damages with those who hold a current possessory interest in the property. A vested remainderman does not hold a current possessory interest until the life estate has come to its nature end."

67. *Id.*at *3.
68. *Id.* at *2.
69. *Id.* at *3.
70. *Id.*
71. *Id.*

5.The Oklahoma Supreme Court vacated the decision of the Court of Appeals and affirmed the order of the trial court.

Note: Four (4) Justices concurred in the opinion, and a Fifth justice concurred specially. Four (4) justices dissented and three of those joined in the dissenting opinion written by Justice Darby.

B. *Tenth Circuit Affirms the Lower Court's Dismissal of the Proposed Class Action Lawsuit by Homeowners for Alleged Increases in the Cost of Insurance Due to Earthquake Issues*

In *Meier v. Chesapeake Operating L.L.C.,*[72] the plaintiff "homeowners brought a class-action lawsuit against operators of wastewater disposal wells for hydraulic fracturing operations, alleging the injection wells were significantly increasing seismic activity across larger portions of Oklahoma. The only damages the homeowners sought were the increased costs of obtaining and maintaining earthquake insurance."[73] More specifically, the homeowners sought to recover " '[t]he value of premiums paid to obtain earthquake insurance coverage; and/or . . . [t]he excess amount required to maintain earthquake insurance coverage after 2009,' as well as punitive damages."[74] The lawsuit was filed in the District Court of Payne County, Oklahoma. However, the defendants removed the case to the United States District Court for the Western District of Oklahoma under the Class Action Fairness Act. 28 U.S.C. § 1332(d).

The named defendants moved to dismiss the lawsuit based on the homeowners' alleged lack of standing and failure to state a claim. The federal district court held that (a) the homeowners did have standing to sue, (b) but it dismissed their suit for failure to state a claim. The court predicted that "the Oklahoma Supreme Court, if confronted with the issue, would find the relief requested by plaintiffs not legally cognizable under the circumstances present in the case at bar."[75] After its review of case law from Oklahoma and other states, the court found no authority to support an award of insurance premiums under the circumstances presented. The plaintiff homeowners appealed.

72. 778 F. App'x 561, 563 (10th Cir. 2019).
73. *Id.*
74. *Id.*
75. *Id.* at 564.

The Tenth Circuit initially addressed the homeowners' motion to certify stated questions in this appeal to the Oklahoma Supreme Court. Citing prior Tenth Circuit authority regarding certification of questions to the highest state court, [76] the court observed as follows:

> While we apply judgment and restraint before certifying . . . we will nonetheless employ the device [certification of questions to the state courts] in circumstances where the question before us (1) may be determinative of the case at hand and (2) is sufficiently novel that we fell uncomfortable attempting to decide it without further guidance.[77]

The Tenth Circuit declined the request that it certify the question to the OSC. First, the court found that it was highly unlikely, given the state of the legal authority, that the OSC would find in favor of the homeowners. It cited prior commentary to the effect that questions ought not to be certified if the answer is reasonably clear. Additionally, the court found it to be significant that the homeowners never requested certification of the question until the district court ruled against them on the merits. It found that the fact that a party only raises certification of the question after an adverse district court ruling "weighs heavily against certification."[78] Citing those two primary reasons, the Tenth Circuit declined to certify the question and, instead, proceeded to consider the merits of the question of "whether, under Oklahoma law, a homeowner can sue for increased insurance premiums absent any actual damage to property."[79]

The appellate court found that, while no Oklahoma authority specifically addressed the question at issue, "other states have consistently failed to recognize a cause of action for increased insurance premiums based on a tortfeasor's negligence."[80] The Tenth Circuit concluded that it was "highly unlikely the Oklahoma Supreme

76. *Id*.
77. *Id.* (quoting Pino v. United States, 507 F.3d 1233, 1236 (10th Cir. 2007)).
78. *Id.* at 565.
79. *Id.*
80. *Id.* at 566.

Court would allow proportional recovery for unmaterialized risk here, given its refusal to extend the loss-of-a-chance doctrine elsewhere."[81]

The Tenth Circuit engaged in further analysis of additional case law and concluded that, "[b]ecause the homeowners pleaded no legally cognizable claim for relief, the district court properly dismissed their complaint under Rule 12(b)(6)." The court declined to certify the question to the OSC and affirmed the district court's dismissal of the lawsuit.

C. *Tenth Circuit Affirms District Court's Exclusion of Two Expert Witnesses for the Plaintiff and Summary Judgment Ruling in Favor of Defendants*

The plaintiff in *Hall v. Conoco Inc.*[82] lived near the defendants' (ConocoPhillips) Oklahoma refinery as a child. "Roughly two decades later, Ms. Hall developed a form of leukemia," which was alleged to have resulted from her early exposure to the refinery's emissions of benzene.[83] Hall sued ConocoPhillips for negligence, negligence *per se*, and strict liability.[84] In her effort to prove the alleged link between the refinery's emissions and her development of leukemia, Hall proposed to present three expert witnesses at trial. The district court granted ConocoPhillips' motion to exclude the expert testimony of two of the proposed experts (*i.e.,* Dr. Gore and Dr. Calvey). The court also granted summary judgment to ConocoPhillips finding that, in the absence of the testimony of the excluded witnesses, Hall had not presented sufficient evidence linking her disease to benzene exposure.[85] Hall appealed.

The Tenth Circuit Court of Appeals began its review of the issues by reviewing the primary standards applicable to the exclusion of expert testimony. The court further observed that expert testimony must be determined to be reliable before the district court can admit the testimony. "The district court's assessment of reliability is review for an abuse of discretion,"[86] which includes an assessment of whether

81. *Id.* at 567.
82. 886 F.3d 1308, 1310 (10th Cir. 2018).
83. *Id.*
84. *Id.*
85. *Id.* at 1311.
86. *Id.*

the reasoning and methodology is both scientifically valid and applicable to a particular set of facts.

The appellate court reviewed and summarized the pertinent facts below in detail and concluded that Dr. Gore's proposed testimony could be justifiably regarded by the district court as unreliable "because of his failure to (1) justify ruling in benzene, or (2) rule out idiopathic[87] causes."[88] The Tenth Circuit found that the district court did not abuse its discretion in excluding Dr. Gore's opinion. With respect to Dr. Calvey, the court noted that her testimony "was excluded in part because Dr. Calvey had not 'adequately address[ed] the issue of exposure.'"[89] Hall did not challenge that rationale, which the Tenth Circuit found "[foreclosed] reversal of the exclusion of Dr. Calvey's testimony."[90]

Turning to the summary judgment ruling in favor of the defendants, Hall argued that circumstantial evidence (*e.g.,* "the presence of hydrocarbon leaks and odors in her neighborhood, groundwater contamination, a high benzene reading near her residence . . ."[91]) was sufficient to defeat summary judgment. However, the Tenth Circuit found that the circumstantial evidence did not "create a genuine issue of material fact on causation because of the need for expert testimony on the link between her disease and benzene exposure and quantification of Mr. Hall's exposure to benzene."[92] Without the testimony of Dr. Gore and Dr. Calvey, Hall could not meet her burden on the foregoing causation issues. The Tenth Circuit affirmed the district court's summary judgment ruling in favor of ConocoPhillips.

V. TRIBAL AND INDIAN LAND MATTERS

A. *Tenth Circuit Court of Appeals Affirms District Court's Finding of Trespass by Pipeline Owner Who Continued to Operate Pipeline After Expiration of its Limited Term Easement, but Reversed the*

87. Dr. Gore and other experts described an "idiopathic" disease as a disease in which the cause is unknown. *Id.* at footnote 1.
88. *Id.* at 1316.
89. *Id.*, citing *Hall v. Conoco Phillips,* 248 F.Supp.3d 1177, 1193 (W.D. Okla. 2017).
90. *Id.*
91. *Id.*
92. *Id.*at 1317.

Permanent Injunction Below Based Upon the Standard Applied in Granting the Injunction

The dispute presented in *Davilla v. Enable Midstream Partners L.P.*[93] arose in connection with the expiration of a twenty-year pipeline easement that covered certain Native American Indian allotted lands in Oklahoma. Enable Intrastate Transmission, LLC owned and operated a natural gas pipeline that traversed the lands. After the easement expired, Enable did not remove the pipeline, but rather continued to operate it. Enable ultimately approached certain allottees and sought a new twenty-year easement. It also applied to the Bureau of Indian Affairs ("BIA") for approval of a new easement. However, Enable failed to obtain approval for the proposed new easement from the allottees of a majority of the equitable interests in the land as required by applicable regulations.

As a result, the BIA cancelled Enable's right-of-way application. As Enable continued to operate the pipeline, a large group of individuals who held certain rights in the subject lands (the Allottees) filed suit in federal court alleging that Enable was trespassing on their land. They asked the court to enter an injunction compelling Enable to remove its pipeline. The parties were able to stipulate to most of the relevant facts. The Allottees moved for summary judgment on the issues of liability for trespass and injunctive relief. The court granted the Allottees' motion and requests for relief. Enable appealed.

Enable asserted two primary arguments on appeal. First, it argued that "the district court erred in granting summary judgment in favor of the Allottees on their trespass claims."[94] Second, Enable asserted that "the district court erred in issuing a permanent injunction to enforce the summary judgment ruling."[95]

In addressing the issues raised on appeal, the Tenth Circuit noted at the outset that "it is *the law*, not the material facts, that complicates this case."[96] The court further recognized that "[b]ecause we lack a federal body of trespass law to protect the Allottees' federal property interests, we must borrow state law to the extent it comports

93. 913 F.3d 959 (10th Cir. 2019).
94. *Id.* at 964.
95. *Id.* at 964–65.
96. *Id.* (Emphasis added by the court).

with federal policy."[97] The court went on to observe that "[t]he State of Oklahoma recognizes a right of action in trespass where one person 'actual[ly] physical[ly] inva[des] . . . the real estate of another without the permission of the person lawfully entitled to possession.'"[98] The Tenth Circuit concluded as follows:

> Our reading of Oklahoma law thus yields three elements constituting the Allottees' federal trespass claims. First, the Allottees must prove an entitlement to possession of the allotment. Second, they must prove Enable physically entered or remained on the allotment. Finally, they must prove Enable lacked a legal right—express or implied—to enter or remain. The stipulated facts already described definitively prove the first two elements.[99]

However, Enable took issue with the entry of summary judgment on the *third* element of the trespass claim. Enable contended that it had produced evidence of consent sufficient to prove a legal right to maintain the pipeline on the subject lands despite the expiration of the easement. More specifically, Enable showed that, in 2004, it had "obtained written consent forms from five of the thirty-seven individual Allottees in this case,"[100] showing that the five were willing to grant a new right-of-way for the pipeline in exchange for cash consideration.

While the Tenth Circuit noted that "evidence of a plaintiff's consent to a defendant's entry on the land will defeat liability in cases where the plaintiff's consent itself creates a right to enter or remain,"[101] it found that such evidence would not be sufficient in the present context.

> When it comes to maintaining a pipeline over Indian allotted land, however, Congress has dictated the prerequisites of a right to enter by statute. Enable thus

97. *Id.*
98. *Id.* at 966.
99. *Id.*
100. *Id.*
101. *Id.* at 967.

> has no legal right to keep a structure on the Allottees' land unless and until it secures a right-of-way for that purpose from the Secretary of the Interior. *See* 25 U.S.C. § 323. The Secretary must, in turn, have the approval of the relevant Indian stakeholders.[102]

The court found that the authorities cited by Enable fell short of holding "that one cotenant has no right of action for trespass under Oklahoma law when another cotenant—much less a *small minority* of co-tenancy interests—has agreed to a right-of-way easement."[103] Moreover, the court observed that, even if Oklahoma law were to provide that such evidence could defeat a trespass claim, "federal courts should only incorporate state rules of decision into federal claims to the extent those rules are consistent with federal law and policy."[104] The court concluded that Enable's view of the law would "frustrate federal Indian land policy, effectively robbing Indian allottees and the government of meaningful control over alienation."[105] Enable lacked a legal right to keep the pipeline in the ground.

The Tenth Circuit then turned to the second key argument of Enable with regard to the trespass claim—*i.e.,* that, even if the easement had expired, no duty to remove the pipeline ever arose because the Allottees never demanded that Enable remove it. Recognizing, again, that Oklahoma law would be incorporated into the subject federal claim so long as it did not frustrate federal policy, the court found that Oklahoma case law does not create a requirement that prior demand be made.[106] Rather, citing provisions of the Restatement (Second) of Torts, "the easement's expiration created a duty to remove the pipeline. . . Indeed, there would have been no sense in limiting the easement term to twenty years otherwise."[107]

The court concluded that "Enable acquired the pipeline *already knowing* the right-of-way would eventually expire. It

102. *Id.*
103. *Id.*
104. *Id.*
105. *Id.* at 967–68.
106. *Id.* at 969.
107. *Id.* The court did, however, discuss the easement holder's potential right to re-enter the property after the expiration of the easement for the purpose of removing the pipeline. *Id.* at 969–70.

therefore cannot—and indeed does not—claim it lacked notice of its duty to remove or intent to maintain the trespass."[108]

Finally, the Tenth Circuit reviewed Enable's challenge to the permanent injunction issued by the district court requiring Enable to remove the pipeline. As to this third basis for the appeal, the court agreed with Enable. The court recognized that a district court abuses its discretion when it bases its decision on an erroneous conclusion of law. Here, "the district court relied primarily on Oklahoma law—with supplemental authority from other federal courts—to conclude that 'equity will restrain [a continuing] trespass.' [citations omitted] As a result, it did not apply the usual four-factor test guiding federal courts' grant of permanent injunctive relief."[109]

The court found that, in determining whether to apply Oklahoma law or federal law in determining the standards for a permanent injunction, the court should consider:

> (1) "whether application of state law would frustrate specific" federal interests, (2) whether there is a "need for a nationally uniform body of law," and (3) other considerations such as whether "application of a federal rule would disrupt commercial relationships predicated on state law."[110]

The Tenth Circuit held that the district court erred because the circumstances in the present lawsuit indicated a distinct need for nationwide legal standards. "This uniform standard is necessary because the Secretary has undoubtedly approved easements over and across Indian land in multiple states."[111] The court noted that similar circumstances as those in the present dispute could lead other easement holders to be subject to an order of removal upon expiration of their easements. If the court did not apply a uniform standard in determining those issues, "an easement holder in Oklahoma and one in Kansas could be subject to differing permanent injunction standards

108. *Id.* at 970.
109. *Id.* at 971.
110. *Id.* at 972.
111. *Id.*

despite both receiving an easement from the Secretary of the Interior pursuant to the same federal program."[112]

> By failing to apply the federal courts' traditional equity jurisprudence to its remedy analysis, the [district court] committed an error of law and thus abused its equitable discretion. Accordingly, we must reverse the injunction order and remand for a full weighing of the equities.[113]

The Tenth Circuit Court of Appeals affirmed the district court's grant of summary judgment in favor of the Allottees. It reversed the entry of the permanent injunction, and remanded the case for further proceedings.

B. *United States Supreme Court Defers Decision to Allow for Additional Briefing and Oral Arguments in Pending Challenge to Tenth Circuit Court of Appeals Decision on Whether Congress Ever "Disestablished" the Muscogee (Creek) Nation Reservation*

In a decision issued August 8, 2017, in the appeal of the defendant's conviction for an alleged brutal crime, the Tenth Circuit Court of Appeals reached findings and conclusions that are of substantial concern to both the Oklahoma energy industry and the business community generally.[114] Murphy, a member of the Muscogee (Creek) Nation asserted in this appeal that he was wrongly prosecuted and convicted in the Oklahoma state courts for a crime that occurred in Indian Country (as defined in 18 U.S.C. §1151) over which the federal courts have exclusive jurisdiction. The state district court rejected Murphy's argument, finding that the crime had occurred on state land.

In a 126-page opinion addressing the issues on appeal, the Tenth Circuit found that, under the principles of *Solem v. Bartlett*,[115] Congress never *disestablished* the Creek Reservation. The case was

112. *Id.*
113. *Id.* at 971.
114. Murphy v. Royal, 866 F.3d 1164 (10th Cir. 2017).
115. 465 U.S. 463, 470 (1984).

remanded to the state district court to issue a writ of habeas corpus vacating *Murphy's* conviction and sentence.

Royal filed a Petition for Writ of Certiorari to the United States Supreme Court on February 6, 2018. The Petition was granted by the Court on May 21, 2018. Multiple amicus curiae briefs were filed. The parties and certain of the amicus participants presented oral argument to the Supreme Court on November 27, 2018.

On December 4, 2018, the Supreme Court directed the parties, the Solicitor General, and the Muscogee (Creek) Nation to file supplemental briefs addressing two questions:

> (1) Whether any statute grants the state of Oklahoma jurisdiction over the prosecution of crimes committed by Indians in the area within the 1866 territorial boundaries of the Creek Nation, irrespective of the area's reservation status. (2) Whether there are circumstances in which land qualifies as an Indian reservation but nonetheless does not meet the definition of Indian country as set forth in 18 U. S. C. §1151(a).[116]

The supplemental briefs were filed in late December 2018 and in January 2019. On June 27, 2019, the appeal in *Murphy* was restored to the calendar for re-argument but without specifying a particular date. As of the date this report was prepared, no specific date appeared to have been set for the presentation of the anticipated further oral arguments before the Court.

As a final note for those who are only lightly watching for further developments in this case, the case appears to be destined to experience at least three name changes during the several years it has pended on appeal. At the time the Tenth Circuit proceedings were filed and through the date the Tenth Circuit issued its decision, the case was entitled *Murphy v. Royal*.[117] Mr. Terry Royal was, at that time, the Warden of the Oklahoma State Penitentiary. When initial oral arguments were presented to the United States Supreme Court in

116. Order for Supplemental Briefing, Carpenter v. Murphy, 139 S. Ct. 626 (2018) (No. 17-1107) https://www.supremecourt.gov/qp/17-01107qp.pdf [https://perma.cc/2ZCZ-3W9X].
117. *Murphy*, 866 F.3d 1164.

the Fall of 2018, the case was entitled *Carpenter v. Murphy,*[118] because Mr. Mike Carpenter had assumed the role of Interim Warden of the Oklahoma State Penitentiary. By letter dated July 25, 2019, counsel for the Petitioner notified the Clerk for the United States Supreme Court that Mr. Tommy Sharp now serves as the Interim Warden of the Oklahoma State Penitentiary and will be automatically substituted as the Petitioner in this appeal in future proceedings.

VI. OTHER ENERGY INDUSTRY CASES

A. *Carried Working Interest Owner Sues to Recover its Claimed Share of Production Proceeds Under the Production Revenue Standards Act*

The court in *Abraham v. Palm Operating, LLC,*[119] was presented with a suit by Abraham alleging violations of Oklahoma's Production Revenue Standards Act, conversion, and restitution. Specifically, Abraham (a carried working interest owner in an oil and gas lease covering the Elias Kerns No. 2 well) sued the well operator (Palm) and the first purchaser (Pacer) for his alleged share of the proceeds from the sale of production. Abraham also sued the defendants for *interest* on the unpaid proceeds based on the alleged violation of the Production Revenue Standards Act ("PRSA"),[120] actual and punitive damages for conversion, and for restitution. The first purchaser, Pacer, denied liability and asserted, as affirmative defenses, the expiration of applicable statutes of limitation, laches, and waiver. Pacer further alleged that Abraham lacked clear marketable title, and that any failure by Pacer to make payment was due to Abraham's negligence or lack of diligence, as well as error by the operator Palm or prior operators.

The trial court granted summary judgment in favor of Abraham for $22,859.52 in production proceeds plus 12% interest, costs, and attorney fees. The purchaser, Pacer, appealed.

The Oklahoma Court of Appeals noted at the outset of its decision, in footnote 2, that the parties disputed whether Abraham's

118. Brief for Petitioner at 2, Carpenter v. Murphy, 139 S. Ct. 626 (2018) (No. 17-1107).
119. 447 P.3d 486, 487 (Okla. Civ. App. 2019).
120. *Id.*

ownership[121] interest was properly characterized as a "carried working interest" (notwithstanding the fact that the assignment in Abraham's favor stated that it was assigning a carried working interest). However, the court stated that the "type of ownership interest Abraham has is not material to this dispute."[122]

As for the primary issue presented in the appeal, the court found that one of the most important facts on appeal was that the parties agreed that at Palm's (the operator's) direction, the purchaser (Pacer) paid to Palm the working interest proceeds for the production the purchaser took from the well. Pacer asserted that it had no liability for the production proceeds after it paid them to the producing owner/operator Palm, pursuant to 52 O.S. 2011, §570.10(C)(1). The court further noted that the evidentiary materials before the court showed that Palm was the producing owner under the PRSA.

Abraham additionally argued that Section 570.10(C)(1) did not apply to this case "because, according to Abraham, while Palm may have been the producing owner of *some* of the production, it was not the producing owner of the portion of the production attributable to Abraham's interest."[123] Rather, Abraham was the owner of that production. After discussing the operation of the PRSA provisions in further detail, the Court of Appeals concluded:

> The evidentiary materials in the record show that Abraham was not the operator or producing owner and that Palm was the operator and producing owner. Abraham has not disputed Pacer's assertion that it paid the proceeds of production to Palm and therefore, under §570.10(C)(1), Pacer has discharged its liability for payment of proceeds of production. Pacer was therefore entitled to judgment as a matter of law on all of Abraham's claims against Pacer.[124]

Finally, in apparent indication as to the reason why Abraham pursued recovery against the purchaser of production with greater effort than the operator, the court advises in footnote 3 of its opinion

121. *Id.* at 488 n.2.
122. *Id.*
123. *Id.* at 489.
124. *Id.*

that, before this case was filed, Palm's assets had been placed in receivership in an action filed by a bank in another county, and Palm's predecessor in title had sought bankruptcy protection. Abraham asserted that he dismissed his claims against Palm. In contrast, Pacer contended that Abraham's claims against Palm were simply stayed.[125]

125. *Id.* at 488 n.3.

OREGON

Eric L. Martin[1]

I. INTRODUCTION

Even though no oil and only a small quantity of natural gas is produced in Oregon, the Oregon Legislature enacted bans in 2019 on hydraulic fracturing until 2025 and on using Oregon's territorial sea for oil and gas activities. Beyond that legislation, though, legal developments in Oregon this year concerning the oil and gas industry focused on downstream issues.[2]

II. CASE LAW

A. *Decision Awaited in U.S. Constitutional Climate Change Case*

Juliana v. United States is an Oregon lawsuit alleging that federal fossil fuels policy over the last fifty years constituted a deprivation of the plaintiff students' rights under the United States Constitution. Although the United States Supreme Court briefly stayed the case in late 2018 from going to trial pending its decision on

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2. For a broader look at oil and gas law in Oregon, *see* Eric Martin & Jerry Fish, *Mineral Rights*, *in* OR. REAL EST. DESKBOOK 42 (2015).

a writ of mandamus,[3] the United States Supreme Court ultimately denied the requested mandamus relief, concluding that the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") could grant the requested relief.[4] By the end of 2018, the Ninth Circuit had denied the federal government's request for a writ of mandamus but had granted an interlocutory appeal. The Ninth Circuit heard oral argument on the appeal in June 2019, and as of the date of this writing, a decision has not been issued.

B. *Oregon Clean Fuels Program Rules Upheld*

Oregon's Clean Fuels Program ("CFP") is intended to reduce greenhouse gas emissions from transportation fuels in Oregon to at least 10% lower than 2010 levels by 2025.[5] In *Western States Petroleum Ass'n v. Envtl. Quality Comm'n*, the Oregon Court of Appeals upheld the CFP rules the Environmental Quality Commission ("EQC") had adopted in 2015. The rules were upheld against two challenges: (1) that the EQC had failed to consider legislatively-imposed factors; and (2) that the rules constituted a tax on motor vehicle fuel, which the Oregon Constitution requires be used for highway construction and maintenance.[6] ORS 468A.266(5) calls for the EQC to "evaluate," among other things, "safety; the potential adverse effects to public health, the environment, and air and water quality; and the potential adverse effects to the generation and disposal of waste in the state" when promulgating CFP rules.[7] The court concluded that the EQC had evaluated all but one of these factors for the 2015 rules because they were addressed in a 2011 report listed on an EQC meeting agenda and described in the agenda as "documents relied on for rulemaking."[8] As to the factor that was not addressed in the 2011 report, the court found the issue moot because in 2017 the EQC had readopted the 2015 rules with a finding addressing the outstanding factor.[9] The court then turned to whether CFP credits constitute a "tax levied on . . . the distribution [or] importation . . . of motor vehicle fuel," which are subject to spending limitations under the Oregon Constitution.[10] Because the proceeds from the sale of CFP credits

3. *See* Eric L. Martin, *Survey on Oil & Gas: Oregon*, 5 *TEX. A&M J. OF PROP. L.* 123, 124–25 (2018–2019) (summarizing Juliana v. United States, 339 F. Supp. 3d 1062 (D. Or. 2018)).

4. Order in Pending Case, *In Re* United States, 586 U.S. ___ (Nov. 2, 2018) (No. 18A410), https://www.supremecourt.gov/orders/courtorders/110218zr2_8ok0.pdf [https://perma.cc/VEE3-42EC].

5. OR. ADMIN. R. 340-253-0000(2) (2017). The CFP was upheld in 2018 against a Dormant Commerce Clause challenge. *See* Martin, *supra* note 3, at 123–24 (summarizing Am. Fuel & Petrochemical Mfrs. v. O'Keeffe, 903 F.3d 903 (9th Cir. 2018)).

6. 439 P.3d 459 (Or. Ct. App. 2019).

7. *Id.* at 466.

8. *Id.* at 467.

9. *Id.* at 469.

10. *Id.* at 470.

are not paid to the state, the court concluded that the CFP does not constitute a "tax" for purposes of that provision in the Oregon Constitution.[11]

III. ENACTED LEGISLATION

A great deal of legislative attention and effort in 2019 focused on the "cap-and-invest" concepts in House Bill 2020. That effort ultimately fell short, but other laws related to energy policy in Oregon were enacted in 2019.

A. *Hydraulic Fracturing Banned*

Following a series of unsuccessful efforts over the years, hydraulic fracturing was banned beginning on June 17, 2019 and continuing until January 2, 2025.[12] House Bill 2623 defined hydraulic fracturing as "the drilling technique of expanding existing fractures or creating new fractures in rock by injecting water, with or without chemicals, sand or other substances, into or underneath the surface of the rock for the purpose of stimulating oil or gas production." Wells drilled for natural gas storage or geothermal energy production and existing coal bed methane wells are exempt from the ban.

B. *Offshore Drilling Banned*

In 2010, the Oregon Legislature enacted a ten-year moratorium on oil and gas leasing in Oregon's territorial sea (i.e., within three miles from the coast).[13] Following moves by the Trump Administration to potentially lease part of the Outer Continental Shelf (i.e., three or more miles from the coast) off the Oregon coast for oil and gas development and building upon Governor Brown's executive order last year,[14] in 2019 the Oregon Legislature amended ORS 274.705 to prohibit leasing Oregon's territorial sea for development that would support oil and gas activities on the OCS and eliminate the ten-year sunset on the existing leasing moratorium.[15]

C. *Railroad Oil Spill Planning Required*

To address concerns associated with transporting oil by rail,[16] the Oregon Legislature imposed additional regulatory requirements on railroads that own or operate "high hazard train routes" in Oregon.[17] A "high hazard train route" exists

11. *Id.* at 471.
12. 2019 Or. Laws Ch. 406.
13. 2010 Or. Laws Ch.11.
14. *See* Martin, *supra* note 3, at 127–28. State agencies were directed in 2018 by Executive Order No. 18-28 "to oppose the exploration and production of oil or gas off the Oregon Coast, including on the OCS, and to prevent the development of any infrastructure associated with offshore oil or gas drilling."
15. 2019 Or. Laws Ch. 14.
16. *See generally* Martin, *supra* note 3, at 124.
17. 2019 Or. Laws Ch. 581.

when rails that "abut[] or travel[] over navigable waters, a drinking water source or an inland location that is one quarter mile or less from the waters of the state" are used for the transport of a train containing either (1) a continuous line of at least twenty tank cars holding petroleum or petroleum products; or (2) at least thirty-five tank cars holding petroleum or petroleum products anywhere within the train. In that situation, among other things, such railroads must now have an Oil Spill Prevention and Emergency Response Plan (also known as a contingency plan) for responding to spills of petroleum or petroleum products, with such plan approved by the Oregon Department of Environmental Quality. In addition, such railroads must demonstrate their financial ability to pay the clean-up costs for a "worst case spill," with those costs being based on a minimum cost of $16,800/barrel of such a spill. This law also authorized the collection of additional fees on such railroads.

D. *Acquisition of Renewable Natural Gas Encouraged*

Oregon natural gas utilities now have statutory authorization to acquire renewable natural gas ("RNG") in increasing quantities for their retail customers with a target of having RNG constitute 30% of the natural gas supplied by large utilities by 2045.[18] RNG, for purposes of enacted Senate Bill 98, includes any of the following that meets pipeline quality standards or transportation fuel grade requirements: (1) methane released from the biological decomposition of organic materials; (2) hydrogen derived from renewable energy sources; or (3) methane derived from any of the aforementioned or from waste carbon dioxide. The Oregon Public Utilities Commission must adopt rules to implement the statute by July 31, 2020.

E. *State Commitment to Purchase Zero-Emission Vehicles*

Through a 2017 executive order, Governor Brown established, among other things, a goal of having at least 50,000 registered and operating electric vehicles in Oregon by 2020.[19] To advance the utilization of "zero-emission vehicles," which includes plug-in hybrids, state agencies are now required, with some exceptions, to purchase or lease zero-emission vehicles: (1) for at least 25% of new state light-duty vehicles by 2025; and (2) for all new state light-duty vehicles starting in 2029.[20] It also established statewide goals for zero-emission vehicle use and sales, including that by 2035 at least 90% of all new motor vehicles sold each year in Oregon will be zero-emission vehicles.

18. 2019 Or. Laws Ch. 541.
19. Exec. Order No. 17-21 (Nov. 5, 2017), https://www.oregon.gov/gov/Documents/executive_orders/eo_17-21.pdf [https://perma.cc/P6LP-U8QK].
20. 2019 Or. Laws Ch. 565.

PENNSYLVANIA
RECENT DEVELOPMENTS IN PENNSYLVANIA JURISPRUDENCE RELATED TO OIL AND GAS LEASING AND CONVEYANCING

Ross H. Pifer[1]

Pennsylvania is the largest producer of shale gas in the United States and is the second-largest natural gas-producing state overall.[2] Owing to its strategic location atop the Marcellus and Utica Shale Formations, Pennsylvania's position as a major natural gas producer is relatively new. Just a little over a decade ago, Pennsylvania ranked

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2. *See Shale Gas Production*, U.S. ENERGY INFO. ADMIN., available at https://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm [https://perma.cc/G3F4-HEEY] (last visited Nov. 13, 2019) (indicating that Pennsylvania had produced 5,365 Bcf of natural gas in 2017); *See also Natural Gas Gross Withdrawals and Production*, U.S. ENERGY INFO. ADMIN., available at https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm [https://perma.cc/JW26-ZZ28] (last visited Nov. 13, 2019) (indicating that Texas had produced 7,847,102 MMcf while Pennsylvania had produced 6,210,673 MMcf of natural gas in 2018).

sixteenth among states in total natural gas production.[3] With this rapid rise in the amount of natural gas development, there has been a corresponding increase in activity in courtrooms across Pennsylvania—both in state and federal courts. As a result, Pennsylvania oil and gas law has evolved within a number of different legal areas, with leasing and title issues perhaps being among the most frequent—and most important—topics that have been addressed by courts. This survey will address the 2019 reported judicial opinions issued by state courts in Pennsylvania that address oil and gas leasing and title issues.

I. PAYMENT IN LIEU OF FREE GAS

During Pennsylvania's long history of conventional oil and gas development, landowners have often sought lease provisions that provided them with free natural gas for use in home heating —a valuable benefit during cold Pennsylvania winters—when wells were drilled on their properties. In these free gas lease provisions, a landowner typically receives up to a specified quantity of natural gas at no cost and in some instances, leases permit the operator to provide payment of a market value price in lieu of providing free gas. In *Mitch v. XTO Energy*,[4] the Pennsylvania Superior Court provided an interpretation of a payment in lieu of free gas clause in an oil and gas lease. Raymond Mitch owned a 53.28-acre tract of real estate in Butler County, and in 2012, he executed an oil and gas lease with XTO Energy.[5] This lease provided for the payment of a bonus, 18% royalties, and an additional payment equal to the market value of 300,000 cubic feet of natural gas if certain conditions were satisfied.[6] The specific conditions that needed to be satisfied in order to trigger the additional payment to the surface estate owner were that a well was "drilled on the lease premises;" that the well was "producing in

3. *See* Ross H. Pifer, *What a Short, Strange Trip It's Been: Moving Forward After Five Years of Marcellus Shale Development,* 72 U. PITT. L. REV. 615, 619, n.28 (2011) (noting the top sixteen natural gas-producing states in 2005 according to data from the U.S. Energy Information Administration).

4. Mitch v. XTO Energy, Inc., 212 A.3d 1135 (Pa. Super. Ct. 2019).

5. *Id.* at 1137.

6. *Id.*

paying quantities;" and that "the surface owner ha[d] his primary residence on the lease premises."[7]

XTO Energy did not construct a well on the Mitch property. Mitch's acreage, however, was pooled together with other leases, and a well was constructed within the pooled acreage on a neighboring property.[8] The well that was drilled on the neighboring property was a horizontal well that traversed through the subsurface estate of Mitch's property, but there was no activity at all on Mitch's surface estate.[9] Following the drilling of this well, Mitch filed suit seeking a declaration that he was entitled to a payment in lieu of free gas pursuant to the terms of his lease.[10] The Butler County Court of Common Pleas rejected his claim, granting a summary judgment in favor of XTO Energy.[11]

In Mitch's appeal of this decision, the Superior Court determined that a *de novo* review was appropriate because the issue was one of contract interpretation.[12] The parties agreed that the relevant well met the producing in paying quantities standard, and Mitch's primary residence was located on the lease premises. Thus, the issue for the court to resolve was limited to an interpretation of the meaning of the phrase "drilled on the lease premises."[13] Mitch argued that the horizontal well drilled through his subsurface estate was within the lease premises.[14] XTO Energy countered that the lease required the well to be drilled on the surface estate for the lessor to be entitled to receive the payment in lieu of free gas.[15] The Superior Court accepted the argument of XTO Energy and concluded that the parties intended for the language "drilled on the lease premises" to mean drilled on the surface estate of Mitch's property. According to the court, "[i]t is unreasonable to find that the parties intended to compensate a **surface owner**" (emphasis in original) for a well located on the surface estate of another property.[16]

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7. *Id.*
8. *Id.*
9. *Id.*
10. *Id.*
11. *Id.* at 1138.
12. *Id.*
13. *Id.* at 1139.
14. *Id.* at 1140.
15. *Id.*
16. *Id.* at 1141.

II. SCOPE OF SURFACE ESTATE ACCESS

In *Porter v. Chevron Appalachia*,[17] the Pennsylvania Superior Court addressed another issue relating to the surface estate, this time reviewing the scope of the grant conveyed in an oil and gas lease. There, the Superior Court affirmed the grant of a preliminary injunction confirming the right of a drilling company to utilize the surface estate for pre-drilling activities. In 2002, the Porters granted an oil and gas lease on their seventy-six-acre tract to Atlas America, Inc. ("Atlas").[18] Following the execution of the lease, Atlas drilled conventional vertical wells on the property.[19] By virtue of its acquisition of Atlas assets, Chevron assumed control over the lease in question, and in 2017, Chevron notified the Porters of its intention to construct a well pad on the property that would be utilized for the extraction of oil and gas, including from neighboring properties.[20] After the Porters filed litigation objecting to this use of their property, Chevron continued its pre-drilling activities, and its personnel arrived on the property to mark the proposed drilling location.[21] While this activity was underway, Mr. Porter informed the Chevron personnel that they should "get off [the] property while the getting's good." Chevron personnel interpreted this as a threat and vacated the property.[22] Chevron then filed a motion for an injunction to prohibit the Porters from restricting their pre-drilling operations on the property.[23] On November 29, 2017, the Fayette County Court of Common Pleas granted the requested injunction, and an appeal ensued.[24]

The Superior Court reviewed the prerequisites for the grant of a preliminary injunction.[25] The court opined that reasonable grounds existed to support the conclusion that Chevron would suffer

17. 204 A.3d 411 (Pa. Super. Ct. 2019).
18. *Id.* at 414.
19. *Id.* at 415.
20. *Id.*
21. *Id.*
22. *Id.*
23. *Id.*
24. *Id.* at 416.
25. *Id.*

irreparable harm if the injunction was not granted.[26] Specifically, the Superior Court noted the lower court's findings that the failure to grant the requested injunction would impact other drilling plans and that added delay was particularly troublesome because some activities could not be performed in the winter months.[27] The Superior Court also agreed that the testimony supported a finding that it was "impossible to quantify" Chevron's damages caused by delay.[28] With regard to the issue of who was altering the status quo among the parties, the Superior Court concluded that it was the Porters who were altering the status quo by preventing Chevron's "contractual right of access."[29] Thus, the injunction restored the parties to the status quo position according to the court.[30] As such, the Superior Court affirmed the lower court ruling, noting that the injunction was limited to pre-drilling activities undertaken to prepare a permit application with the Department of Environmental Protection.[31]

III. CONVEYANCE OF MINERAL ESTATE THROUGH DEED IN LIEU OF CONDEMNATION

Horizontal drilling, together with hydraulic fracturing, is an essential technology for the extraction of shale gas.[32] The widespread use of horizontal drilling has expanded the types of real estate that have value for purposes of natural gas extraction. For example, there now is interest for natural gas development in the subsurface estate beneath roadways. In *O'Layer McCready v. Department of Community and Economic Development*,[33] the Pennsylvania Commonwealth Court addressed the ownership of oil and gas rights beneath a public roadway. Sarah O'Layer McCready acquired title to a parcel of land in Lawrence County in 1978.[34] In 1990, she conveyed her interest in a portion of that parcel to the Pennsylvania Turnpike

26. *Id.* at 417.
27. *Id.*
28. *Id.*
29. *Id.*
30. *Id.*
31. *Id.* at 419.
32. *See* Ross H. Pifer, *A Greener Shade of Blue?: Technology and the Shale Revolution,* 27 NOTRE DAME J. L. ETHICS, & PUB. POL'Y 131, 135 (2013) (discussing the development of technology that enabled the extraction of shale gas).
33. 204 A.3d 1009 (Pa. Commw. Ct. 2019).
34. *Id.* at 1011.

Commission ("Commission") through a deed in lieu of condemnation.[35] The Commission sought to acquire this land for the construction of the Beaver Valley Expressway.[36] Pursuant to the language in the deed, the conveyance included "all the estate, right, title, interests, property, claim, and demand whatsoever of [McCready]."[37]

In 2012, McCready filed a quiet title action seeking ownership of the mineral estate to the parcel.[38] In support of her claim, she alleged that she had conveyed her property interest solely to avoid the condemnation action and that it was not necessary for the Commission to own the mineral estate for them to construct the highway.[39] Furthermore, she alleged that she did not intend to transfer any interest in excess of that which would have been conveyed through the eminent domain process.[40] Finally, she claimed that the compensation that she received from the Commission for the property interest conveyed did not account for the value of the mineral estate.[41] The Commission's claim for ownership of the mineral estate was based on its argument that the language of the deed was clear in expressing the intention of the parties that the mineral estate had been conveyed.[42]

The court rejected McCready's arguments, finding there were no allegations to support her claims. First, the court found that the deed was clear and there had been no allegation of mutual mistake to justify the introduction of parol evidence.[43] The court also concluded that the Commission did have the authority to obtain a fee simple estate and that the reasonableness of acquiring a fee simple estate was supported by testimony that maintaining control over the subsurface estate benefited the safe operation of the roadway.[44] Finally, the court found no evidence that the purchase price for the property was inadequate.[45] Thus, the Commonwealth Court ruled that the deed had

35. *Id.*
36. *Id.* at 1012.
37. *Id.*
38. *Id.* at 1013.
39. *Id.*
40. *Id.*
41. *Id.*
42. *Id.*
43. *Id.* at 1017.
44. *Id.* at 1018.
45. *Id.* at 1019.

conveyed a fee simple interest in the property and that the Commission was the owner of the mineral estate.[46]

IV. USE OF CONSUMER PROTECTION LAWS IN OIL AND GAS LEASING TRANSACTIONS

During the leasing boom at the onset of shale development in Pennsylvania, many landowners raised complaints about company actions in the procurement of leases.[47] Based upon these complaints, the Pennsylvania Office of the Attorney General ("OAG") sought to utilize Pennsylvania's Unfair Trade Practices and Consumer Protection Law ("UTPCPL")[48] against oil and gas companies.[49] OAG filed suit against Anadarko Petroleum Company ("Anadarko"), Chesapeake Energy Corporation ("Chesapeake"), and related companies under the authority of UTPCPL, alleging "deceptive, misleading, and unfair tactics" as well as antitrust violations in the oil and gas leasing process.[50] OAG alleged that Anadarko and Chesapeake had apportioned the territories in which they each would seek oil and gas leases in an effort to reduce competition.[51] Anadarko and Chesapeake countered these allegations by arguing that UTPCPL only applies to sellers in consumer transactions and that, in the oil and gas leasing context, they were buyers.[52]

The Commonwealth Court began its analysis by reviewing the purpose of UTPCPL as a remedial statute that attempts to equalize the bargaining power between sellers and consumers.[53] Rejecting the argument asserted by Anadarko and Chesapeake, the court found that the alleged conduct came within the definitions of "trade" and "commerce" under UTPCPL.[54] Additionally, the court concluded that

46. *Id.* at 1019.
47. *See* Ross H. Pifer, *Drake Meets Marcellus: A Review of Pennsylvania Case Law upon he Sesquicentennial of the United States Oil and Gas Industry,* 6 TEX. J. OIL, GAS & ENERGY L. 47, 53 (2010-2011) (discussing cases alleging that companies had fraudulently induced landowners into signing oil and gas leases).
48. 73 PA. STAT. §§ 201-1 to 201-9.3 (West 2019).
49. Anadarko Petroleum Corp. v. Pennsylvania, 206 A.3d 51 (Pa. Cmmw. Ct. 2019).
50. *Id.* at 53.
51. *Id.* at 53–54.
52. *Id.* at 54.
53. *See id.* at 55 (quoting Com., by Creamer v. Monumental Props., Inc., 329 A.2d 812, 815-17 (Pa. 1974)).
54. *Id.* at 56.

based upon Pennsylvania precedent, "leases were, in essence, sales."[55] Although Pennsylvania precedent focused on residential leases, the court concluded that business and commercial leases also fell within the ambit of the law.[56] As a result, OAG had the authority to utilize UTPCPL to pursue enforcement against Anadarko and Chesapeake for claims that they acted in a deceptive, misleading, and unfair manner towards landowners in the oil and gas leasing context.[57]

With regard to OAG's use of UTPCPL to pursue antitrust violations, the Commonwealth Court rendered a split verdict. The court held that the statutory language of UTPCPL does not authorize OAG to pursue violations for unlawful joint ventures or for market sharing activities between companies.[58] On the other hand, the court did find that OAG had authority to pursue antitrust violations where companies engage in "unfair methods of competition" or "unfair or deceptive acts or practices."[59]

V. Abandonment of Lease

In *SLT Holdings, LLC, v. Mitch-Well Energy, Inc.*,[60] the Pennsylvania Superior Court invoked the theory of abandonment to rule that an oil and gas lease was no longer valid and that the lessee's removal of oil from tanks on the leased premises constituted conversion. SLT Holdings owned oil and gas rights on two parcels where the leases were held by Mitch-Well Energy.[61] The leases contained fairly typical habendum clauses that included a five-year primary term and a secondary term lasting "as long thereafter as oil or gas or other substances covered hereby are or can be produced in paying quantities."[62] Under the terms of the leases, the lessee had an affirmative obligation to drill a minimum number of wells in accordance with a prescribed drilling schedule.[63] The lease provided that if the lessee failed to comply with this drilling schedule, the lease

55. *Id.*
56. *Id.* at 57.
57. *Id.* at 59.
58. *Id.* at 60–61.
59. *Id.* at 61.
60. __ A.3d __, 2019 WL 3980188 (Pa. Super. 2019).
61. *Id.* at *1.
62. *Id.* at *4.
63. *Id.* at *5.

would terminate. In the event of termination, however, the lessee would retain acreage totaling twenty acres around each well.[64] By lease amendment, the amount of the retained acreage per well was later reduced to five acres.[65]

The lessee did drill wells on the property, but not in compliance with the prescribed drilling schedule.[66] Additionally, from 1996 through 2013, there was no marketable production from the wells on the property.[67] Mitch-Well Energy made no royalty payments nor any other payments to SLT Holdings during this time.[68] Mitch-Well Energy, however, did periodically attend to the wells to ensure that they were in regulatory compliance.[69] In 2013, Mitch-Well Energy entered the property to empty the storage tanks and then sold the oil recovered, which yielded proceeds in the amount of $9,069.53.[70] At this time, SLT Holdings filed suit, seeking a declaration that Mitch-Well Energy had no legal right to be on the premises and that its actions in collecting oil from the storage tanks constituted conversion.[71] Even though there had been no marketable production for a sixteen-year period, the Superior Court relied on the theory of abandonment to rule in favor of SLT Holdings. The court cited *Jacobs v. CNG Transmission Corp.*[72] for the "proposition that an oil and gas lease may be abandoned."[73] Based upon the extended period of inactivity at the wells, the court found that Mitch-Well Energy's actions satisfied the requirements to constitute abandonment.[74] As a result of this abandonment, Mitch-Well Energy had relinquished its legal right to control over the acreage surrounding each well, and its removal of oil from the property did constitute a conversion.[75]

64. *Id.*
65. *Id.*
66. *Id.* at *2.
67. *Id.* at *1.
68. *Id.*
69. *Id.*
70. *Id.* at *8.
71. *Id.* at *2.
72. *Id.* at *8 (citing *Jacobs v. CNG Transmission Corp.*, 332 F.Supp.2d 759, 783-96 (W.D. Pa. 2004)).
73. *Id.* at *7.
74. *Id.* at *7.
75. *Id.* at *8.

SURVEY OF SELECTED 2019 TEXAS OIL AND GAS CASES AND STATUTES

By: William D Farrar[1]

I. INTRODUCTION

Texas courts and the legislature were quite active in 2019 concerning oil and gas issues. Texas courts decided many cases involving everything from deed interpretation to lease repudiation to farmout interpretation. The Texas Supreme Court has granted several petitions for review from the courts of appeal. The legislature enacted or amended statutes concerning so called "royalty leases," the Mineral Interest Pooling Act, and others. The following are summaries of some selected cases and statutes that will be of interest to those involved with Texas oil and gas law.

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A. *Oil and Gas Leases and Provisions*

1. Offset Well Clauses

In *Bell v. Chesapeake Energy Corp.*[2], the San Antonio Court of Appeals used strict contract construction maxims to interpret an "offset clause" in two oil and gas leases to require the lessee to pay compensatory royalties. The relevant lease provisions generally provided that if an offset well were drilled by a third party within 330 feet, or within 467 feet by the if the lessee had an economic interest in it, then the lessee was required to drill a well, release acreage or pay compensatory royalty.[3] The lease defined the compensatory royalty as "an amount equal to the Royalty Share of Gross Proceeds of production from the Adjacent Well . . . ."[4]

The lessee first argued that the offset well provisions were not triggered because the "reasonably prudent operator" standard was implied in the offset clause,[5] meaning even though a well was drilled within the prescribed distance, the well is not a "triggering well" unless it was causing substantial drainage and a reasonably prudent operator would drill a protection well.[6] The court noted that the offset clauses expressly provided that a well drilled within the trigger distance was a "draining well," thus there was no requirement for the lessor to prove substantial drainage, nor was there any language implying a reasonably prudent operator standard.[7] The court held that the lessor "is not required to demonstrate anything other than the existence of an Adjacent Well within the Trigger Distances that has begun production" and thereafter the lessee must either drill, release acreage, or pay the compensatory royalty.[8]

Secondly, the lessee argued that even if the offset clause were triggered, the compensatory royalty should be based on something less

2. *See* No. 04-18-00129-CV, 2019 WL 1139584, at *1 (Tex. App.—San Antonio 2019, pet. filed) (mem. op.) (noting that the case was an accelerated appeal as a representative case of a class action).
3. *Id.*
4. *Id.* at *2.
5. *Id.* at *5.
6. *Id.*
7. *Id.* at *6.
8. *Id.*

than the "Gross Proceeds" from the adjacent well.[9] The court framed the issue as "whether Gross Proceeds are from production from the entirety of a horizontal well, any part of which falls within the Trigger Distances, or production attributable only to those perforations (take points) that are within those Trigger Distances."[10] The court noted that lease offset clause expressly provided that the surface location of a horizontal well was the determinative location of a well rather than the "take points" or location of entry into the productive formation.[11] In seeking to reduce the amount of the "Gross Proceeds" to which the royalty would be paid, the lessee argued that the lease provision did not consider the "realities" of horizontal drilling. However, the court noted that horizontal wells were discussed in the lease and held that the lessee may not now introduce extrinsic evidence of "realities" of horizontal drilling to "alter or contradict the unambiguous [l]ease language."[12]

The lessee's argument was essentially "that calculating Compensatory Royalty according to the plain language of the Leases is a bad deal."[13] The court disagreed, noting that the lessee was a sophisticated industry player, represented by experienced counsel, and fully expected horizontal wells would be drilled. Accordingly, the express language in the leases controlled requiring that the lessee pay the compensatory royalty on the gross production from the adjacent wells.[14]

2. Royalty Payments and Post-Production Cost Deductions

In *Bluestone Nat. Res. II, LLC v. Randle*, the Fort Worth Court of Appeals construed royalty payment clauses in an oil and gas lease to uphold the trial court's determination that the lessee could not deduct post-production costs from the lessor's royalty.[15] The lease in

9. *Id.* at *5
10. *Id. at* *12.
11. *Id.* at *13 (The relevant lease language stated ". . . in the case of a Horizontal Well[,] distance will be measured from the surface location or the subsurface path of a horizontal drainbore, from its point of entry into the productive horizon to its terminus, whichever is closer").
12. *Id.* at *14.
13. *Id.* at *15.
14. *Id.*
15. No. 02-18-00271-CV, 2019 WL 1716415, at *1 (Tex. App.—Fort Worth 2019, pet. filed) (mem. op.).

question was described by lessee's counsel as a "Frankenstein's Monster" with its parts "cobbled together from the parts bin of oil and gas lease provisions."[16] The lease had a printed portion with an Exhibit A attached as an addenda. The printed portion of the lease contained a royalty clause that stated lessor's royalty would be based on:

> the market value at the well of one-eighth of the gas so sold or used, provided that on gas sold by Lessee the market value shall not exceed the amount received by Lessee for such gas computed at the mouth of the well, and on gas sold at the well the royalty shall be one-eighth of the amount realized by Lessee from such sale . . . .[17]

Exhibit A provided that "it is understood and agreed by all the parties that the language on this Exhibit 'A' supersedes any provisions to the contrary in the printed lease hereof."[18] Exhibit A also included the following provision relating to royalty payments:

> *LESSEE AGREES THAT all royalties accruing under this Lease (including those paid in kind) shall be without deduction, directly or indirectly, for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and otherwise making the oil, gas[,] and other products hereunder ready for sale or use. Lessee agrees to compute and pay royalties on the gross value received, including any reimbursements for severance taxes and production related costs.*[19]

The court noted that typically there are three issues to consider: (1) the fraction of royalty such as 1/4th or 1/8th; (2) the method of

16. *Id.* (In this author's experience, this is fairly typical—leases many times are assembled with a printed form and various addenda attached modifying, or adding to, the printed form).
17. *Id.* at *2.
18. *Id.*
19. *Id.*

valuation, such as "market value" or "proceeds"; and (3) the geographic location at which the value or proceeds is determined, such as "at the wellhead" or "at the point of sale." Specifically, this case involves the last two.[20] "Proceeds" or "amount realized" is the amount the lessee actually receives from a sale, while "market value" requires payment of market price in the vicinity of the wellsite irrespective of actual sales price.[21] Market value can be determined either through the "comparable sales method" or the "net-back method."[22] The comparable sales method uses other sales that are "comparable in time, quality, quantity, and availability of marketing outlets."[23] The "net-back" method, "which determines the prevailing market price at a given point and backs out the necessary, reasonable costs between that point and the wellhead."[24]

The court found that although the preprinted lease form called for valuation based on "market value at the well," which necessarily allowed post-production cost deductions, Exhibit A to the lease provided for valuation based on proceeds received by lessee.[25] The court pointed out that although identical proceeds language on Exhibit A had been held to be "mere surplusage" in *Heritage Resources v. Nationsbank*,[26] However, the court enforced the proceeds valuation based on the Exhibit A language stating that Exhibit A controlled over the preprinted lease form in the event of any conflict. Accordingly, the lessee could not deduct post-production costs from the lessor's royalty.

3. Lease Repudiation by Lessor

In *Lona Hills Ranch, LLC v. Creative Oil and Gas Operating, LLC*,[27] the Austin Court of Appeals determined that the Texas Citizens

20. *Id.* at *4. *See also* Byron C. Keeling, *In the New Era of Oil and Gas Royalty Accounting: Drafting a Royalty Clause That Actually Says What the Parties Intend It to Mean*, 69 Baylor L. Rev. 516, 520–528 (2017).
21. *Bluestone Nat. Res.*, 2019 WL 1716415, at *8–9.
22. *Id.* at *5.
23. *Id.* (quoting Heritage Res. v. Nations Bank, 939 S.W.2d 118, 122 (Tex. 1996)).
24. *Id.* (quoting *Heritage Res.*, 939 S.W.2d at 130).
25. *Id.* at *16.
26. *Id.*
27. 549 S.W.3d 839 (Tex. App.—Austin 2019) (pet. granted).

Participation Act ("TCPA")[28] did not preclude the lessee from pursuing a breach of contract claim against the lessor for failure to comply with a "notice before litigation" clause in the lease. The lessor first filed a complaint at the Texas Railroad Commission based on lack of production, challenging the operator's "good faith claim" of the right to continue to operate the lease.[29] The Railroad Commission dismissed the complaint, finding the operator had shown a good faith claim to continue to operate the well.[30] The lessor did not appeal this decision but instead initiated litigation in the district court against the operator for trespass to try title and trespass based on allegations of lack of production.[31]

The operator filed an answer and noted it was a contract operator only and owned no interest in the well or lease and filed counterclaims alleging the lessor had interfered with the sale of oil produced, wrongfully filed the Railroad Commission complaint, and breached the lease by failing to comply with the lease's pre-suit notice requirements, which would have given the lessee an opportunity to cure.[32] The lessee intervened in the suit and filed its own counterclaim against the lessor for breach of contract.[33] The lessor filed a motion to dismiss both counterclaims under the TCPA. The trial court never ruled on lessor's motion, thus it was denied by operation of law and addressed for the first time on appeal.[34]

The appellate court found that the lessor had met its *prima facie* standard for dismissal under the TCPA, but then analyzed the operator's response to determine if it could prove each element of its breach of contract claims.[35] The court determined that the trial court should have dismissed the operator's counterclaim because, as a non-party to the lease allegedly breached, the operator could never prove a breach of contract.[36] With respect to the lessee's counterclaim, the court found that the lessor had failed to establish grounds for dismissal because the notice before litigation clause in the lease was a

28. TEX. CIV. PRAC. & REM. CODE § 27.001 (2018).
29. *Lona Hills Ranch*, 549 S.W.3d at 842.
30. *Id.*
31. *Id.*
32. *Id.* at 843.
33. *Id.*
34. *Id.*
35. *Id.* at 847.
36. *Id.* at 848.

contractual limitation on the lessor's right to petition under the TCPA.[37]

B. *Mineral Ownership*

1. Executive Rights and Duties to Non-Executives

In *Tex. Outfitters, Ltd. v. Nicholson*,[38] the Texas Supreme Court held that an executive mineral owner breached its duty of utmost good faith in failing to execute a mineral lease. Texas Outfitters, the owner of the surface estate, and a minority mineral interest also held the executive rights to 50% of the mineral estate.[39] The other 50% of the mineral estate was owned by others.[40] A lessee leased the 50% mineral interest owned by others and offered the same lease terms to Texas Outfitters for the remaining 50%.

Texas Outfitters declined to lease, believing that lease bonus amounts might go even higher and to protect his hunting business, despite the non-executive owner's desire that the lease be executed.[41] Thereafter, the non-executives requested a meeting with Texas Outfitters and proposed a resolution whereby they would purchase the executive rights to their mineral interest, forgive part of a seller-financed note that Texas Outfitters owed them, and they would lease all their minerals.[42] However, no deal was reached because the parties were unable to agree on the specific terms of surface restrictions. The non-executives filed suit against the executive for breaching the duty of utmost good faith and fair dealing for failing to enter into a lease.[43]

At a bench trial, judgment was entered against the executive owner for $867,654.32, the amount of the bonus the non-executives would have received.[44] The court of appeals affirmed, holding that "the evidence supports a finding that Texas Outfitters refused to execute the . . . lease based on its arbitrary and self-motivated refusal to permit *any* lease for the purpose of protecting its use of the surface

37. *Id.*
38. 572 S.W.3d 647 (Tex. 2019).
39. *Id.* at 649.
40. *Id.*
41. *Id.* at 650.
42. *Id.*
43. *Id.*
44. *Id.*

and to exact a benefit from the [non-executive] [e.g., the note reduction and deed restrictions] to their detriment."[45]

The Texas Supreme Court first reiterated the law regarding the executive's duty to the non-executives:

1. [T]he duty does not require an executive to subjugate his interests to those of the non-executive; rather, the executive must 'acquire for the non-executive every benefit that he exacts for himself.[46]
2. An executive is not 'wholly shielded from liability for inaction, i.e., failure to lease, noting that if an executive's refusal to lease upon request 'is arbitrary or motivated by self-interest to the non-executive's detriment, the executive may have breached his duty.'[47]

Applying these principles, the Court stated they "cannot be applied in a vacuum and must account for the fact that executives and non-executives often 'do not share in all the same

economic benefits that might be derived from a mineral lease,'"[48] and "evaluating compliance with the executive duty is rarely straightforward and is heavily dependent on the facts and circumstances."[49] The Court then noted that the trial court had made numerous findings of fact and conclusions of law and its review on appeal was to determine if "more than a mere scintilla" of evidence exists to uphold the trial court's judgment and the court of appeals affirmation in favor of the non-executive.[50]

In affirming the judgments below, the Court noted that the executive owner knew that 50% of the minerals had already been leased to a lessee and "gambling" that a higher offer would come in from a different lessee was highly unlikely and gambled

45. *Id.* at 651–52.
46. *Id.* at 652 (quoting KCM Fin., LLC v. Bradshaw, 457 S.W.3d 70, 74 (Tex. 2015)).
47. *Id.* at 652 (quoting Lesley v. Veterans Land Bd., 352 S.W.3d 479, 491 (Tex. 2011)).
48. *Id.* at 652 (quoting *KCM Fin.*, 457 S.W.3d at 82).
49. *Id.* at 653.
50. *Id.* at 653.

disproportionality with the non-executive's interest as compared to the executive's, and solely to benefit the executive's surface estate.[51]

2. Co-tenancy of the Mineral Estate

In *Cimarex Energy Co, v. Anadarko Pet. Co.*, the El Paso Court of Appeals held that one co-tenant's production activities on land would not perpetuate another co-tenant's oil and lease on an undivided interest in the same land.[52] Cimarex owned a lease with a five-year primary term on an undivided 1/6th mineral interest in 440 acres.[53] Anadarko owned leases on the other 5/6ths mineral interest. Anadarko also had the lease on an adjacent 200 acres.[54] Anadarko drilled two wells on the 440 acres, both of which paid out and produced in paying quantities thereafter.[55] Cimarex requested to participate in the costs of the development of the two wells, and Anadarko refused.[56] Anadarko then applied for a permit to drill a well on the 200-acre lease.[57] The well's location was too close to the 440 acres for a regular permit, thus Anadarko filed for a Rule 37 exception permit and notified Cimarex of the application.[58] Cimarex failed to object to the permit application, and the permit was granted. Anadarko thereafter drilled and completed a successful well.[59] The lessors of the Cimarex lease then executed top leases covering the 1/6th interest to a third party that were then acquired by Anadarko.[60] Thus, Anadarko held leases on 5/6th mineral interest and top leases on 1/6th mineral interest.

After Anadarko failed to provide information on the wells or an accounting, Cimarex filed suit seeking an accounting for its 1/6th co-tenant share of the net profits for the wells located on the 440 acres. Additionally, Cimarex attempted to force pool some of the land covered by its lease at the Texas Railroad Commission into the well located on the adjacent 200 acres using the Mineral Interest Pooling

51. *Id.* at 657.
52. 574 S.W.3d 73 (Tex. App.—El Paso 2019).
53. *Id.* at 80–81.
54. *Id.* at 81.
55. *Id.*
56. *Id.* at 82.
57. *Id.* at 81–82.
58. *Id.* at 82.
59. *Id.*
60. *Id.*

Act.[61] Cimarex and Anadarko thereafter reached a settlement in which Anadarko agreed to pay Cimarex 1/6th of the net profits for the two wells located on the 440 acres and to provide income and expense data and payments of net profits on an ongoing basis.[62] Cimarex paid its lessors their royalty on the production as well.[63] Anadarko performed under the terms of the settlement agreement, but when the five-year primary term of the Cimarex lease ended, Anadarko stopped performing, claiming Cimarex's leasehold interested had terminated because Cimarex had not established production on its lease to perpetuate the lease into the secondary term.[64]

Cimarex then filed suit against Anadarko.[65] Both parties filed motions for summary judgment.[66] Anadarko defended its position and the superiority of its top leases on the basis that the Cimarex lease required Cimarex to establish production and that the activities of Anadarko, Cimarex's co-tenant, were not sufficient to do so.[67] Cimarex argued that the lease only required production "on the lands covered by the lease." Their reasoning was that since Anadarko had established production on the same lands the lease was perpetuated and because Cimarex had paid royalties to its lessors, both they, and Anadarko as the top lessee standing in the same shoes, were equitably estopped from repudiating the Cimarex lease.[68] The trial court disagreed, finding that the Cimarex lease had expired at the end of its five-year primary term and that the doctrine of equitable estoppel was not applicable.[69]

On appeal, the parties reasserted the same arguments as below. The court of appeals relied heavily on *Hughes v. Cantwell*,[70] where the court held that a lessee of a lease covering a fractional co-tenant interest in minerals is required to undertake drilling activities and may not rely on the activities of its co-tenant.[71] The court explained as its

61. *Id.* at 83.
62. *Id.* at 83–84.
63. *Id.* at 84.
64. *Id.*
65. *Id.*
66. *Id.*
67. *Id.*
68. *Id.* at 65.
69. *Id.*
70. 540 S.W.2d 742 (Tex. Civ. App.—El Paso 1976) (writ ref'd. n.r.e.).
71. *Id.* at 90–93; Cimarex Energy Co. v. Andarko Petroleum, 574 S.W.3d 73 (Tex. App.—El Paso 2019).

reasoning in *Hughes* that the lease stated in several places that the "lessee" was authorized or obligated to do certain things, such as pay delay rentals, pool the lease, pay royalties, thus the option to either drill a well or pay delay rentals was an option for Hughes. Therefore, the fact that a co-tenant had commenced drilling operations did not keep the Hughes lease from terminating when Hughes elected not to pay delay rentals.[72] The court further explained that in order to rely on a co-tenant's activities, one must participate, actually or constructively, in paying their share of the drilling costs.[73]

Following their opinion in *Hughes*, the court noted that the Cimarex lease likewise authorized or required the "lessee" to explore for and produce oil and gas; pay royalties; undertake reworking or new drilling operations; pool the lease; designate pooled units; assign the lease; use oil, gas and water from the land for operations; and finally, to remove its equipment after lease termination.[74] Thus, reasoned the court, it is implied "that the lessors intended for Cimarex to be the one to cause production on the property in order to extend the lease into the secondary term."[75]

Cimarex next argued that it had paid royalties to the lessors based on Anadarko's production, and "it would be inherently inconsistent to interpret the lease to require it to pay royalties on Anadarko's production during the primary term, while not allowing Cimarex to rely on Anadarko's production to keep the lease alive into the secondary term."[76] However, the court disagreed, stating that it was entirely possible that the lessors could have intended that royalties be paid on a co-tenants production during the primary term, but to require its lessee, Cimarex, to establish its own production to perpetuate the lease into the secondary term.[77] Cimarex next argued that it would be bad public policy to hold that one co-tenant's activities would not perpetuate another co-tenant's lease and would discourage the leasing of minority mineral interests given that it is typically uneconomic for a minority co-tenant to undertake the financial risk of drilling a well.[78] However, the court disagreed, observing that:

72. *Cimarex Energy Co.*, 574 S.W.3d at 91.
73. *Id.*
74. *Id.* at 92.
75. *Id.*
76. *Id.* at 94.
77. *Id*. at 94–95.
78. *Id.* at 95.

> *Cimarex was aware of the laws relating to co-tenancy when it entered into the lease agreeing to take a minority interest… [and] Cimarex knowingly took the risk that other tenants on the land might refuse to agree to a joint operating agreement, and that it might be forced to, at some point, commence production on its own, as contemplated by the terms of the lease.*[79]

Cimarex next argued that its Settlement Agreement with Anadarko was a joint operating agreement, meaning Cimarex and Anadarko were jointly developing the lands, and the Cimarex lease was perpetuated by the efforts of both Cimarex and Anadarko.[80] Anadarko countered that the Settlement Agreement did nothing more than recognize Cimarex was entitled to its non-developing cotenant share of the net profits.[81] The court agreed with Anadarko, pointing out that while no particular form of agreement is required to be a joint operating agreement, the hallmarks of an operating agreement are to share revenues, share expenses, allocate liabilities, designate an operator, and define the geographic area to which it applies.[82] These attributes were juxtaposed to the Settlement Agreement, which merely recognized Cimarex as a 1/6th co-tenant entitled to a 1/6th co-tenant's share of net income. The Settlement Agreement omitted any reference to joint development, responsibility of costs and liabilities, and indeed referenced Cimarex as a "non-participating cotenant," as opposed to a "non-operator."[83]

Finally, Cimarex argued that its lessors, and Anadarko by virtue of the top lease, were equitably estopped from claiming Cimarex's lease terminated because the lessors accepted royalties on Anadarko's production during the primary term. The court dispensed with this argument stating: "we have interpreted the habendum clause in the Cimarex lease to require Cimarex to pay royalties on *any* production on the land during the "paid-up" primary term of the lease, while requiring Cimarex to cause actual production on the subject

79. *Id.*
80. *Id.* at 96.
81. *Id.*
82. *Id.* at 97.
83. *Id.*

property to extend the lease into the secondary term."[84] Finally, the court upheld the trial court's award of attorney's fees to Anadarko as a "prevailing party" under the attorney's fee provision of the Settlement Agreement.[85] The holding in the Cimarex case is a warning that when taking an oil and gas lease on a fractional interest, the lessee should include language in the lease that would recognize a co-tenant's operations or production for purposes of perpetuating the lease. It is the author's observation that this case is contrary to the assumption that a mineral lessee stands in the shoes of its lessor with respect to co-tenancy law, while honoring the general proposition that Texas jurisprudence over the years has tended to support those who are spending money, thereby incurring risk, to bring oil and gas to the surface, as opposed to those who passively rely on other's efforts. It will be interesting to see the result if petition is granted on this case.

3. Consent to Assign Clauses

In *Barrow-Shaver Res. Co. v. Carizzo Oil & Gas, Inc.*,[86] the Texas Supreme Court found that Carrizo had an unqualified right to refuse to consent to Barrow-Shaver's transfer of rights under a farmout agreement. Carizzo held oil and gas leases on 22,000 acres that were about to expire.[87] Prior to the farmout agreement being executed, the parties negotiated various drafts of the agreement, including the wording of the consent to assign clause that provided that consent could not be withheld unreasonably. Testimony at trial stated that Carizzo refused to qualify the language in the agreement but had verbally promised it would consent in the event Barrow-Shaver ever wanted to assign its rights.[88] The parties ultimately entered into the farmout agreement that contained the following clause:

> The rights provided to [Barrow-Shaver] under this Letter Agreement may not be assigned, subleased or

84. *Id.* at 100.
85. *Id.* at 101,
86. Barrow-Shaver Res. Co. v. Carizzo Oil & Gas, Inc., No. 17-0332, 2019 WL 2668317 (Tex. June 28, 2019).
87. *Id.* at *2.
88. *Id*. at *2–3.

> otherwise transferred in whole or in part, without the express written consent of Carrizo.[89]

Barrow-Shaver spent over $22,000,000 drilling an unsuccessful well on the lands covered by the farmout agreement.[90] Thereafter, a third party offered to purchase Barrow-Shaver's interest in the farmout agreement for approximately $27,000,000.[91] Barrow-Shaver requested that Carizzo consent to the assignment of the farmout agreement to the third party.[92] Carizzo refused to consent, instead offering to sell its interest in the leases to Barrow-Shaver for $5,000,000.[93] Barrow-Shaver refused to purchase the farmout agreement, and the underlying leases expired worthless.[94]

Barrow-Shaver sued Carizzo for breach of contract, fraud, and tortious interference with a contract.[95] At trial, both parties agreed that the consent to assign clause was unambiguous, but Barrow-Shaver also argued that the contract was silent on the bases that Carizzo could refuse to consent.[96] The trial court refused to admit prior drafts of the farmout agreement in which Carizzo had deleted the phrase "which consent shall not be unreasonably withheld."[97] Both parties proffered expert testimony on industry custom and usage, with respect to the standards governing when consent to assign can be withheld. Barrow-Shaver's expert opined that a standard of good faith governed, and that the request for $5,000,000 was a breach of the farmout agreement. Carizzo's expert opined that the clause was a "hard consent," and Carizzo could refuse to consent for any reason.[98] At trial, the jury found that Carizzo had breached the farmout agreement and awarded almost $28,000,000 damages and attorney's fees to Barrow-Shaver.[99] Carizzo appealed, and the 12th Court of Appeals reversed, finding that the trial court erred in not allowing the prior drafts of the farmout agreement into evidence to show that Carizzo had bargained for "hard

89. *Id*. at *1–2.
90. *Id*. at *2.
91. *Id.*
92. *Id.*
93. *Id.*
94. *Id.*
95. *Id.*
96. *Id.* at *2–3.
97. *Id.* at *3.
98. *Id.*
99. *Id.*

consent."[100] The appellate court also held that the existence of a written contract vitiated any cause of action based on fraud, and since Carizzo had the right to withhold consent, there could be no tortious interference with contract.[101] Barrow-Shaver petitioned to the Texas Supreme Court, which was granted.

The Texas Supreme Court ultimately held that the farmout agreement was unambiguous, and neither the prior drafts of the agreement, nor industry custom and usage, were admissible. In reaching this decision, the Court found that there was no breach of contract in refusing to consent because the plain wording of the agreement gave Carizzo the right to refuse to consent for any reason. The court held:

> The consent-to-assign provision plainly states that Barrow-Shaver cannot assign its rights unless it obtains Carrizo's consent, which must be express and in writing. In other words, Carrizo has a right to consent to a proposed assignment, or not. The plain language of the provision imposes no obligation on Carrizo—it does not require Carrizo to consent when certain conditions are satisfied, require Carrizo to provide a reason for withholding consent, or subject Carrizo to any particular standard for withholding consent.[102]

The majority found that there were no material terms in the consent to assign clause. Therefore, there was no need to allow extrinsic evidence to explain "immaterial terms."[103] The Court also found that industry custom and usage were not admissible when the clause was otherwise unambiguous.[104]

In response to Barrow-Shaver's argument that a duty of good faith is imposed on Carizzo in its decision whether to consent or not, the Court held "this Court has been clear that absent a special relationship, parties to a contract have no duty to act in good faith."[105]

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100. *Id.*
101. *Id.*
102. *Id.* at *6.
103. *Id.* at *7.
104. *Id.* at *26–37.
105. *Id.* at *41.

The court pointed out that in its view, a farmout agreement between sophisticated parties is not similar to the relationship between insurers and insureds with unequal bargaining power.[106] Finally, the Court found no fraud cause of action was available to Barrow-Shaver because the direct language of the farmout agreement contradicted the alleged oral promise by Carizzo to consent if requested.[107]

The dissenting opinion noted that industry custom and usage evidence are routinely admitted to explain an otherwise unambiguous contract, citing the classic example of a "baker's dozen" not being a dozen but thirteen.[108] Explaining further, the dissent noted "this Court has noted that a 'thousand' rabbits may mean 1,200; a 'day' may mean 10 hours; and '4,000' shingles may mean 4500,"[109] and the majority holding "that trade custom and usage has no applicability to terms that are 'not susceptible to more than one [meaning[] and [are] not industry or vocation specific" is manifestly wrong."[110]

It should be noted that a petition for rehearing has been filed in this case. The holding in this case has potential impact beyond a farmout agreement, which was at issue in this case. Many exploration agreements, oil and gas leases, pipeline easements, and others have consent to assign clauses. It is the author's experience that if a party wishes to withhold consent with unfettered discretion, the consent to assign clause should add a qualifier such as "may withhold consent in its sole discretion" or "may withhold consent for any reason," and absent such qualifier, there should be a commercially valid reason for refusing to consent. The take-a-way from this case is that the Texas Supreme Court has adopted a very non-industry specific reading of contracts—if the contract words appear in a dictionary, then one need not consult industry custom and trade usage.

II. Statutory Changes

A. *"Royalty Leases" and Addition of Section 5.152 of the Texas Property Code*

106. *Id.* at *41–42.
107. *Id.* at *65–66.
108. *Id.* at *84.
109. *Id.*
110. *Id.* at *84–85.

In recent years, there have been an increasing number of disputes arising over purported "royalty leases," whereby a buyer purports to "lease" the royalty interest a party owns in lands that are already leased or under production. The buyers of the purported "leases" argue that the fact that the instrument is entitled or written as a lease does not prevent its effectiveness to convey a term royalty interest or a defeasible fee. Some of the bases of the dispute can be found in the class action suit entitled *Danna Sue Bridges et al v. Ridge Natural Resources*.[111] The gist of the complaint is that mineral/royalty owners receive what appears at first glance to be a typical oil, gas, and mineral lease, and they assume it is on lands not currently leased, or is a "top lease." However, the buyer claims that the "lease" is actually a conveyance, usually of the grantor's share of existing royalty in existing production from lands already under lease, rather than a lease on unproductive land that would require exploration efforts to perpetuate the lease. Some of the "royalty leases" include arbitration clauses that require any disputes to be resolved through binding arbitration.[112]

The Texas legislature added section 5.152 of the Texas Property Code, effective September 1, 2019, to require additional notices and requirements when attempting to acquire permanently, or for a term, the mineral interest or royalty interest a lessor has in an existing oil and gas lease.[113] Among the requirements are that a notice in 14 point typeface stating: "THIS IS NOT AN OIL AND GAS LEASE. YOU ARE SELLING ALL OR A PORTION OF YOUR MINERAL OR ROYALTY INTERESTS IN (DESCRIPTION OF PROPERTY BEING CONVEYED)" must appear on each page of the lease and immediately above the signature line.[114] If the notices are not included, the instrument is void, as opposed to voidable.[115]

The new statute provides for the recovery of all oil and gas revenues paid to the purported lessee, costs, and attorney's fees.[116] Finally, the statute is cumulative with other remedies, thus a

111. Class Action Complaint, Danna Sue Bridges et al v. Ridge Natural Resources, No. 7:18-cv-00134-DC, 2018 WL 10072188 (W.D. Tex. Aug. 3, 2018).
112. Ridge Nat. Res. v. Double Eagle Royalty, 564 S.W.3d 105, 116 (Tex. App.—El Paso 2018, no pet.).
113. TEX. PROP. CODE § 5.152 (2019).
114. § 5.152(c).
115. § 5.152(d).
116. § 5.152(e).

complainant could, for example, also bring claims for common law fraud, statutory fraud, and others.[117]

B. *Mineral Interest Pooling Act Amendments*

The Texas legislature, effective September 1, 2019, amended the Mineral Interest Pooling Act to provide that a unit formed under the Act will dissolve two years after formation if no drilling occurs in the unit or surface location for the unit.[118] The prior version of the statute required dissolution at the end of one year.

C. *Ownership of Fluid Oil & Gas Waste*

The Texas legislature, effective September 1, 2019, amended Texas Natural Resources Code section 122.002 to provide that a person or entity that acquires fluid oil and gas waste for the purposes of treating it for further beneficial use, owns the fluid waste, absent "an oil or gas lease, a surface use agreement, a contract, a bill of sale, or another legally binding document to the contrary."[119] Presumably, the purpose of this amendment is to resolve a dispute between a surface owner, mineral owner, and lessee over who has the right to the fluid waste, which could be quite valuable given the scarcity of water in some areas.

117. § 5.152(f).
118. TEX. NAT. RES. CODE § 102.082 (2019).
119. TEX. NAT. RES. CODE § 122.002 (2019).

UTAH

Mark Burghardt & Gage Hart Zobell [1]

I. INTRODUCTION

Oil and gas production continues to be an important sector of Utah's economy. Following a 25% loss in production between 2014 and 2015, Utah's production continues to slowly rebound.[2] Crude oil production in 2019 appears to be slightly ahead of 2018 production.[3] Monthly production averages slightly over three million barrels, placing Utah among the top ten states in crude oil production.[4] Along

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2. *Utah Field Production of Crude Oil*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUT1&f=M [https://perma.cc/8F33-7ULW] (last visited Oct. 10, 2019).

3. *Id.*

4. *Petroleum & Other Liquids: Crude Oil Production,* U.S. ENERGY INFO. ADMIN., https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm [https://perma.cc/C39L-4WDW] (last visited Oct. 10, 2019).

with the continuing increase in production, the state's legal framework governing oil and gas continues to develop.

This Article examines recent changes in Utah statutes and regulations along with new case law developments involving the oil and gas industry. In particular, this Article discusses a recent federal bankruptcy decision involving midstream agreements,[5] the revision to a Utah statute that now requires mandatory reporting of unclaimed mineral interests,[6] and recent revisions to Utah's oil and gas regulations.[7]

II. CASE LAW

A. *Federal Cases*

1. Monarch Midstream, LLC v. Badlands Production Company, et al

The United States Bankruptcy Court for the District of Colorado, construing Utah law, recently held that a Gas Gathering and Processing Agreement ("GGPA") and a Salt Water Disposal Agreement ("SWDA") were covenants running with the land that could not be extinguished through a bankruptcy sale.[8] In so holding, the bankruptcy court became the first court to distinguish the recent *Sabine* decision, which held that midstream agreements were not covenants running with the land and could be discharged in bankruptcy.[9]

Initially, in 2010, Monarch Midstream, LLC ("Monarch") acquired portions of midstream infrastructure that serviced the Riverbend oil and gas assets ("Riverbend Assets") held by Badlands Energy, Inc., formerly known as Gasco Energy, Inc. ("Badlands"). Following the purchase, Monarch and Badlands entered into a GGPA and SWDA, wherein Badlands dedicated and committed all "*[g]as reserves in and under*" and all "gas owned by production and produced from" the leases held by Badlands within an area of mutual interest

5. *In re Badlands Energy, Inc.*, 608 B.R. 854 (Bankr. D. Colo. 2019).
6. UTAH CODE ANN. § 75-2-105 (West 2019).
7. UTAH ADMIN. CODE R. 850-21 *et. seq.*
8. *In re Badlands Energy, Inc.*, 608 B.R. 854.
9. *In re* Sabine Oil & Gas Corp., 547 B.R. 66 (Bankr. S.D.N.Y. 2016); affirmed in *In* re Sabine Oil & Gas Corp., 567 B.R. 869 (S.D.N.Y. 2017) and *In re* Sabine Oil & Gas Corp., 734 Fed.Appx. 64 (2d Cir. 2018) (finding that a midstream agreement did not constitute a covenant running with the land and the burden could, therefore, be discharged through a bankruptcy sale).

("AMI").[10] Under the GGPA, Badlands was required to deliver quarterly a minimum volume of gas or pay Monarch a shortfall as liquidated damages. Under the SWDA, Badland committed to dispose of all its operational water within the AMI with Monarch's disposal facilities. Both the GGPA and SWDA expressly stated that they were covenants running with the land.

In 2017, Badlands Energy, Inc. and related entities filed for chapter 11 bankruptcy. The bankruptcy court ordered a "free and clear" sale authorizing Badlands to auction a portion of the Riverbend Assets to Wapiti Utah, LLC ("Wapiti"). As part of the sale, Badlands rejected the GGPA and SWDA, which were not assumed or assigned to Wapiti. Monarch objected to the sale on grounds that the agreements could not be rejected, since they were covenants running with the land.

The bankruptcy court determined that the Colorado choice of law provisions in the GGPA and SWDA were not applicable, ruling that Utah law governed because property interests are created and defined by the law of the state where the property is located.[11] The court ruled that under Utah law the GGPA and SWDA were covenants running with the land. The court applied a four-element test: (1) the covenant must "touch and concern" the land; (2) there must be privity of estate; (3) the covenant must be in writing; and (4) the parties must intend for the covenant to run with the land.[12] Neither party disputed that the covenant was in writing, so the court focused on the other three elements.

In its decision, the court relied heavily on the Utah case of *Flying Diamond Oil Corp. v. Newton Sheep Company*.[13] The "touch and concern" element typically requires a showing of some physical effect to the land. However, the court, following *Flying Diamond*, held that the "touch and concern" element is met when a covenant either enhances or diminishes the value of the land.[14] The bankruptcy court distinguished *Sabine* by highlighting that the gas dedication in *Sabine* only covered the gas and condensate produced and saved from the wells. Under both Texas and Utah law, extracted minerals are personal property, not real property, and therefore the "touch and

10. *In re Badlands Energy, Inc.*, 608 B.R. at 869.
11. *Id.* at 867.
12. *Id.*; *see also* Flying Diamond Oil Corp. v. Newton Sheep Co., 776 P.2d 618, 624 (Utah 1989) (*hereinafter* "Flying Diamond").
13. *See Flying Diamond*, 776 P.2d 618.
14. *In re Badlands Energy, Inc.*, 608 B.R. at 868.

concern" element was not satisfied. The GGPA in question, however, dedicated the interest in all gas reserves "*in and under*" those leases held in the AMI.[15] The court reasoned that these dedicated reserves could be broadly defined to include the unproduced oil and gas, which is real property under Utah law.[16] The court determined that a dedication of the unproduced oil and gas, which were real property interests themselves, diminished the value of the land. Therefore, the GGPA and SWDA covenants did in fact "touch and concern" the land.

To determine the "intent" element, the court once again followed *Flying Diamond* and held that an express statement that the covenant was intended to run with the land was dispositive of intent.[17] Both the GGPA and the SWDA contained multiple statements expressly stating the intention to create a covenant running with the land. On this basis, the court held the "intent" element was easily satisfied.

Turning to the requirement of "privity," the court considered the three types of privity typically required: (1) vertical, (2) horizontal, and (3) mutual. Under Utah law, vertical privity is found when a person claiming the benefit, or subject to the burden, is the successor to the original person so benefited or burdened.[18] The court determined vertical privity existed, as Wapiti was the successor to Badland, the original party to the GGPA and SWDA.[19] Horizontal privity exists under Utah law when "the original covenanting parties create a covenant in connection with a simultaneous conveyance of the estate."[20] The bankruptcy court determined simultaneous conveyances did occur. First, the GGPA's dedication burdening the gas reserves constituted conveyance of the mineral estate. Additionally, the grant of easements in both the SWDA and GGPA were held to be conveyances of real property interests, thereby creating horizontal privity.[21] Finally, unlike other jurisdictions, Utah has never adopted the requirement to show mutual privity. Thus, the court concluded that the simultaneous interests of the Badlands and Monarch in the gas reserves within the AMI satisfied a showing of mutual privity to the extent required under Utah law.[22] Ultimately, the

15. *Id.* at 869.
16. *Id.*
17. *Id.* at 870.
18. *Flying Diamond*, 776 P.2d at 628.
19. *In re Badlands Energy, Inc.*, 608 B.R. at 871.
20. *Flying Diamond*, 776 P.2d at 628.
21. *In re Badlands Energy, Inc.*, 608 B.R. at 874.
22. *Id.* at 873.

court determined that since the SWDA and GGPA were covenants running with the land, they are "part of the bundle of sticks that Wapiti acquired when it purchased the Riverbend Assets, and they are not subject to elimination utilizing [the bankruptcy code]."[23] An appeal of the decision is expected.

Additional litigation in Utah and across the United States is expected to help delineate the *Sabine* decision and determine when midstream agreements create real property interests that cannot be rejected in bankruptcy. Until that case law develops, the *Monarch* decision provides authority for the proposition that a midstream agreement creates a real property interest that survives a "free and clear" bankruptcy sale, so long as it burdens hydrocarbons in the ground.

III. STATUTES / REGULATIONS

A. *2019 S.B. 78: Utah Code Ann. § 75-2-105*

On March 25, 2019, Governor Herbert signed Senate Bill 78 into law. This bill amended Utah's law governing the escheat of property to the state when a decedent's heirs cannot be located.[24] The new law amends Utah Code Ann. § 75-2-105 by identifying the Utah State School and Institutional Trust Lands Administration ("SITLA") as the state agency responsible for administering the unclaimed mineral interests, clarifying the state's initiation of a quiet title action and creating an affirmative duty to report information regarding intestate succession to the state.[25]

Under the old statute, no state agency was specifically tasked with the administration of escheated mineral interests. However, as the interest escheated "for the benefit of the permanent state school fund," the escheated interests were usually administered by SITLA. The amendment codifies this long standing practice granting SITLA explicit administration authority over escheated mineral interests.[26] In addition, the amendment also grants SITLA the authority to file a quiet title action in district court in order to confirm the state's claim to unclaimed mineral interests.[27] Finally, the amendment creates an

23. *Id.* at 874.
24. UTAH CODE ANN. § 75-2-105(2) (West 2019)..
25. *See* S.B. 78, 63d Leg., Gen. Sess. (Utah 2019) (eff. May 14, 2019).
26. UTAH CODE ANN. § 75-2-105(3) (West 2019).
27. UTAH CODE ANN. § 75-2-105(4) (West 2019).

affirmative duty for operators, owners, and payors to submit information concerning "the identity of the decedent, the results of a good faith search for heirs . . ., the property interest from which the minerals or mineral proceeds derive, and any potential heir" to SITLA within 180 days of acquiring the information.[28]

At this point, the new statute appears to provide a regulatory framework for dealing with escheated interests. Although the revised statute creates an affirmative duty to report, it does not provide for an enforcement mechanism. Absent any penalty or enforcement mechanism it is unclear how, if at all, the new statute will change how operators report unclaimed mineral interests to SITLA.

B. *Admin Code R850-21*

The Utah state regulations governing oil and gas had their first major revision since 2005 when SITLA repealed and replaced its oil and gas regulations, Utah Admin. Code R850-21, effective June 1, 2019. At first glance, the revisions appear to be primarily stylistic with shortened and simplified regulations and updated terminology. However, several newly created rules and revisions will have a more substantive effect.[29]

Although the entirety of U.A.C. R850-21 was repealed and replaced, the majority of the substantive changes occurred to the following rules: (1) 175 (Definitions);[30] (2) 500 (Lease Provisions);[31] and (3) 600 (Transfer by Assignment or Operation of Law).[32]

Revisions to Rule 175 include redefining various subparts of the oil and gas leasehold estate for record title,[33] removing definitions for "non-working interests" and "working interests,"[34] and adding new definitions for "operating rights" and "diligent operations."[35] The newly created definition for "diligent operations" allows for a limited cessation of operations that "do not exceed ninety (90) days in

28. UTAH CODE ANN. § 75-2-105(6) (a-b) (West 2019).
29. *See, e.g.,* UTAH ADMIN. CODE R. 850-21-500 (2019) (changing the minimal annual rental from $40 to $500); *see also* UTAH ADMIN. CODE R. 850-21-175(5) (2019) (defining what qualifies as diligent operations).
30. UTAH ADMIN. CODE R. 850-21-175 (2019).
31. UTAH ADMIN. CODE R. 850-21-500 (2019).
32. UTAH ADMIN. CODE R. 850-21-600 (2019).
33. UTAH ADMIN. CODE R. 850-21-175(13) (2019)..
34. *See* UTAH ADMIN. CODE R. 850-21-175(4)(c) & (e) (2004).
35. UTAH ADMIN. CODE R. 850-21-175(5) & (10) (2019).

duration" or a "cumulative period in excess of one hundred eighty (180) days" within a lease absent agency approval.[36]

Changes to lease provisions, found in Rule 500, include revisions to the annual lease rental, lease primary terms, minimum royalty production rates, retention of records, and requirements for lease extensions. The new minimum annual lease rental, regardless of acreage, increased from $40 to $500.[37] The new rules remove the limitation that the primary term for a lease not exceed ten years.[38] Similarly, the new rules are silent as to a minimum production royalty rate, which was previously required to be 2.5% of the gross proceeds.[39] SITLA is now required to retain records for seven years, an increase from the previous six years.[40] Leases are no longer automatically extended by inclusion in a SITLA approved unit plan for development or operation.[41] However, the new rules provide for an extension of two years, or until the end of the primary term, whichever is longer, for those leases in active units that terminate or contract on/or before January 1, 2021.[42] Leases that are committed to a new unit formed after the rules effective date of June 1, 2019, will not be entitled to this automatic extension.[43]

The regulations related to transfers and assignments were also modified. For instance, overriding royalty assignments are defined as "non-leasehold assignments" and must be filed with SITLA but only for record keeping purposes.[44] Filing of other non-leasehold assignments is not required, although they may be filed with SITLA for record keeping purposes.[45] Assignments are now considered effective upon approval by SITLA.[46] SITLA is also given the authority to "void" any assignment in which the certification of net revenue interest is false or where the aggregate burden is in excess of 20%.[47]

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36. UTAH ADMIN. CODE R. 850-21-175(5) (2019).
37. UTAH ADMIN. CODE R. 850-21-500(1)(b) (2019).
38. UTAH ADMIN. CODE R. 850-21-500(3) (2004).
39. UTAH ADMIN. CODE R. 850-21-500(2) (2004).
40. *Compare* UTAH ADMIN. CODE R. 850-21-500(7)(d) (2004) *with* UTAH ADMIN. CODE R. 850-21-500(5)(c) (2019).
41. *Compare* UTAH ADMIN. CODE R. 850-21-500(5)(d) (2004) *with* UTAH ADMIN. CODE R. 850-21-500(3) (2019).
42. UTAH ADMIN. CODE R. 850-21-500(3)(e)(i)(ii) (2019).
43. *Id*.
44. UTAH ADMIN. CODE R. 850-21-600(2) (2019).
45. *Id*.
46. UTAH ADMIN. CODE R. 850-21-600(3)(d) (2019).
47. UTAH ADMIN. CODE R. 850-21-600(3)(f) (2019).

The effects of the new regulations are expected to be minor. The majority of the revisions, including those highlighted above, incorporate long standing agency practices.

VIRGINIA

Mason E. Heidt & Joshua Wysor†

I. INTRODUCTION

This Article addresses developments in Virginia oil and gas law for the period from July 31, 2014 to July 31, 2019. This period is longer than normally addressed by this journal to capture important developments in the law between this update and the last Virginia update published in 2015. At the state level, in *Swords Creek Land Partnership v. Belcher*, the Supreme Court of Virginia concluded coalbed methane ("CBM") is a separate and distinct mineral estate from coal. It held that the meaning of "coal" within an 1887 severance deed was unambiguous and did not intend to convey ownership rights to the CBM.[1] This decision reaffirmed and expanded the Court's previous holding in *Harrison-Wyatt*.[2] In *Dye v. CNX Gas Co.,* the

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Swords Creek Land P'ship v. Belcher, 762 S.E.2d 570, 572–73 (Va. 2014).

2. *Id.* at 572; *see* Harrison-Wyatt, LLC v. Ratliff, 593 S.E.2d 234, 238 (Va. 2004) (holding that CBM within the GOB is a separate estate not passing by a coal-only severance deed).

Court held that a deed conveying "all coal and minerals" was also unambiguous and with the addition of the "and minerals" language constituted a transfer of CBM.[3]

During this period, the Court also ruled on a number of issues relating to the now-pending Atlantic Coast Pipeline ("ACP"). In *Chaffins v. Atlantic Coast Pipeline, LLC*, the Court was asked to determine whether ACP's "notices of intent" to enter landowners' properties to conduct preliminary surveys complied with state requirements, specifically whether the notices "set forth the date of the intended entry" as mandated by statute.[4] The Court held that such notices must set forth a sufficiently definite period for anticipated entry, and that ACP's stated intent to arrive "on or after" a specified date to perform such studies was inadequate.[5] In *Palmer v. Atlantic Coast Pipeline, LLC*, the Court faced two questions: (1) whether *foreign* corporations may exercise the same "entry-for-survey" power described above in *Chaffins*; and (2) whether the statutory provision allowing such authority became unconstitutional in light of post-*Kelo* amendments to the Virginia Constitution.[6] As to the former, the Court held that foreign corporations possess the same entry rights as domestic corporations.[7] As to the latter, the Court held that the post-*Kelo* amendments did not create a constitutional right to exclude ACP from access to landowners' properties.[8] Finally, in *Barr v. Atlantic Coast Pipeline, LLC*, the Court addressed a trial court's statutory interpretation of the entry-for-survey provision, holding that the statute should be read in such a way as to grant natural gas companies at least some discretion in determining the most advantageous pipeline routes.[9] Additionally, the Court reaffirmed the constitutionality of the survey provision, holding that such surveys do not violate the state constitution's takings clause.[10] The Court held that the use of a defined date "range" (as opposed to a singular date) in a notice-of-intent letter did not violate the statute's "date of . . . intended entry" requirement.[11]

3. Dye v. CNX Gas Co., 784 S.E.2d 703, 706 (Va. 2016).
4. Chaffins v. Atl. Coast Pipeline, LLC, 801 S.E.2d 189, 190 (Va. 2017) (quoting VA. CODE § 56–49.01(C)).
5. *Id.* at 193.
6. Palmer v. Atl. Coast Pipeline, LLC, 801 S.E.2d 414, 415, 418 (Va. 2017); *see* VA. CONST. art. I, § 11.
7. *Id.* at 417.
8. *Id.* at 419.
9. Barr v. Atl. Coast Pipeline, LLC, 815 S.E.2d 783, 789 (Va. 2018).
10. *Id.* at 790.
11. *Id.* at 791–92 (*compare with* Chaffins v. Atl. Coast Pipeline, LLC, 801 S.E.2d 189, 193 (Va. 2017) (holding that "on or after" language was impermissible

Finally, a more recent case was heard in the Fourth Circuit regarding the ability of the Forest Service to issue a Special Use Permit and Record of Decision allowing the Atlantic Coast Pipeline to pass through National Forest land and across the Appalachian Trail. Following the Fourth Circuit's decision, the case was granted certiorari for review by the United States Supreme Court, which is now pending.[12]

At the federal level, courts are continuing to navigate the legal quagmire created by *EQT Production Co., v. Adair*[13] and its progeny. Consisting originally of five cases—three with plaintiffs against EQT Production Company ("EQT") and two with plaintiffs against CNX Gas Company, LLC ("CNX")—these cases centered around the issue of class certifications under Federal Rule of Civil Procedure 23(a).[14] Specifically, plaintiffs sought to assert CBM royalty claims against the respective companies.[15] After the Western District of Virginia certified each of the five classes in 2013, the United States Court of Appeals for the Fourth Circuit remanded the cases for a "more rigorous analysis" to determine whether the requirements for class certification had been satisfied.[16] On remand, the Western District certified three of the classes in part (the *Hale*, *Adair*, and *Adkins* classes) and denied certification for the *Addison* and *Kiser* classes.[17] These cases and their impacts are discussed in further detail in Part IV.

II. MINERAL RIGHTS AFTER *SWORDS CREEK* AND *DYE*

In 1990, the Virginia Gas and Oil Act was amended to permit CBM production to go forward in cases where there was conflict or uncertainty as to the ownership of the CBM produced through the use of forced pooling.[18] Following pooling, royalties for conflicting claimants were placed in escrow. The funds remain in escrow until

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due to indefiniteness)).

12. *See* Cowpasture River Pres. Ass'n v. Forest Serv., 911 F.3d 150 (4th Cir. 2018), *cert. granted sub nom.* U.S. Forest Serv. v. Cowpasture River Pres. Assn., No. 18-1584, 2019 WL 4889926 (Oct. 4, 2019), and *cert. granted sub nom.* Atl. Coast Pipeline, LLC v. Cowpasture River Pres. Assn., No. 18-1587, 2019 WL 4889930 (Oct. 4, 2019).

13. *See* EQT Prod. Co. v. Adair, 764 F.3d 347 (4th Cir. 2014).

14. Adair v. EQT Prod. Co., 320 F.R.D. 379, 387 (W.D. Va. 2017).

15. *Id.* at 388.

16. *Id*. (citing *EQT Prod. Co. v. Adair*, 764 F.3d at 352).

17. *Id.* at 387.

18. Swords Creek Land P'ship v. Belcher, 762 S.E.2d 570, 571 (Va. 2014); *see* VA. CODE § 45.1-361.1 (2019).

conflicting claimants reach a voluntary settlement, the claimants' interests have been determined by a court of competent jurisdiction, or a final arbitration award has been granted pursuant to state statute.[19] Many of the original conflicting claims are centered around who owns the CBM following a severance of the Coal; Coal and Minerals; or a more exhaustive list of resources.[20]

In *Swords Creek*, the primary issue centered around an 1887 severance deed in which the original grantors conveyed "all of the coal, in, upon, or underlying a certain tract of land."[21] The parties to this appeal were Dollie Belcher, Doris Dye, and Ruby Lawson, successors-in-interest to the grantors (*i.e.* the surface owners), and Swords Creek Land Partnership, the successor-in-interest to the grantees (*i.e.* the coal owner).[22] In 1991, the Partnership entered into a lease agreement which allowed for the extraction of CBM at a royalty rate of 12.5% of the value of the gas produced.[23] In 1992, CNX Gas, LLC, the lessee, petitioned to have a pooling order entered and began production.[24] Royalty payments due to the CBM owners accrued in escrow for nearly twenty years because of conflicting claims. In 2011, the surface owners filed suit in circuit court, alleging that they were the sole owners of the CBM produced and therefore entitled to all existing and future royalty payments.[25] In 2013, the court entered a declaratory judgment awarding ownership of the CBM and its royalties to the surface owners.[26] In its decision, the circuit court held that the language of the 1887 severance deed was "unambiguous" in that it conveyed only the coal and *not* the associated CBM.[27]

On appeal, the Supreme Court of Virginia determined whether the original conveyance of "coal" also included a conveyance of the CBM. A decade prior to *Swords Creek*, in *Harrison-Wyatt, LLC v. Ratliff*, the Court held that a severance deed containing similar language was intended to convey only solid coal, and that the future value of CBM would not have been contemplated in the late 19th century, thereby excluding the possibility that the severance deed

19. *Swords Creek*, 762 S.E.2d at 571; *see* VA. CODE § 45.1-361.22:1 (2019).
20. *See generally The 2010 Pulitzer Prize Winner for Public Service: Bristol Herald Courier*, PULITZER.ORG, https://www.pulitzer.org/winners/bristol-va-herald-courier [https://perma.cc/7MFL-VTMM] (last visited Oct. 2019).
21. *Swords Creek*, 762 S.E.2d at 570.
22. *Id.* at 571.
23. *Id.*
24. *Id.*
25. *Id.*
26. *Id.* at 572.
27. *Id.* at 571–572.

grantor intended to convey it.[28] Further, the Court in *Harrison-Wyatt* stated, "[A]lthough CBM has a weak physical attraction to coal and escapes from coal when coal is mined, it is a gas that exists freely in the coal seam and is a distinct mineral estate."[29] In *Swords Creek*, the Court reaffirmed this decision, holding that the CBM belonged solely to the surface owners.[30] Whereas the CBM in question in *Harrison-Wyatt* was contained in the gob—a mined out area that could be accessed by merely drilling into the void—the gas in *Swords Creek* was accessed from unmined coal through the use of hydraulic fracturing. [31] Notably, the Court in *Swords Creek* did not answer the question of whether a CBM owner has the right to fracture a coal seam to access its gas estate as this issue was not raised at trial or on appeal.[32]

Note that in 2010, Virginia General Assembly passed legislation deeming that a "conveyance, reservation, or exception of coal" does not include CBM. [33] However, this statute does not retroactively affect prior conveyances and therefore did not control the *Swords Creek* decision.

Note also that, in 2015, the Virginia General Assembly passed legislation designed to remove from escrow accrued royalties resulting from conflicting claims of CBM ownership.[34] Operators of force-pooled gas wells were required to apply to the Virginia Gas and Oil Board for release of the escrowed funds to the gas-claimant and send notice of the application to the coal- owning-claimants.[35] Within forty-five days, the coal claimant had to provide evidence of a pending proceeding or an agreement with the gas claimant to split royalties.[36] If the coal claimant provided neither or did not respond within the allotted time, all future royalties and escrowed past royalties were distributed to the gas claimant, usually the surface owner.[37] This

28. *Id.* at 572.
29. *Id.* (quoting Harrison-Wyatt, LLC v. Ratliff, 593 S.E.2d 234, 238 (Va. 2004)).
30. *Id.* at 573.
31. *Id.* at 572.
32. *Id.* at 573.
33. VA. CODE ANN. § 45.1-361.21:1 (2019).
34. VA. CODE ANN. § 45.1-361.22:2 (2019).
35. *Id.*
36. *Id.;* Note that, in order to resolve the conflicting claims and prevent royalties from accumulating in escrow, some surface owners and coal owners, given the uncertainty in the law prior to *Swords Creek*, had entered into "Split Agreements" whereby the coal owner and surface owner voluntarily agreed to split royalties.
37. *Id.*

legislation successfully significantly reduced the amount of funds held in escrow.

The Supreme Court of Virginia again took up the task of interpreting the language of 19th century conveyances in 2016, this time evaluating the meaning of "minerals" within two separate severance deeds. In *Dye*, the Court examined two severance deeds from 1886 and 1887, respectively, both of which conveyed "all of the coal and minerals" underlying tracts in Buchanan and Russell counties.[38] In her complaint, Nella Dye, successor-in-interest to the property rights maintained by the original grantors, alleged that the 1886 and 1887 conveyances were not intended to sever or convey the underlying natural gas.[39]

Buckhorn Coal Company, successor-in-interest to the property rights conveyed to the original severance grantees, and CNX (a lessee of Buckhorn's interest), filed demurrers to Dye's complaint. Both Buckhorn and CNX alleged that under established case precedent, a broad conveyance of "minerals" included natural gas.[40] Specifically, the demurrers cited *Warren v. Clinchfield Coal Corp.*, a 1936 Virginia Supreme Court decision in which the Court defined petroleum, oil, and gas as "minerals" for the purposes of an 1887 severance deed.[41] Dye, in turn, claimed that the term "minerals" is ambiguous, a claim which, if sustained, would allow the introduction of extrinsic evidence to prove the grantor's intent.[42] In *Dye*, the circuit court sustained appellees' demurrers, citing the Court's previous holding in *Warren*.[43] In affirming the circuit court's holding, the Supreme Court of Virginia noted that the *Warren* decision follows the majority rule in most jurisdictions, i.e., a conveyance of "minerals" conveys all minerals, including CBM gas, unless a different intent is shown or other language in the deed "creates sufficient ambiguity to permit the introduction of extrinsic evidence." [44]

III. THE ATLANTIC COAST PIPELINE CASES

38. Dye v. CNX Gas Co., 784 S.E.2d 703, 704 (Va. 2016) (Note that the 1887 deed conveyed "all of the coal and *other* minerals").
39. *Id.*
40. *Id.*
41. *Warren v. Clinchfield Coal Corp.*, 186 S.E.2d 20, 21 (Va. 1936).
42. *Dye*, 784 S.E.2d at 704.
43. *Id.* at 704–705.
44. *Id.* at 706 n.2.

Between 2017 and 2018, the Supreme Court of Virginia heard three cases concerning ACP-related property surveys and environmental studies. In each case, the issues centered around the interpretation and/or constitutionality of Virginia Code Section 56-49.01, which authorizes "certain natural gas companies to enter upon property, *without permission*, for examinations, tests, hand auger borings, appraisals and surveys."[45]

In *Chaffins*, appellant-landowners received letters from ACP seeking permission to enter their properties to conduct preliminary surveys and studies.[46] ACP explained that conducting the surveys and environmental studies was "required as part of the permitting process for the pipeline."[47] When the landowners refused, ACP provided notices indicating its intent to enter the properties "on or after April 27, 2015" pursuant to Virginia Code Section 56-49.01.[48] ACP then filed petitions for declaratory judgment against the landowners, alleging its right to enter landowners' properties.[49] Landowners responded by filing demurrers, arguing in part that the notices failed to set forth "the date of the intended entry," as required by statute.[50] The circuit court overruled the demurrers, finding there was "no flaw in the notification process."[51] When ACP's petition proceeded to a hearing on the merits, the circuit court again rejected appellants' argument, holding that the notices need only provide a "hope[ful]" date of entry that "may have to change" depending on factors such as weather and workloads at other properties.[52] On appeal, the Supreme Court of Virginia emphasized that at each step of the notice process, state statute requires at least fifteen days' advance notice to landowners prior to entering private property.[53] In this context, the Court concluded, the notices' proposed dates of entry must be definite in order to be valid. ACP's use of "on or after" language did not meet this standard. Thus, the decision of the circuit court was reversed.[54]

In *Palmer*, the appellant, Hazel Palmer, owned real property in Virginia along one of the ACP's proposed routes.[55] On March 6, 2015,

45. Chaffins v. Atl. Coast Pipeline, 801 S.E.2d 189, 190 (Va. 2017).
46. *Id.*
47. *Id.*
48. *Id.*
49. *Id.*
50. *Id.* (quoting VA. CODE ANN. § 56-49.01(C) (2019)).
51. *Id.*
52. *Id.*
53. *Id*. at 191; *see* VA. CODE ANN. §§ 56-49.01(A)-(C) (2019).
54. *Id.*
55. Palmer v. Atl. Coast Pipeline, 801 S.E.2d 414, 415 (Va. 2017).

ACP sent Palmer a letter seeking permission to enter her property in order to conduct preliminary surveys.[56] After Palmer refused, ACP provided a notice of intent pursuant to Virginia Code Section 56-49.01.[57] Palmer continued to refuse access, and ACP subsequently filed a petition for declaratory judgment asserting ACP's rights to access and survey the property.[58] Palmer responded by filing a plea at bar, alleging in her complaint that Virginia Code Section 56-49.01 only applied to *domestic* public service companies because the statute is located within Title 56 of the Code of Virginia.[59] Additionally, Palmer filed a demurrer, arguing that the statute was unconstitutional in light of post-*Kelo* amendments to Article I, Section 11 of the Constitution of Virginia.[60] The circuit court rejected both of Palmer's arguments, concluding that the statute's placement within Title 56 did not amount to an "implied definition" of what constitutes a natural gas company.[61] Further, the court held that similar constitutionality arguments alleging takings without just compensation have been "consistently rejected."[62]

On appeal, the Supreme Court of Virginia held that the rights and privileges contained in Virginia Code Section 56-49.01 extend to both domestic *and* foreign corporations.[63] The Court cited Virginia Code Section 56-1, which defined corporations as "all corporations . . . doing business [in the Commonwealth]."[64] The Court then addressed a second argument by Palmer concerning Article IX, Section 5 of the Constitution of Virginia. Specifically, this Section declares that "[n]o foreign corporation shall be authorized to carry on in this Commonwealth the business of, or to exercise any of the powers or functions of, a public service enterprise."[65] While potentially persuasive, the Court was barred from considering this argument, having neither been presented at the circuit court nor raised in

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56. *Id.* at 415–16.
57. *Id.* at 416.
58. *Id.*
59. *Id.*
60. *Id.*
61. *Id*.
62. *Id.* (quoting Charlottesville Div. v. Dominion Transmission, Inc., 138 F. Supp. 3d 673, 690 (W.D. Va. 2015)).
63. *Id.* at 417.
64. *Id.* (quoting VA. CODE § 56-1 (2016)); *see* 15 U.S.C. § 717(a)(6) (2012) (defining a "natural gas company" as any gas company "engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale").
65. *Id.* (quoting VA. CONST. art. IX, § 5).

appellant's opening brief on appeal.[66] Finally, the Court considered whether Virginia Code Section 56-49.01 violated post-*Kelo*[67] revisions to Article I, Section 11 of the Constitution of Virginia. In addressing this issue, the Court cited the common law privilege to enter private property for limited purposes.[68] As stated by the American Law Institute, the privilege applies "where an employee of a public utility is . . . authorized to enter upon privately owned land *for the purpose of making surveys* preliminary to instituting a proceeding for taking by eminent domain."[69] Further, the Court noted, the common law privilege to enter property for the limited purpose of surveys has been codified in Virginia law for at least 235 years.[70] Consequently, the Court concluded that Palmer's right to exclude others from her private property was not absolute.[71] Thus, the holding of the circuit court was affirmed.[72]

In *Barr*, the Supreme Court of Virginia again faced interpreting the language of Virginia Code Section 56-49.01, this time considering whether ACP was only entitled to conduct activities that were "necessary" to the selection of the most advantageous pipeline route.[73] Similar to *Chaffins* and *Palmer*, appellant-landowners received letters from ACP requesting access to their properties for the limited purpose of conducting preliminary surveys.[74] After being denied access, ACP sent letters of intent to exercise its authority pursuant to Virginia Code Section 56-49.01.[75] ACP then filed petitions for declaratory judgment against the landowners, seeking affirmation of its rights under the statute.[76] The landowners demurred, alleging *inter alia* that ACP failed to meet statutory requirements and that such entry represented an unconstitutional taking in violation of the Fifth Amendment to the United States Constitution and Article I, Section 11 of the Virginia Constitution.[77] The circuit court rejected appellants' constitutionality arguments, noting that the statute did not provide ACP with an "unlimited right of entry with regard to date, scope, or

66. *Id*.
67. *See generally* Kelo v. City of New London, 545 U.S. 469 (2005).
68. *Palmer*, 801 S.E.2d at 418.
69. *Id.* (quoting Restatement of Torts § 211 cmt. c (1934) (emphasis added).
70. *Id.* at 418–19.
71. *Id.* at 419.
72. *Id.* at 420.
73. Barr v. Atl. Coast Pipeline, 815 S.E.2d 783, 784 (Va. 2018).
74. *Id.*
75. *Id.*
76. *Id.*
77. *Id.*

duration."[78] However, the trial court did conclude that ACP's notices of intent were deficient under Virginia Code Section 56-49.01(A), as they did not indicate the specified dates that ACP would enter the properties.[79] After amending its notices, ACP filed a second petition for declaratory judgment against appellant-landowners.[80] Again, the landowners filed demurrers—which were rejected by the trial court—followed by responsive pleadings.[81] At trial, the landowners' primary, and perhaps most persuasive, argument centered around a "disjunctive," as opposed to "conjunctive" interpretation of Virginia Code Section 56-49.01. The language at issue states that corporations may conduct surveys "as are necessary (i) to satisfy any regulatory requirements and (ii) for the selection of the most advantageous location or route."[82] Under a conjunctive approach (as proposed by appellants), ACP would be required to satisfy the requirements of both (i) and (ii) to exercise a lawful right of entry. Under appellants' theory, ACP failed to demonstrate that it had pre-selected the most advantageous route and was thus unable to enter the landowners' private property. However, under a disjunctive approach ACP need only satisfy one of the requirements to exercise a right of entry. This was the interpretation adopted by the trial court.[83]

On appeal, the Supreme Court of Virginia affirmed the trial court's use of the disjunctive approach, stating that to rule otherwise would counter state legislative intent and "render certain portions of the statute meaningless."[84] For example, the Court wrote that certain activities under romanette (ii) are necessarily performed independent of the satisfaction of regulatory requirements under romanette (i).[85] Thus, the Court held, it would be illogical to interpret the statute using a conjunctive approach.[86] Determining that ACP's proposed entry onto landowners' properties was lawful under the trial court's disjunctive interpretation, the Court did not have to reach the question of whether an unlawful taking had occurred.[87] Thus, the ruling of the circuit court was affirmed.[88]

78. *Id.* at 785.
79. *Id.*; *cf. Chaffins v. Atl. Coast Pipeline*, 801 S.E.2d 189 (Va. 2017).
80. *Barr*, 815 S.E.2d at 785.
81. *Id.*
82. VA. CODE § 56-49.01(A) (2019).
83. *Barr*, 815 S.E.2d at 786.
84. *Id.* at 788–89.
85. *Id.* at 789.
86. *Id.* at 790.
87. *Id.* at 792.
88. *Id.*

In *Cowpasture River Preservation Association v. Forest Service*, the Fourth Circuit considered whether the United States Forest Service had "complied with the National Forest Management Act, the National Environmental Policy Act, and the Mineral Leasing Act in issuing a Special Use Permit and Record of Decision authorizing Atlantic Coast Pipeline, LLC, the project developer, to construct the Atlantic Coast Pipeline through parts of the George Washington and Monongahela National Forests and granting a right of way across the Appalachian National Scenic Trail."[89]

The Court considered whether the Forest Service's granting of the Special Use Permit and Record of Decision was arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law.[90] After an extensive review of the permitting process and finding failures in the process at several points, the court found:

A thorough review of the record leads to the necessary conclusion that the Forest Service abdicated its responsibility to preserve national forest resources. This conclusion is particularly informed by the Forest Service's serious environmental concerns that were suddenly, and mysteriously, assuaged in time to meet a private pipeline company's deadlines.[91]

The Forest Service's decisions regarding the Special Use Permit and Record of Decision were vacated and the issue remanded to the Forest Service for further proceedings. Following appeal, writs of certiorari have been granted for review by the Supreme Court of the United States.[92]

IV. *ADAIR* AND SUBSEQUENT DEVELOPMENTS

The federal *Adair* cases have developed a long and complex procedural history with the first complaint going back as far as June 2010.[93] The cases consist of five then-proposed classes (*Hale*, *Adair*, *Adkins*, *Addison*, and *Kiser*), each alleging its class members were unlawfully deprived of CBM royalty payments owed to them by either EQT or CNX. On September 30, 2013, each of the five classes were

89. Cowpasture River Pres. Ass'n v. Forest Serv., 911 F.3d 150, 154–55 (4th Cir. 2018).
90. *Id*. at 160.
91. *Id*. at 183.
92. Forest Service v. Cowpasture River Pres. Ass'n, No. 18-1584, 2019 WL 4889926 (U.S. Oct. 4, 2019); Atlantic Coast Pipeline, LLC v. Cowpasture River Pres. Ass'n, No. 18-1587, 2019 WL 4889930 (U.S. Oct. 4, 2019).
93. EQT Prod. Co. v. Adair, 764 F.3d 347, 355 (4th Cir. 2014).

certified in the United States District Court for the Western District of Virginia pursuant to Federal Rules of Civil Procedure 23(a), 23(b)(2), and 23(b)(3).[94]

On appeal, the United States Court of Appeals for the Fourth Circuit vacated and remanded the five class certifications for further analysis by the district court.[95] In its decision, the Fourth Circuit provided a five-factor test in determining whether to grant a class certification. These factors are:

> (1) whether the certification ruling is likely dispositive of the litigation; (2) whether the district court's certification decision contains a substantial weakness; (3) whether the appeal will permit the resolution of an unsettled legal question of general importance; (4) the nature and status of the litigation before the district court (such as the presence of outstanding dispositive motions and the status of discovery); and (5) the likelihood that future events will make appellate review more or less appropriate.[96]

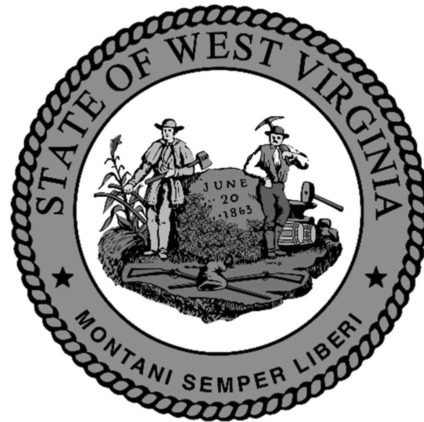
In its conclusion, the Fourth Circuit determined that the district court's analysis "lacked the requisite rigor to ensure the requirements of Rule 23 were satisfied by any of the certified classes."[97] However, the court did not preclude the possibility of the district court regranting certification to one or more classes.[98] The court simply held that the original certifications by the district court had been premature.

On remand, the district court granted certifications in part to the *Hale*, *Adair*, and *Adkins* classes and denied certification to the *Addison* and *Kiser* classes.[99] After a nearly fifty-page analysis, the district court set out the allowed issues under each certification. The *Hale* class was certified as to the following issues: (1) allegedly excessive deductions; (2) royalties based on allegedly improperly low prices; (3) deduction of severance taxes; and (4) request for an accounting.[100] The *Adair* class was certified as to all of the issues in

94. *See* Adkins v. EQT Prod. Co., 2013 U.S. Dist. LEXIS 140623 (W.D. Va., Sept. 30, 2013); Addison v. CNX Gas Co., 2013 U.S. Dist. LEXIS 140622 (W.D. Va., Sept. 30, 2013); Hale v. CNX Gas Co., 2013 U.S. Dist. LEXIS 140617 (W.D. Va., Sept. 30, 2013); Adair v. EQT Prod. Co., 2013 U.S. Dist. LEXIS 140611 (W.D. Va., Sept. 30, 2013); Legard v. EQT Prod. Co., 2013 U.S. Dist. LEXIS 140618 (W.D. Va., Sept. 30, 2013).
95. *EQT Prod. Co.*, 764 F.3d at 371.
96. *Id.* at 357 (quoting Lienhart v. Dryvit Sys., Inc., 255 F.3d 138, 145 (4th Cir. 2001)).
97. *Id.* at 371.
98. *Id.*
99. Adair v. EQT Prod. Co., 320 F.R.D. 379, 429–430 (W.D. Va. 2017).
100. *Id.* at 429.

the *Hale* class except the claim of allegedly excessive deductions.[101] Finally, the *Adkins* class was certified as to (1) allegedly improper deduction of marketability costs and (2) royalties based on improperly low prices.[102] Following resolution of the class certification issue, *Hale* and *Adair* were each dismissed in 2019 upon reaching a negotiated class settlement. *Addison*, *Adkins,* and *Kiser* were dismissed upon stipulation of the parties in 2019.

101. *Id.* at 430.
102. *Id.*



OIL & GAS SURVEY: WEST VIRGINIA

Joshua P. Fershee[*]

This Article summarizes and discusses important recent developments in West Virginia's oil and gas law as determined by recent West Virginia Supreme Court of Appeals cases. There were no substantial legislative changes in the current period.

I. ANDREWS V. ANTERO RESOURCES CORPORATION

In *Andrews v. Antero Res. Corp.*, Antero Resources Corporation ("Antero") derived leasehold rights to develop mineral resources in Harrison County, West Virginia, through a severance deed.[1] The severance deed was executed in the early 1900s and listed

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1. 828 S.E.2d 858, 861 (W. Va. 2019).

certain rights, including the right to drill, bore, and operate oil and gas wells.[2]

The Petitioners represented holders of the surface rights on properties near Antero's drilling activities and alleged that Antero's mineral operations interfered with the Petitioners use and enjoyment of the land.[3] Specifically, the Petitioners pointed to the annoyance, inconvenience, and discomfort caused by heavy equipment, diesel fumes, and other emissions from traffic, and there was no allegation of property damage.[4] The Petitioners asserted that the operator did not have the right to extract natural gas using methods like horizonal drilling and hydraulic fracturing, which were not contemplated when the severance deeds were executed in the 1900s.[5] Further, they asserted, even where the drilling operations were located off-site of the Petitioners' surface estate, Antero had substantially interfered with the Petitioners' use and enjoyment of their surface estate.[6]

Under West Virginia law, the owner of mineral rights possesses the right to use the surface in a manner and with such means as would be fairly necessary for the enjoyment of the mineral estate.[7] However, for an owner of mineral resources to access an implied easement for surface rights, it must be demonstrated not only that the right is reasonably necessary for the extraction of the mineral, but also that the right can be exercised without substantial burden to the surface owner.[8]

In this case, Antero's off-site horizontal drilling operations did not cause any substantial burden because Antero was within its rights to use the surface land to access the minerals below.[9] The court, consistent with prior rulings, determined that building roads and well pads and drilling wells was reasonably necessary for the extraction of natural gas.[10] Although horizontal drilling was not envisioned at the time of deed formation (mineral owners only anticipated the impacts of vertical drilling), expert testimony revealed that horizontal drilling

2. *Id.*
3. *Id.* at 862.
4. *Id.*
5. *Id.* at 864.
6. *Id.* at 865.
7. *Id.*
8. *Id.* at 870.
9. *Id.* at 872.
10. *Id.* at 873.

has less of a surface impact than traditional vertical drilling.[11] Furthermore, because the drilling operations were located off-site of the Petitioners' surface estates, the claim was even more attenuated.[12]

This case further confirms that under West Virginia law, both horizontal and vertical drilling operations constitute surface use in a manner reasonably necessary to extract natural gas.[13]

II. KUPFER V. CHESAPEAKE APPALACHIA, LLC

In *Kupfer v. Chesapeake Appalachia, LLC*, the Kupfers received ninety acres of land by deed in 1980.[14] The deed did not contain any oil and gas reservations. In 1990, the Kupfers conveyed eight parcels of land, plus an additional 60-acre parcel (the "ninth parcel") to Michael Blair.[15] The Petitioners' deed stated that the eight parcels were excepted and reserved from all coal, oil, gas, and other minerals, thus retaining those mineral rights from the eight parcels.[16] That deed later described the "ninth parcel" but made no reference to any reservations or exceptions as to the mineral rights.[17]

In September 2000, Michael Blair conveyed his interest in the ninth parcel to Zachary Blair using exactly the same language as the 1990 deed.[18] In 2009, Zachary Blair leased the oil and gas resources to Chesapeake Appalachia, LLC, which then sold and assigned the lease in 2014 to the current rights holder, SWN Production Company.[19] The language of the 1990 deed was preserved in subsequent conveyances, explicitly reserving and excepting the oil and gas resources for the eight parcels and separately referencing to the "ninth parcel" without mentioning a reservation.[20] In 2016, the Petitioners filed a complaint of trespass and conversion against the respondents claiming that they owned the oil and gas rights associated

11. *Id.* at 869.
12. *Id.*
13. *Id.*
14. No. 17-0527, 2018 WL 2175553, at *1 (W. Va. May 11, 2018).
15. *Id.*
16. *Id.*
17. *Id.* at *2.
18. *Id.*
19. *Id.*
20. *Id.*

with the "ninth parcel," asserting that those rights were also reserved in the 1990 deed.[21]

The Kupfers argued that "[a] deed of conveyance, in order to pass title, must contain a description of the property being conveyed which sufficiently identifies the land, either by the language of the granting clause itself or by reference to extrinsic facts which render the description certain."[22] Additionally, they argued that the subject deed provided lists of the parcels to be conveyed early in the document, and that language "completed the conveyance."[23] They further claimed that additional descriptions of the individual parcels appearing later in the deed were not needed.[24] Therefore, they claimed that if the later "unnecessary parcel by parcel description is removed," the remaining deed language was sufficient to identify what was conveyed, reserving and excepting oil and gas rights for all parcels, including the ninth parcel.[25]

The court disagreed, stating that "Petitioners' argument is fundamentally flawed in that it focuses on but one portion of the subject deed and fails to consider all of the parts together so as to give effect to the intention of the parties."[26] The court further explained, "it is axiomatic that '[p]arties are bound by general and ordinary meanings of words used in deeds.'"[27]

Under West Virginia law, in order to pass title, a deed of conveyance must contain a description of the property being conveyed that sufficiently identifies the land, either by the language of the grant clause itself or by reference to extrinsic facts that render description certain. Here, the deed contained a distinct description of parcels one through eight and includes language regarding the oil and gas reservations. However, the "ninth parcel" is described in a separate portion of the document, and the description is silent on oil and gas reservations. In this case, the court determined that the deed did not

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21. *Id.*
22. *Id.* at *3 (quoting Sally-Mike Props. v. Yokum, 332 S.E.2d 597, 602 (W. Va. 1985)).
23. *Id.*
24. *Id.* at *6–7.
25. *Id.* at *7.
26. *Id.* at *8.
27. *Id.* at *10. (quoting Syl. Pt. 1, McDonough Co. v. E.I. DuPont DeNemours & Co., Inc., 280 S.E.2d 246 (W. Va. 1981); Syl. Pt. 1, Meadows v. Belknap, 483 S.E.2d 826 (W. Va. 1997)).

reserve or except any coal, oil, or gas. As such, the Petitioners do not own the parcel of land, and therefore lack standing to bring forth any claim.

III. EQT PRODUCTION CO. V. CROWDER

A. *Facts*

Margot Beth Crowder and David Wentz own surface land ("Crowder Land") that had been part of a larger tract of land in Doddridge County, West Virginia. The mineral rights of that land were leased in 1901 to a predecessor of EQT Production Company ("EQT") to drill for oil and gas. EQT drilled horizontal wells on the Crowder Land surface that extended under neighboring properties and to natural gas. In 2011, EQT sought to pool the rights provided under the 1901 lease with other leases it held so it could drill and extract oil and gas on neighboring lands. EQT obtained a pooling clause in a modified deed in 2011 from the mineral owners but not from the surface owners of Crowder and Wentz.

EQT then drilled horizontal wells on the Crowder Land, which produced gas derived from neighboring properties. Crowder and Wentz sued, claiming that EQT's lease did not allow the company to use the Crowder Land surface estate to extract oil and gas from neighboring mineral estates. The lease did not have a pooling clause. Instead, the lease only granted permission to extract oil and gas from the mineral estate below the Crowder Land surface.

The Circuit Court of Doddridge County ruled in favor of Crowder and Wentz and entered an order granting partial summary judgment, finding that EQT trespassed when it used the Respondent's surface lands to conduct operations on neighboring properties. A jury awarded $190,000 in damages. EQT brought this appeal.

The high court determined that mineral lessees have "an implied right to use the surface of a tract in any way reasonable and necessary to the development of minerals underlying the tract."[28] It is worth noting that the court confirmed that the use of horizontal drilling and hydraulic fracturing is reasonable and necessary. However, the court continued, "a mineral owner or lessee does not have the right to

28. EQT Prod. Co. v. Crowder, 828 S.E.2d 800, 801 (W. Va. 2019).

use the surface to benefit mining or drilling operations on other lands, in the absence of an express agreement with the surface owner permitting those operations."[29]

In addition, the court explained that the owners of the mineral estate could not provide pooling rights to use the Crowder Land because the mineral owners "no longer owned the right to use the surface estate for exploration on and production from neighboring tracts."[30] The mineral estate had been severed from the surface in 1936, meaning the pooling right "was a right attached to the surface estate."[31]

This decision could (and should) have the effect of overruling a 2016 lower court decision. Back in April 2016, a West Virginia case ruled that there was an implied right to pool in oil and gas leases.[32] The *EQT* decision corrects this erroneous decision, which implied that all oil and gas leases come with an implied right of pooling.[33]

IV. L&D INVESTMENTS, INC. V. MIKE ROSS, INC.

Charles Lee Andrews ("Charles"), as trustee for his mother, Mary, held a fee simple title to two tracts of land.[34] The surface land was eventually divided among Mary's descendants, and the oil and gas wealth was conveyed to several different individuals.[35] A real

29. *Id.*
30. *Id.* At 810.
31. *Id.*
32. *There is an Implied Right to Pool an Oil and Gas Lease*, Jackson Kelly LLC Oil and Gas Update, https://oilandgas.jacksonkelly.com/2016/04/there-is-an-implied-right-to-pool-an-oil-and-gas-lease.html (April 20, 2016) (discussing *American Energy-Marcellus LLC v. Poling,* Circuit Court of Tyler County, West Virginia, Civil Action No. 15-C-34 H).
33. *See* Joshua P. Fershee, *Oil & Gas Survey: West Virginia*, 5 TEX. A&M J. PROP. L. 169 (2019); Taryn Phaneuf, *Professor says judge's opinion on implied pooling rights marks departure from state oil and gas law*, THE W. VA. REC. (Aug. 11, 2016), https://wvrecord.com/stories/510990698-professor-says-judge-s-opinion-on-implied-pooling-rights-marks-departure-from-state-oil-and-gas-law [https://perma.cc/6SEA-JX8G]; Robert J. Burnett & William J. Blakemore, *Pooling Clause Not Necessary: West Virginia Court Finds Implied Right to Pool Exists Where Lease Silent* (May 25, 2016), https://www.hh-law.com/driller-may-have-an-implied-right-to-pool-lease-where-no-pooling-clause-exists/ [https://perma.cc/HM55-C4SC] ("No court has ever recognized an implied covenant to pool.").
34. L&D Invs., Inc. v. Mike Ross, Inc., 818 S.E.2d 872, 875 (W. Va. 2018).
35. *Id.*

property tax assessment for 100% of the oil and gas interests remained solely in the name of Charles. Additional tax assessments were added to the Harrison County land books in 1988.[36] The assessment under the "master assessment" in Charles's name was paid each year through 1999.[37]

In 1999, several descendants claiming an interest in the oil and gas rights requested separation of their respective interests from the "master assessment."[38] The descendants paid their individual assessments each year, but the master assessment was not paid starting in 2000.[39] The master assessment became delinquent, and a tax lien on the property in the name of Charles was sold at a delinquent tax sale to Mike Ross, Inc ("MRI") in 2003.[40] In 2013, L&D investments ("Petitioners") purchased oil and gas interests from two of Mary's decedents. L&D expected oil and gas royalties from the purchase but then learned that MRI owned the assets through a delinquent tax sale.[41]

The circuit court granted summary judgment on the ground that the Petitioners' claims were barred by a three-year statute of limitations.[42] The Supreme Court of Appeals of West Virginia reversed, stating that "void tax sale deeds did not have a statute of limitations."[43] The Court further found that the circuit court erred by concluding that the petitioners' ownership interests were "legitimately sold out from under them."[44] Because of the double assessments and the payment of the taxes by the Petitioners, the court determined that the mineral interests were never delinquent, and the sale was void.[45]

V. STEAGER v. CONSOL ENERGY, INC.

Consol Energy, Inc., d/b/a CNX Gas Company, LLC ("Consol") and Antero Resources Corporation ("Antero") own multiple gas wells in several West Virginia counties.[46] The

36. *Id.* at 876.
37. *Id.*
38. *Id.* at 877.
39. *Id.*
40. *Id.*
41. *Id.*
42. *Id.* at 875.
43. *Id.* at 882.
44. *Id.* at 881.
45. *Id.*
46. Steager v. Consol Energy, Inc., 832 S.E.2d 135, 140 (W. Va. 2019).

Respondents (Consol and Antero) are the owners of traditional and horizontal gas wells.[47] The gas wells are assessed for *ad valorem* taxes based on a formula created by the West Virginia State Tax Commissioner, Dale W. Steager.[48] This case concerns the proper valuation of operating expense deductions for horizontal and traditional gas wells.[49]

Consol and Antero first claimed that the Tax Department imposed a cap on operating expense deductions.[50] The cap was described as both a percentage (30% for vertical wells and 20% for horizontal wells), and a monetary figure ($5,000 for vertical wells and $150,000 for horizontal wells).[51] The Court was asked to determine whether the West Virginia Code allows for a cap placed on operating expense deductions and if the cap can be described as both a percentage and dollar figure.[52]

Additionally, Consol and Antero argued that the operating expense deduction calculation, which did not include expenses associated with gathering, processing, and transporting the gas, resulted in an overvaluation of the gas wells.[53] Finally, the Court needed to decide whether a monetary average was the correct calculation of operating expense deductions as opposed to an unlimited percentage.[54]

The Court affirmed the business court's finding that the use of a "not to exceed" amount or "cap" on operating expense deductions was not supported by the West Virginia Code § 110-1J 4.3.[55] The cap singled out wells with higher gross receipts, and thus the cap applied a different percentage reduction for operating expenses. In doing so, the cap allowed the Tax Department to treat higher grossing and lower grossing wells differently and applied two different tax valuation methods depending on the well.[56] This was in violation of the West Virginia Constitution Article X, Section 1 "equal and uniform"

47. *Id.*
48. *Id.*
49. *Id.*
50. *Id.* at 141.
51. *Id.*
52. *Id.* at 140.
53. *Id.* at 142.
54. *Id.* at 140.
55. *Id.*
56. *Id.* at 142.

requirement, as well as the equal protection provisions of the West Virginia and United States Constitutions.[57]

Next, the Tax Department had restricted the definition of operating expenses to only include costs relating to the maintenance and production of gas.[58] However, the Tax Department calculated gross receipts at the point of sale, which they used to derive the tax on the producers.[59] The process of bringing gas to the point of sale subjected producers to more operating expenses, including transportation expenses.[60] Energy producers were not allowed to incorporate those transportation expenses in the operating expense calculation, meaning that the tax deduction for operating expenses did not include the total cost of bringing the gas to the market.[61]

The business court concluded that operating expenses should include gathering, compressing, processing, and transporting expenses; and the Supreme Court agreed. However, the business court failed to provide a remedy on this issue, so the court determined that the Tax Department's interpretation that the regulation includes post-production expenses as part of the annual industry average operating expenses was correct.[62]

Lastly, the Court concluded that a monetary average was the correct calculation for operating expenses, but that the monetary average should not be calculated as an unlimited percentage deduction for operating expenses.[63] The Court found that the language of the regulation plainly contemplated the use of a monetary average and not percentages.[64]

57. *Id.*
58. *Id.*
59. *Id.* at 143.
60. *Id.*
61. *Id.* at 142.
62. *Id.* at 148.
63. *Id.* at 151.
64. *Id.*

WYOMING

Walter F. Eggers, III, and Deanna (Sami) Falzone†

I. BACKGROUND

Wyoming currently ranks eighth nationally in both crude oil and natural gas production. In 2018, Wyoming produced 87.9 million barrels of crude oil, up from 75.7 million barrels in 2017. Wyoming produced 1.81 billion MCF (thousand cubic feet) of natural gas, increasing from 1.80 billion MCF produced in 2017.[1]

II. LEGISLATION

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1. *Wyoming's Oil & Gas Facts*, WYO. ST. GEOLOGICAL SURV. (2018), https://www.wsgs.wyo.gov/energy/oil-gas-facts [https://perma.cc/MB6Y-7C3V] (last visited Oct. 6, 2019).

Wyoming's 2019 General Legislative Session convened on January 8, 2019 and adjourned on February 28, 2019.[2] Wyoming legislators introduced several bills related to the oil and gas industry.

A. *Ad Valorem Tax Exemption—Energy Production Inventory Exemption*

The legislature granted an exemption for equipment temporarily stored in Wyoming prior to its first installation as energy production equipment. The exemption only applies if the party who purchased the equipment paid Wyoming sales or use tax for the equipment at the county's tax rate where the equipment is being stored. "Energy production equipment" is defined as:

> any specialized equipment designed specifically for use in the production of energy from natural gas, coal, oil, wind, solar, hydro or nuclear sources but shall not include any equipment used to store or transport energy products, mobile energy product equipment, standard building materials, construction equipment or other equipment or materials that will not be directly used in the production of energy.[3]

B. *Ad Valorem/Gross Products Taxes - Mineral Production Tax Lien Priority*

The legislature strengthened Wyoming's tax lien laws on mineral production for ad valorem/gross products tax purposes. Wyoming counties collect the ad valorem/gross products tax. The revisions to the lien statute require that for oil, gas, and other mineral production on or after January 1, 2021, the county's lien is "perpetual" and "attaches and is perfected immediately upon production of the

2. *Prior Session Calendars,* WYO. LEGIS. SERVS. OFF., https://www.wyoleg.gov/Session/ 2019/Archive [https://perma.cc/Z729-Z3JG] (last visited Oct. 6, 2019).

3. This bill was vetoed by the Governor of Wyoming, and therefore there is no Session Law for the bill. It can be found at *HB0120 – Energy Production Inventory Exemption*, WYO. LEGIS. SERVS. OFF., https://www.wyoleg.gov/Legislation/2019/HB0120 [https://perma.cc/3SAV-5FNN] (last visited Oct. 13, 2019).

mineral subject to all prior existing liens." Prior to this amendment to the lien statute, a county was required to file, attach, and perfect the lien through a filing process.[4]

C. *Wyoming Energy Authority*

The legislature created the Wyoming Energy Authority by merging the existing Wyoming Infrastructure Authority ("WIA") and the Wyoming Pipeline Authority ("WPA"). The WIA worked to expand Wyoming's economy through transmission projects and improvements. The WPA promoted pipeline systems to encourage production, transportation, distribution, and the delivery of oil and gas. The new Wyoming Energy Authority will have many of the same goals and duties as the WIA and WPA.[5] The legislation requires the executive director of the WIA to prepare a reorganization plan and to submit the plan to the legislature's Joint Minerals, Business and Economic Development Interim Committee by May 14, 2019.[6]

III. ADMINISTRATIVE RULEMAKING

As of the date of publication of this chapter, the WOGCC has proposed revisions to its rules governing Applications for Permits to Drill wells ("APDs"). The proposed rule would substantially change the process for protesting APDs by listing criteria that must be proven in support of a protest and in a defense of an APD. The intent of the proposed rule is to reduce the volume of APD protests and contested cases.[7]

IV. CASE LAW

4. Act of July 1, 2019, ch. 187, sec. 1, § 39-13-108(d)(vi), 2019 Wyo. Sess. Laws 531, 531–33 (to be codified at WYO. STAT. ANN. § 39-13-108(d)(vi)).
5. Act of Feb. 15, 2019, ch. 34, 2019 Wyo. Sess. Laws 107, 107–123 (to be codified at WYO. STAT. ANN. §§ 37-5-501 through 37-5-509, 37-5-601 through 37-5-607).
6. *Id*. at § 1(d).
7. . *See* Mark Watson, *Proposed APD Rule Explanation,* WYO. OIL & GAS CONSERVATION COMM'N (July 30, 2019), https://docs.google.com/a/wyo.gov/viewer?a=v&pid=sites&srcid=d3lvLmdvdnxvaWwtYW5kLWdhc3xneDo2NDFiMGU4N2Y0YWE3MzAx [https://perma.cc/5FX7-CT5A].

A. *BTU Western Resources, Inc. v. Berenergy Corporation*

As reported in 2018, in a dispute over the priority of rights between overlapping coal and oil and gas developers in Wyoming's Powder River Basin, the Wyoming Supreme Court determined the United States Bureau of Land Management ("BLM") was a necessary party to proceedings addressing competing federal leases.[8] The Supreme Court remanded the case to the district court to determine whether BLM could be joined as a party. If BLM could not be joined, the Court required dismissal of the case.[9]

Following the Court's ruling in *Berenergy I,* the oil and gas lessee filed a Petition for Rehearing with the Supreme Court, alleging a private oil and gas lease was not addressed in the opinion. The oil and gas lessee alleged the private lease overlapped the federal coal leases held by the coal lessee.[10] The Supreme Court denied the Petition for Rehearing, finding the private lease was not part of the appeal. The Court allowed the district court to address the private lease if the district court found the issue relevant.[11]

On remand, the district court held it did not have jurisdiction "as to the lands underlying the [private] lease absent the presence of the BLM."[12] However, the district court found under law of the case principles that the "accommodation doctrine" applied to direct the order and operation of development, even as to the development of the private lease.[13] The coal lessee appealed the district court's ruling on remand. Specifically, the coal lessee contended the district court could have resolved the private lease issue without the BLM's participation.[14]

Ultimately, the Supreme Court affirmed in part and reversed in part the district court's decision and held: (1) BLM was not a necessary or indispensable party to the private lease dispute; (2) the district court may fully resolve that dispute without the participation

8. Berenergy Corp. v. BTU W. Res., Inc., 2018 WY 2, ¶ 42, 408 P.3d 396, 404 (Wyo. 2018) ("*Berenergy I"*).
9. *Id.* ¶ 43, 408 P.3d at 405.
10. BTU W. Res., Inc. v. Berenergy Corp., 2019 WY 57, ¶¶ 2, 6, 442 P.3d 50, 52–53 (Wyo. 2019) (*"Berenergy II"*).
11. *Id.* at ¶ 2, 442 P.3d at 52.
12. *Id.* at ¶¶ 3 & 10, 442 P.3d at 52-53.
13. *Id.* at ¶ 10, 442 P.3d at 53-54.
14. *Id.* at ¶ 11, 442 P.3d at 54.

of BLM; and (3) the accommodation doctrine applied to the private lease dispute.[15]

B. *Finley Resources, Inc. v. EP Energy E&P Company, L.P.*

Two parties entered into a Purchase and Sale Agreement ("PSA") in December 2007 for the sale of oil and gas leases in the southern portion of Wyoming's Powder River Basin.[16] The plaintiff/purchaser alleged the PSA required the defendant/seller to assign all of its interests under the leases to the plaintiff, without limitations as to the depths and formations addressed by the leases. The plaintiff made several requests for the assignments, but eventually the defendant responded that it retained certain deep rights under the leases.[17]

The plaintiff filed a lawsuit in district court seeking and alleging: (1) quiet title; (2) declaratory judgment; (3) breach of contract by the defendant; (4) breach of implied covenant of good faith and fair dealing by the defendant; and (5) adverse possession. The defendant filed a motion to dismiss based on the PSA's choice-of-law and forum-selection clauses. Following the "Governing Law" provision of the PSA, the district court applied Texas law and granted the defendant's motion to dismiss on the grounds that the claims fell under the PSA's Texas forum-selection clause.[18]

The plaintiff appealed the district court's decision to the Wyoming Supreme Court. The Supreme Court affirmed the district court's dismissal. The Court ruled that all of the plaintiff's claims arose from the PSA, and the forum-selection clause required suit in Texas.[19]

C. *In the Matter of the Appeal of QEP Energy Resources, Inc.*

A taxpayer appealed final decisions of the Wyoming Departments of Revenue and Audit ("Departments") to the Wyoming

15. *Id.* at ¶ 36, 442 P.3d at 60.
16. Finley Res., Inc. v. EP Energy E&P Co., L.P., 2019 WY 65, ¶ 3, 443 P.3d 838, 841 (Wyo. 2019).
17. *Id.* at ¶¶ 3-4, 443 P.3d at 841.
18. *Id.* at ¶¶ 4, 6, 443 P.3d at 841-842.
19. *Id.* at ¶¶ 25-26, 445 P.3d at 847.

State Board of Equalization ("State Board") following a sales and use tax audit for 2015–2017. The Departments had determined the taxpayer was liable for excise taxes on services and materials used at oil and gas well sites. The Department of Revenue also imposed penalties in addition to the excise taxes assessed for the audited tax years.[20]

On appeal to the State Board, the taxpayer contended it was not subject to excise taxes on services performed by vendor/service companies at well sites. Specifically, the taxpayer argued: (1) the Departments improperly attempted to impose a use tax on the services and materials; (2) the current sales tax imposition statute imposed the tax on the vendor/service provider, as opposed to the operator; and (3) penalties imposed by the Department of Revenue should be invalidated.[21]

The State Board agreed with the taxpayer that the use tax did not apply but determined the Departments were authorized to impose the sales tax against the operator under Wyoming's "Special K" sales tax on services and materials used at well sites.[22] The State Board also affirmed the penalties imposed by the Department of Revenue.[23]

20. Findings of Fact, Conclusions of Law, Decision, and Order at ¶ 3, In the Matter of the Appeal of QEP Energy Resources, Inc. Wyo. State Bd. of Equalization (No. 2018-47), http://taxappeals.state.wy.us/images/docket_no_201847.PDF [https://perma.cc/SL77-PS8Z].
21. *Id.*
22. *Id*. at ¶¶ 9 –11, (quoting WYO. STAT. ANN. § 39-15-103(a)(i)(K) (2017)).
23. *Id*. at ¶¶ 24 –26.

A Comparative Analysis of Texas and New Mexico Oil and Gas Laws from a Title Examiner's Perspective

Carly Hewett†

I. Introduction

The statutory framework surrounding oil and gas law and the related title issues in Texas and New Mexico, while similar in many instances, do have some notable differences. New Mexico case law is very limited, which could be due to a variety of reasons, including a smaller state population and the fact that New Mexico and the United States own much of New Mexico's oil and gas productive acreage. Therefore, practitioners often look to other jurisdictions, including Texas, for guidance. Texas's secondary authority is also better developed with its own adopted title standards.[1] New Mexico does not have such guidance. This Article will focus on the distinctions between the oil and gas laws and the passage of title in Texas and New Mexico from a title examiner's perspective. Both states do have a regulatory body—the Texas the Railroad Commission ("TXRRC") and the New Mexico Oil Conservation Division ("NMOCD")[2]—that oversees oil, gas, and other mineral activities by regulating activities such as well spacing, allowables, and pooling. Those regulatory bodies being

II. History

One of the significant differences in examining title in New Mexico is that millions of mineral acres are held by the state and managed by the State Land Commissioner or by the United States and managed by the Bureau of Land Management. The history and the differences in the way Texas and New Mexico became states explains the reason for this discrepancy in mineral ownership.

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1. *See* TEX. PROP. CODE ANN. TIT. 2 APP. (West 2018).
2. *See* TEX. NAT. RES. CODE § 81.052 (West 2018); N.M. STAT. ANN. § 19-1-1 (1978).

In 1846, the New Mexico territory was surrendered to the United States, at which time the land not previously granted by Spain or Mexico and approved by the United States' regulatory framework was transferred to the United States. Subsequently, a variety of land acts, including the Organic Act of 1850, the Ferguson Act of 1898, and the Enabling Act of 1910, allotted sections of land for the public benefit, which land is now held by the State of New Mexico.[3] The result of this is that approximately nine million surface acres and thirteen million subsurface acres of land in thirty-two of New Mexico's thirty-three counties are owned by the State. New Mexico's Commissioner of Public Lands manages all such state trust lands for the benefit of public schools, universities, hospitals, and other public institutions. The United States has retained over four million mineral acres of land in New Mexico, and there are almost 8,000 federal oil and gas leases covering land in the state.[4]

Unlike New Mexico, when Texas was annexed into the United States in 1845, the state maintained all its land. Therefore, Texas does not include any federal lands managed by the Bureau of Land Management. Prior to statehood, the Republic of Texas dedicated fifty-two million acres of land to finance public education, and the Texas State Constitution of 1854 dedicated one-tenth of the public revenue to a perpetual fund for public schools.[5] The intent was that the land be sold with the revenue deposited to the Public School Fund. Presently, the General Land Office is responsible for the management of more than twelve million acres of land dedicated to the Public School Fund, and the land is rarely sold.[6] For the land that was sold, the state did not maintain any mineral interest if sold prior to September 1, 1895. Land sold between 1895 and 1931 was sold subject to the Relinquishment Act, and the state maintained mineral

3. The Organic Act, 9 Stat. 446 (1850); Ferguson Act, 30 Stat. 484 (1898); New Mexico-Arizona Enabling Act of 1910, 36 Stat. 557 (1910).

4. *Oil and Gas Statistics*, U.S. DEPT. INTERIOR BUREAU LAND MGMT. https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics [https://perma.cc/82FQ-HSKA] (Last visited Nov. 3, 2019).

5. *An Overview of the History of Public Education in Texas*, TEX. EDUC. AGENCY https://tea.texas.gov/About_TEA/Welcome_and_Overview/An_Overview_of_the_History_of_Public_Education_in_Texas [https://perma.cc/65A3-ZR35] (last visited Nov. 3, 2019).

6. *The Texas Constitution Of 1876 Set Aside Half of Texas' Remaining Public Lands to Establish a Permanent School Fund (PSF), To Help Finance Public Schools*, TEX. GEN. LAND OFF., http://www.glo.texas.gov/land/land-management/overview/index.html [https://perma.cc/DG2X-3MWB] (last visited Oct. 30, 2019).

ownership with the landowner holding leasing rights, subject to approval from the General Land Office. Lease benefits are shared between the landowner and the state.[7] The Sales Act of 1931 superseded the Relinquishment Act, under which certain land was designated as mineral land. The state retained a non-participating royalty interest in said mineral land. For land sold after June 19, 1983, there is no longer a mineral land classification.

An 1883 Texas law provided for dedicated University Lands, and today approximately two million acres of lands in Texas are leased by the Board for the Lease of University Lands. The state manages these lands for the benefit of the Permanent University Fund, which benefits institutions across the University of Texas and Texas A&M University systems.[8]

III. OWNERSHIP

Ownership of fee interests in both states is similar in that the mineral estate is severable from the surface estate and the mineral estate is dominant. However, New Mexico has enacted a Surface Owners Protection Act that grants rights to private fee landowners and surface tenants. Additionally, the Act outlines procedures that must be followed before an oil and gas lessee can enter the surface of the land for purposes of exploration, drilling, and production.[9] Under the Act, five days' notice must be given for non-surface disturbing activities and thirty days' notice for surface disturbing activities.[10] If the surface owners refuse to enter into an agreement with the lessee, the lessee may still enter the land but must post a bond prior to doing so and beginning operations.[11] Under Texas case law, absent a contractual obligation provided for within the lease, a landowner seeking to recover from the lessee for damages to the surface must prove either specific acts of negligence or that the lessee used more of the land for

7. Originally codified as TEX. REV. CIV. STAT. ANN. art. 5368, the Relinquishment Act is now codified as TEX. NAT. RES. CODE ANN. ch. 52, subch. F (§§ 52.171–.186) (Vernon 1978 and Supp. 1985).

8. *History of Texas Public Lands*, TEX. GEN. LAND OFF. 17 (Mar. 2018), http://www.glo.texas.gov/history/archives/forms/files/history-of-texas-public-lands.pdf [**https://perma.cc/CTN9-J48T**].

9. N.M. STAT. ANN. §§ 70-12-1 to -10 (West 1978).

10. § 70-12-5(A)–(B).

11. § 70-12-6.

oil and gas production than was reasonably necessary.[12] Protection for surface owners has not been codified.

Adverse possession is another issue related to real property ownership that is similar in both states but does have some notable distinctions. Namely, Texas statutes provide for four different periods of continuous possession—being three, five, ten, and twenty-five years—for which different requirements exist to acquire land through adverse possession.[13] New Mexico statutes provide for one ten-year statutory period for adverse possession, but color of title is always a requirement.[14] In both states, government owned land is generally immune from adverse possession actions, and when the surface and minerals have been severed, adverse possession of the surface does not mean adverse possession of the minerals.

IV. OIL AND GAS LEASE

The courts in Texas have adopted the four corners approach when interpreting contracts, including oil and gas leases. Alternatively, New Mexico courts use a contextual approach. For practical purposes, this can be a challenge for practitioners in New Mexico because even if the terms of the document are not ambiguous, the court can still consider circumstantial evidence to determine the intent of the parties.[15] While standard forms are used to lease New Mexico state and federal land and land controlled by the General Land Office in Texas, there is no statutorily required form for fee oil and gas leases in either state.

All oil and gas leases provide for royalties payable on production from the land covered thereby. Both Texas and New Mexico have statutory time periods for the payments of royalties, but they are slightly different. Under the New Mexico Proceeds Payment Act, royalty payments must be made no later than six months after the first day of the month following the date of first sale, and after that, no later than forty-five days after the end of the calendar month in which payment is received by the payor.[16] Late payments will accrue interest, and a Lessor cannot contract this requirement away.[17]

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12. Humble Oil & Ref. Co. v. Williams, 420 S.W.2d 133, 134 (Tex. 1967).
13. TEX. CIV. PRAC. & REM. CODE ANN. §§ 16.024–16.026, 16.028 (2018).
14. N.M. STAT. ANN. § 37-1-22 (2019).
15. C.R. Anthony Co. v. Loretto Mall Partners, 817 P.2d 238, 242–43 (N.M. 1991).
16. N.M. STAT. ANN. § 70-10-3 (2019).
17. First Baptist Church of Roswell v. Yates Petroleum Corp., 345 P.3d 310

Similarly, under the Texas Time for Payment of Proceeds Act, royalty payments must be made no later than 120 days after the first date of sale.[18] If a time for payment is not specified in the lease or other written agreement, subsequent proceeds must be paid sixty days after the end of the calendar month in which oil production is sold. The payment time period is ninety days for gas production.[19] Of course, if there is a reasonable title dispute, royalties can be withheld without interest in both states.

V. Recording and Constructive Notice

To provide notice of a conveyance of an interest in real property, it is necessary in both states to record the conveyancing instrument with the county clerk where the property is located.[20] The notable difference in recording requirements between Texas and New Mexico is due to the existence of New Mexico state and federal lands. Instruments affecting title to federal oil and gas leases must be recorded in the county records where the property is located, as well as with the Bureau of Land Management.[21] The federal records do not impart constructive notice as they are used only for administrative purposes. However, all instruments must be double filed. Instruments affecting title to state of New Mexico oil and gas leases need only be filed with the Commissioner of Public Lands and do not need to be filed twice because the state records do impart constructive notice.[22]

VI. Pooling

Pooling is the consolidation of two or more leases to form a spacing or proration unit and is utilized by operators and allowed by mineral owners to promote geologic, business, and administrative efficiency. Communitization is the same concept but used when state and federal lands are included. Often a tract of land is too small to obtain a well permit, and thus multiple tracts are pooled together to form sufficient acreage to comply with spacing rules.[23] Pooling can

(N.M. 2015).

18. TEX. NAT. RES. CODE ANN. § 91-402 (West 2011).

19. *Id.*

20. N.M. STAT. ANN. § 14-9-1 to -3 (2019); TEX. PROP. CODE ANN. § 13.001 (2014).

21. N.M. STAT. ANN. § 70-1-1 (2019).

22. N.M. STAT. ANN. § 19-10-31 (2019).

23. N.M. STAT. ANN. § 70-2-17 (2019); TEX. NAT. RES. CODE ANN. § 102.011

be voluntary—where all interest owners agree to pool their interests together by delegation, as conveyed in an oil and gas lease—or through a statutorily forced pool.

Both Texas and New Mexico have mechanisms for an oil and gas operator to forcibly pool interests together through their respective state regulatory agencies. The NMOCD can compulsorily pool lands and interests together to form a spacing unit, despite the owner's non-joinder, to avoid the drilling of unnecessary wells and to prevent waste.[24] An operator proposing a well must apply to the NMOCD and have a compulsory pooling hearing. A compulsory pooling order is then issued, which requires drilling within a certain time period. The order also sets out a one-eighth royalty interest to be paid to the compulsory pooled interest owner if the owner does not elect to participate in its share of the costs of drilling the well. In that case, the pooled owner will be carried to payout and not charged drilling costs. The compulsory pooled owner, however, will have to pay a penalty to compensate for the risk of drilling and the lack of paying upfront costs. If the parties are able to come to a voluntary agreement, the one-eighth royalty interest will fall out of the order and the terms of the voluntary agreement will prevail. If an operator fails to obtain a voluntary pooling agreement or a pooling order from the NMOCD, the unpooled interest owner will be entitled to either the interest it would be entitled to if pooling had occurred or the amount it would be entitled to in the absence of pooling, whichever is greater.[25]

The TXRRC, through the authority granted in the Mineral Interest Pooling Act, will pool lands and interests together as a last resort only if fair and reasonable negotiations failed to result in an agreement.[26] The purpose of the Act is to encourage voluntary pooling, to protect correlative rights, and to prevent waste. The Mineral Interest Pooling Act does not cover lands owned by the state or lands that the state has a direct or indirect interest in. Operators have been allowed to use the Mineral Interest Pooling Act to pool small tracts despite opposition, and the mineral owner is granted a one-fifth royalty interest and no risk penalty.[27] Unlike New Mexico, in Texas, an owner of an unleased tract of land can use the Mineral Interest Pooling Act to force its way into a pooled unit if they do not

(West 2019).

24. N.M. STAT. ANN. § 70-2-17 (2019).
25. N.M. STAT. ANN. §70-2-18(B) (2019).
26. TEX. NAT. RES. §§ 102.011, 102.013 (West 2019).
27. TEX. NAT. RES. §§102.001–.018 (West 2019).

receive a fair voluntary pooling offer. This is because in Texas, an unleased owner of a non-drill site tract will not receive a share of production, and the Lessee has no duty to offer them a right to participate in the pooling.

New Mexico has yet to rule on issues related to pooling of overriding royalty and non-participating royalty interests. An overriding royalty interest is carved out of an existing leasehold interest and reduces the working interest owner's net revenue interest. Current Texas case law supports the statement that an overriding royalty owner does not need consent to pool its interest if the underlying lease contains a pooling clause.[28] While New Mexico has not specifically ruled on this topic related to leases of fee mineral interests, we note that New Mexico oil and gas leases and United States oil and gas leases do not include pooling provisions. Interests in state and federal leases must be communitized and approved by the Commissioner of Public Lands or the Bureau of Land Management, respectively. Overriding royalty owners in state and federal leases must first be invited to join the communitized unit. If the owner does not consent, a compulsory pooling application must evidence the "reasonable effort" made to obtain consent.[29]

A non-participating royalty interest is carved out of the mineral interest and reduces the mineral interest owner's royalty interest. Under Texas case law, a ratification of the pooling provision of an oil and gas lease is required to pool an owner of a non-participating royalty interest.[30] New Mexico has not ruled on this issue, but practitioners often assume Texas law would be followed. It is important to note that conveyances of overriding royalty interests or non-participating royalty interests can include provisions specifically stating that consent is not required to pool the interest being conveyed, in which case the language in the document creating the interest would rule.

VII. MARITAL PROPERTY

Both Texas and New Mexico are community property states and define community property as being all property acquired during

28. Union Pac. Res. Co. v. Hutchison, 990 S.W.2d 368, 371 (Tex. App.—Austin, 1999, pet. denied).
29. 43 C.F.R. § 3181.3 (2019).
30. Brown v. Smith, 174 S.W.2d 43, 46–47 (1943).

marriage that is not separate property.[31] Separate property is generally property acquired by gift, devise, bequest, or descent, or designated as separate property in a writing signed by both spouses or by court judgment.[32] However, there are a few minor distinctions related to the treatment of marital property between Texas and New Mexico. For example, in New Mexico, property acquired by a woman prior to July 1, 1973 through an instrument in writing in her name alone was presumed to be her separate property.[33] Additionally, while Texas has accepted common law marriage, in New Mexico, common law marriage cannot establish rights in property.[34] A more significant difference in the treatment of marital property between the two states is that Texas recognizes sole management community property, meaning that if property is conveyed to one spouse, that spouse is able to exercise sole management, control, and disposition of that property during the marriage, assuming both spouses are still living.[35] In New Mexico, both spouses must join in any transfer, conveyance, or mortgage of any community property, and if they do not join, that conveyance is void and has no effect.[36] However, it can be later validated by a ratification in writing from the other spouse.[37]

VIII. DESCENT AND DISTRIBUTION

The laws of the state where property is located is determinative to pass property upon the owner's death, even if the decedent was domiciled in a different state.[38] Both the laws of intestacy, meaning property passing under the state's laws in the absence of a will, and the requirements for probating an estate, with or without a will, have some notable distinctions between New Mexico and Texas. The differences start by recognizing that New Mexico has adopted the Uniform Probate Code, while Texas has its own Estates Code.[39]

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31. N.M. STAT. ANN. § 40-3-8(B) (2019); TEX. FAM. CODE ANN. §3.002 (West 2019).
32. N.M. STAT. ANN. § 40-3-8(A) (1978); TEX. FAM. CODE §3.001 (West 2019).
33. N.M. STAT. ANN. § 40-3-12(B) (1978).
34. TEX. FAM. CODE § 2.401 (West 2019); In re Gabaldon's Estate, 34 P.2d 672, 674–75 (N.M. 1934).
35. TEX. FAM. CODE § 3.102 (West 2019).
36. N.M. STAT. ANN. § 40-3-13 (1978).
37. N.M. STAT. ANN. § 40-3-13(B) (1978).
38. Robby Alden, *Modernizing the Situs Rule for Real Property Conflicts*, 65 TEX. L. REV. 585 (1987).
39. N.M. STAT. ANN § 45-1-301 (2019); *See generally* TEX. EST. CODE. ANN. (West 2015).

For purposes of comparing the laws of intestacy, we will focus on the passage of title upon the death of a married person with children. July 1, 1959 is an important date when discussing New Mexico's laws of descent and distribution. Prior to this date, if the wife died, all her community property interest would automatically pass to her husband. Additionally, until July 1, 1973, the wife did not have testamentary authority to devise community property. However, upon the husband's death, five-eighths of the total community property interest would pass to the wife through intestacy and three-eighths would pass to the children. Since July 1, 1959, when a person dies without a will, all community property passes 100% to their spouse. Further, from June 12, 1959 until July 1, 1973, if a husband died intestate, all community property passed to his wife without the necessity to probate his estate. This is one of the few exceptions to the requirement of an estate administration in New Mexico.

In Texas, before September 1, 1993, upon the death of one spouse, the surviving spouse only retained their one-half community property interest, while the decedent's one-half was divided equally among the children.[40] Since September 1, 1993, upon the death of one spouse without a will, the entire community property estate passes to the surviving spouse. Therefore, today, the passage of community property through intestacy is treated the same in both states.[41] Separate property in New Mexico passes one-fourth to the surviving spouse and three-fourths to the children through intestate succession. Separate property in Texas passes two-thirds in fee simple to the children and one-third to the children, subject to a life estate in the surviving spouse.[42]

When determining the share attributable to each heir through intestacy, from statehood until June 1, 1993, New Mexico distributed shares per stirpes, which is the method that Texas still uses today. This means that the estate is divided into as many shares as there are heirs in the nearest degree of kinship and deceased persons in that same degree who left surviving issue. Each generation is treated by the root and there is no combination of second-degree kin. Since June 1, 1993, New Mexico distributes intestate shares by representation, which means that the same method determines the number of shares but distributed per capita with the combination of second-degree kin.

40. TEX. PROB. CODE § 45 (West 2019); TEX. PROB. CODE § 38(b)(1) (West 2019).

41. TEX. EST. CODE ANN. §§ 201.002(b), .003(b)(2) (West 2020).

42. § 201.002(b).

In the absence of a will, Affidavits of Heirship, including facts surrounding the death and legal heirs, are often filed in the county where a decedent's real property is located. Affidavits of Heirship are not sufficient to pass marketable title in New Mexico. However, in practice, many operators will rely on Affidavits of Heirship to release funds due to mineral owners for small interests. In Texas, if an Affidavit of Heirship has been filed of record for more than five years and was executed by two disinterested parties, it is received by the court as prima facie evidence of the facts contained therein.[43]

With or without the existence of a will, the laws surrounding the administration of decedents' estates also differ between Texas and New Mexico. In New Mexico, a probate proceeding is required for title to be considered marketable.[44] In both states, a will is not effective to pass title until it is admitted to probate, and the passage of title relates back to the date of death. However, a major difference is that if real property is located within the state of New Mexico, an in-state administration of the estate is required. This is true even if the estate was already administered in a different state and can be done via an original or concurrent probate with the proceedings in the decedent's domiciliary state, an ancillary probate proceeding, or a short form proceeding.[45] Further, personal representatives are required to execute a distribution deed to evidence the passage of title from the estate.[46] While Texas code provides for similar proceedings for the estates of out of state decedents, they are less often utilized because an exemplified copy of a foreign will, along with a copy of the judgment, order, or decree, can be filed and recorded in any Texas county in which decedent's land is located without the necessity of conducting probate proceedings in a Texas court.[47] Therefore, a recorded foreign will in Texas has the same effect as a domestic will and provides constructive notice of the transfer of real property.[48]

There are specific vehicles in both states to pass title without the necessity of probate. For example, parties can own property as joint tenants with right of survivorship, which would immediately vest

43. TEX. EST. CODE ANN. § 203.001 (West 2019).; TEX. PROP. CODE ANN. TIT. 2—APP. TEXAS TITLE EXAMINATION STANDARD 11.70; N.M. STAT. ANN. § 45-1-302 (2019).

44. N.M. STAT. ANN. § 45-1-302 (2019).

45. N.M. STAT. ANN. §§ 45-3-201, 308; 45-4-204, 207 (2019).

46. N.M. STAT. ANN. § 45-3-907–908 (2019).

47. TEX. EST. CODE ANN. § 503.001 (West 2020).

48. *Id.*

title in the surviving joint tenant upon the death of one tenant.[49] In Texas, joint tenancy between married persons was difficult to establish prior to 1987, at which time the Texas Constitution was amended to say, "[s]pouses may agree in writing that all or part of their community property becomes the property of the surviving spouse on the death of a spouse."[50] However, in both states, joint tenancy between spouses or a spouse and a third party does not destroy the presumption of community property. Transfer on death deeds are another method to provide for the non-probate passage of title.[51] The New Mexico code also allows married persons to transfer title to their homestead by affidavit, while in Texas, a probate is not required for community property to pass to the surviving spouse when a spouse dies intestate.[52] A small estate affidavit can be utilized to pass title in Texas for estates valued at less than $75,000.[53]

IX. CONCLUSION

This Article is intended to only highlight a few basic differences between Texas and New Mexico oil and gas law from a title examiner's perspective. One could write an entire paper on the many distinctions discussed herein. In today's energy industry, significant exploration and operation of oil and gas occurs in New Mexico and Texas. Accordingly, it is common for professionals to crossover between the two states, which makes awareness of the differences essential.

49. Swink v. Fingado, 850 P.2d 978 (N.M. 1993).
50. TEX. CONST. art. XVI, § 15.
51. N.M. STAT. ANN. § 45-6-401 (2019); TEX. EST. CODE ANN. § 114.05 (West 2020).
52. N.M. STAT. ANN. § 45-1-1205 (2019); TEX. EST. CODE ANN. § 453.002 (West 2020).
53. TEX. EST. CODE ANN. § 205.001 (West 2020).

COME AND CHARGE IT: THE RISE OF UTILITY-SCALE BATTERY ENERGY STORAGE IN TEXAS

Matthew A. Arth[1]

Affordable, reliable battery energy storage has long been the holy grail of the electric grid. From avoiding expensive transmission build-out to smoothing out fluctuations inherent to wind and solar resource output, batteries hold the promise of providing the solution to an ever more intermittent and distributed grid. Across the United States and particularly in Texas, that futuristic vision is beginning to approach reality as battery costs decline[2] and favorable regulatory policy is implemented.[3] This Article addresses the current state of battery energy storage system development and notes recent contributory policy developments at both the national and state level.

I. BY THE NUMBERS

According to the United States Energy Information Administration ("EIA"), as of March 2019, the United States had 899 megawatts ("MW") of operating utility-scale battery storage power capacity[4] and over 1,236 megawatt hours ("MWh") of battery energy capacity.[5] This installed capacity represents a nearly fourfold increase

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2. *See* RAN FU, TIMOTHY REMO & ROBERT MARGOLIS, NAT'L RENEWABLE ENERGY LAB., 2018 U.S. UTILITY-SCALE PHOTOVOLTAICS-PLUS-ENERGY STORAGE SYSTEM COSTS BENCHMARK iii-iv (2018).

3. *See* Peter Kelly-Detwiler, *Batteries About to Come to Texas in a Big Way*, TEX. RENEWABLE ENERGY INDUSTRIES ALLIANCE (Nov. 4, 2019), https://www.treia.org/news/2019/11/4/batteries-about-to-come-to-texas-in-a-big-way [https://perma.cc/MCS7-QW74].

4. Patricia Hutchins, *U.S. Utility-Scale Battery Storage Power Capacity to Grow Substantially by 2023*, U.S. ENERGY INFO. ADMIN. (July 10, 2019), https://www.eia.gov/todayinenergy/detail.php?id=40072 [https://perma.cc/8EDB-PJUN]. *See generally* LOLA INFANTE & OLGA CHISTYAKOVA, EDISON ELEC. INST., LEADING THE WAY: U.S. ELECTRIC COMPANY INVESTMENT AND INNOVATION IN ENERGY STORAGE (2018) (presenting case studies of a variety of battery storage projects developed in the United States).

5. Vikram Linga, *Most Utility-Scale Batteries in the United States are Made of Lithium Ion*, U.S. ENERGY INFO. ADMIN. (Oct. 30, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41813 [https://perma.cc/Q2FL-9L2X].

since 2014 and the EIA projects this to continue climbing to over 2,500 MW nationally by 2023.[6] In 2019 alone, the grid-based energy storage market appears likely to have nearly double from the previous year.[7] There are several varieties of energy storage, from molten-salt thermal storage to batteries containing zinc or nickel, but lithium-ion batteries predominate in utility-scale deployment.[8] The United States Department of Energy ("DoE") attributes the popularity of lithium-ion batteries to their comparatively high storage capacity, small footprint, and ready availability.[9] Of the independent system operators ("ISO") and regional transmission organizations ("RTO"), PJM has the highest installed capacity for utility-scale batteries followed by CAISO.[10] For context, the largest battery storage systems currently operating in the United States are two forty MW systems in Alaska and California respectively.[11] However, the median project capacity for a utility-scale battery has been closer to ten MW[12] with an average duration of 1.7 MWh.[13] Significantly larger storage projects are now in the preliminary stages of development, with companies such as solar developer Intersect Power proposing to construct 495 MW of battery storage alongside a 495 MW solar installation in Borden County, Texas.[14]

Among the states, Texas has the third most operating utility-scale battery storage, with about half the installed capacity as

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6. Hutchins, *supra* note 4.

7. Christian Roselund, *US Energy Storage Market Set to Almost Double this Year*, PV MAG. (May 22, 2019), https://www.pv-magazine.com/2019/05/22/us-energy-storage-market-set-to-almost-double-this-year/ [https://perma.cc/P8T7-Z4NT].

8. *Solar-Plus Storage 101*, OFF. OF ENERGY EFFICIENCY AND RENEWABLE ENERGY (Mar. 11, 2019), https://www.energy.gov/eere/solar/articles/solar-plus-storage-101 [https://perma.cc/S28Q-MFDD]. Aside from batteries and thermal energy storage, other types of energy storage include compressed air, flywheels, and, most significantly, pumped hydroelectric, which as of March 2018 accounts for more than 90% of energy storage capacity in the United States. *See About Electricity Storage*, EPA, https://www.epa.gov/energy/electricity-storage [https://perma.cc/97VQ-Z36Z] (last visited Dec. 16, 2019).

9. *Id.*

10. ALEXANDRA ZABLOCKI, ENVTL. AND ENERGY STUDY INST., FACT SHEET: ENERGY STORAGE FEBRUARY 2019 (2019).

11. Hutchins, *supra* note 4.

12. FU ET AL., *supra* note 2, at 6.

13. OFF. OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, *supra* note 8.

14. *See* Iulia Gheorghiu, *Developer Eyes World's Largest Solar+Storage Facility for Texas*, UTIL. DIVE (Feb. 19, 2019), https://www.utilitydive.com/news/developer-eyes-worlds-largest-solarstorage-facility-for-texas/548691/ [https://perma.cc/774W-G3W2].

California and slightly trailing Illinois.[15] In January 2019, the Electric Reliability Council of Texas ("ERCOT") reported that Texas's main power region has over eighty-nine MW of utility-scale battery resources installed, with an additional 2,300 MW of new battery capacity under study.[16] The *Houston Chronicle* subsequently reported that storage's generating capacity in Texas is expected to reach 360 MW in 2020 and that ERCOT has over 7,200 MW of large-scale battery storage in various stages of development for the next five years.[17] These battery resources are predominantly used to supply ancillary services,[18] although Texas is beginning to see battery systems installed for use in energy purchases and sale arbitrage in ERCOT's wholesale energy market.[19] In earlier stages of battery development, studies showed that benefit stacking, i.e. obtaining multiple value streams from a battery, including energy price arbitrage and capacity payments in addition to supplying ancillary services, was necessary to justify the high cost of investment in battery storage capacity.[20] Although benefit stacking is slowly becoming more commonplace, the declining costs of batteries and the availability of federal Investment Tax Credits ("ITC") for combined storage and solar projects are the primary causes of the recent dramatic increase in battery storage development.[21]

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15. Hutchins, *supra* note 4.

16. *Growth of Energy Storage Resources in the ERCOT Region*, ERCOT (Jan. 2019), http://www.ercot.com/content/wcm/lists/164134/Storage_One_Pager_FINAL.pdf [**https://perma.cc/P85Y-LGZF**].

17. L.M. Sixel, *Battery Storage on the Verge of Changing Texas Power Grid*, HOUSTON CHRONICLE (Dec. 19, 2019).

18. *Id.*

19. For instance, Vistra Energy subsidiary Luminant will be using its new 42 MWh system at the Upton 2 solar facility in west Texas for energy arbitrage. *See e.g.,* Andy Colthorpe, *Tough Texas Market Conditions Defied as 42MWh Battery System Comes Online*, ENERGY STORAGE NEWS (Jan. 7, 2019), https://www.energy-storage.news/news/tough-texas-market-conditions-defied-as-42mwh-battery-system-comes-online [**https://perma.cc/RCV5-XTJN**].

20. *See e.g.* Judy Chang et al., *The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments*, THE BRATTLE GROUP 1, 17 (Nov. 2014), https://brattlefiles.blob.core.windows.net/system/news/pdfs/000/000/749/original/the_value_of_distributed_electricity_storage_in_texas.pdf [**https://perma.cc/2LBC-R2G2**].

21. *Growth of Energy Storage Resources in the ERCOT Region*, ERCOT (Jan. 2019), http://www.ercot.com/content/wcm/lists/164134/Storage_One_Pager_FINAL.pdf [**https://perma.cc/P85Y-LGZF**]. *See generally* Stephen Comello & Stefan Reichelstein, *The Emergence of Cost Effective Battery Storage*, 10:2038 NATURE

The ITC is available to battery systems that are charged by a renewable energy resource at least 75% of the time and currently allows for a 26% tax deduction for projects starting construction in 2020.[22] However, this credit is being phased-down and is scheduled to decrease to 22% in 2021 and 10% from 2022 onwards for commercial systems.[23] The Environmental and Energy Study Institute ("EESI") notes that the price of lithium-ion batteries in electric vehicles, similar to the technology used in energy storage, has declined by 73% from 2010 to 2016 and has contributed to falling energy storage costs on the grid.[24] DoE estimates that the cost of a sixty MW storage system ranges from approximately $380 per kWh for systems that provide four hours of electricity to $895 per kWh for thirty-minute systems.[25] Projects that combine solar and storage are increasingly prominent, and costs of a storage system for such projects vary based on whether the photovoltaic and battery systems are at different sites or are co-located.[26] Furthermore, and by way of comparison, a solar-plus-storage project that offered a median energy price of $45 per MWh in 2017 is now competing with a similar solar-plus-storage project that came online in 2019 offering a median energy price of $36 per MWh.[27] Together, the declining costs of lithium-ion batteries and the availability of favorable tax policies appear primed to continue to accelerate utility-scale battery energy storage development in Texas.[28]

II. RECENT POLICY DEVELOPMENTS

COMMS., 1, 6 (2019), https://www.nature.com/articles/s41467-019-09988-z.pdf [**https://perma.cc/GH5P-2SWQ**].

22. Emma Elgqvist, Kate Anderson & Edward Settle*, Federal Tax Incentives for Energy Storage Systems*, NAT. RENEWABLE ENERGY LAB. (Jan. 2018), https://www.nrel.gov/docs/fy18osti/70384.pdf [**https://perma.cc/R549-YY3J**].

23. *See Business Energy Investment Tax Credit (ITC),* DSIREUSA.ORG (Mar. 1, 2018) https://programs.dsireusa.org/system/program/detail/658 [**https://perma.cc/EAG6-RFBR**].

24. ZABLOCKI, *supra* note 10, at 2..

25. OFF. OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, *supra* note 8.

26. *Id.*

27. Jason Deign, *Xcel Attracts 'Unprecedented' Low Prices for Solar and Wind Paired With Storage*, GREENTECHMEDIA.COM (Jan. 8, 2018), https://www.greentechmedia.com/articles/read/record-low-solar-plus-storage-price-in-xcel-solicitation [**https://perma.cc/922D-JC3D**].

28. *See generally e.g.,* Mark Watson, *Solar-Plus-Storage Likely the 'Next Big Thing' in ERCOT: Expert*, S&P GLOBAL (Oct. 22, 2018), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/102218-solar-plus-storage-likely-the-next-big-thing-in-ercot-expert [**https://perma.cc/8GN7-7H6A**].

A significant driver of the increase in battery storage installations are changes to the regulatory environment, both nationally and at the state level, which are encouraging further development. At the national level, the Federal Energy Regulatory Commission ("FERC") issued Order No. 841 in February 2018 requiring ISOs and RTOs to revise their tariffs to remove barriers to entry in order for battery energy storage to better compete with other generation sources in wholesale energy, capacity, and ancillary services markets.[29] Key regulatory changes include ensuring that battery storage resources are eligible to provide all services that they are technically capable of offering and adjusting market rules to accommodate storage-specific attributes, such as bidding parameters that account for state-of-charge and allowing batteries to operate as both supply *and* demand resources.[30] In December 2018, the Energy Storage Association released its analysis of each ISO's and RTO's level of compliance with FERC Order No. 841.[31] It found that CAISO has largely implemented the market revisions required by the Order but that no other ISOs or RTOs had yet achieved full compliance and that further time for implementation would likely be necessary.[32] Texas's electric industry is regulated by the Public Utility Commission of Texas ("PUCT") largely independently of FERC. While FERC Order No. 841 generally does not apply in Texas, ERCOT and Texas market participants are monitoring such developments closely.[33] For instance, ERCOT has established the Battery Energy Storage Task Force to develop policy recommendations for consideration by the ERCOT Technical

29. *See generally Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 F.E.R.C. ¶ 61,127 (2018).

30. Brian Orion & Sarah Kozal, *Five Key Takeaways from FERC's Recent Energy Storage Order*, POWER MAGAZINE (June 1, 2018) https://www.powermag.com/5-key-takeaways-from-fercs-recent-energy-storage-order/ [**https://perma.cc/5TJ5-TPGK**].

31. *Energy Storage Association Unveils Initial Assessment of Regional Grid Operator Compliance with Federal Regulatory Energy Commission's Order 841*, ENERGY STORAGE ASS'N (Dec. 11, 2018) https://energystorage.org/energy-storage-association-unveils-initial-assessment-of-regional-grid-operator-compliance-with-federal-energy-regulatory-commission-order-841/ [https://perma.cc/5XG6-HFAQ].

32. *Id.*

33. *Growth of Energy Storage Resources in the ERCOT Region*, ERCOT (Jan. 2019), http://www.ercot.com/content/wcm/lists/164134/Storage_One_Pager_FINAL.pdf [**https://perma.cc/P85Y-LGZF**].

Advisory Committee on operational and market design policies to better integrate battery storage resources into the market.[34]

In February 2018, the PUCT opened rulemaking proceeding Project No. 48023 to gather feedback from industry stakeholders to determine if regulatory changes are necessary to accommodate front-of-meter ("FTM") battery storage development and other non-traditional electric technologies.[35] This rulemaking was initiated following the dismissal of the transmission and distribution service provider ("TDSP") AEP's previous application in PUCT Docket No. 46368 to own and install a battery in a remote part of its service area in lieu of a more traditional distribution "wires" solution.[36] Pursuant to Public Utility Regulatory Act § 35.152, in Texas, battery storage is largely considered a generation resource.[37] Although batteries share characteristics with both generation and transmission/distribution, this legal designation as generation was implemented to maintain the distinction between types of market participants. In areas within ERCOT open to competition, transmission and distribution utilities are statutorily prohibited from owning generation resources.[38] In its application,[39] AEP noted that the specific wording of PURA § 35.152(a) states, "Electric energy storage equipment or facilities *that are intended* to be used to sell energy or ancillary services at wholesale are generation assets."[40] AEP argued that the battery at issue would not fall within Section 35.152(a)'s definition of generation because the battery would be used solely for reliability purposes as distribution equipment and not for the purchase or sale of energy or ancillary services.[41] However, other market participants raised concerns about

34. *See Battery Energy Storage Task Force*, ERCOT http://www.ercot.com/committee/bestf [https://perma.cc/8YL3-SS6A].

35. *Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service,* Project No. 48023 (pending), PUB. UTIL. COMM'N TEX. (2018). Disclosure: the author represented Commission Staff in Project No. 48023 during his employment by the PUCT. No information beyond that which is publicly available is presented in this article.

36. *See generally Application of AEP Texas North Company for Regulatory Approvals Related to the Installation of Utility-scale Battery Facilities*, Docket No. 46368, PUB. UTIL. COMM'N TEX. (Feb. 15, 2018) (dismissing the proceeding and ordering that a rulemaking be opened to address the issues raised).

37. *See* PURA §§ 35.151–35.152 (2019).

38. *See* PURA §§ 31.002(6), 31.002(10), 39.105(a) (2019).

39. *Application of AEP Texas North Company for Regulatory Approvals Related to the Installation of Utility-scale Battery Facilities*, Docket No. 46368, Application at 4, PUB. UTIL. COMM'N TEX. (Sept. 16, 2016).

40. *Id.*

41. *Application of AEP Texas North Company for Regulatory Approvals Related*

the potential for distortion of market prices should ownership of batteries by transmission and distribution service providers become widespread.[42] Rather than make such a sweeping determination in the context of a contested case, the PUCT determined that the rulemaking process would better allow for consideration of the broad market implications involved and allow for greater stakeholder participation.[43]

In Project No. 48023, Commission Staff published thirteen Questions for Comment and received sixty-three comments and replies from a wide variety of industry stakeholders.[44] Comments addressed whether the Public Utility Regulatory Act allows an ERCOT TDSP to own a battery storage device, how energy inflows and outflows should be accounted for, potential battery ownership models, and regulatory approval processes in the event of TDSP ownership, such as an adapted certificate of convenience and necessity process.[45] In addition to AEP's grandfathered four MW Presidio battery,[46] Texas's largest utility, Oncor, noted that it operates five twenty-five kW batteries on its distribution grid in Dallas to study the effects of battery performance.[47] After meeting with stakeholders and reviewing these comments, the Commission announced at its Open Meeting on January 25, 2019, that it would put Project No. 48023 on hiatus during Texas's 86th Legislative Session.[48] Following the end

to the Installation of Utility-scale Battery Facilities, Docket No. 46368, Applicant AEP Texas' Initial Brief at 9–12, PUB. UTIL. COMM'N TEX. (July 7, 2017).

42. *See e.g. Application of AEP Texas North Company for Regulatory Approvals Related to the Installation of Utility-scale Battery Facilities*, Docket No. 46368, Joint Motion for Summary Decision of Luminant Energy Company LLC, TXU Energy Retail Company LLC, Alliance for Retail Markets, NRG Companies, Texas Energy Association for Marketers, Calpine Corporation, Texas Competitive Power Advocates, Texas Industrial Energy Consumers, and the Office of Public Utility Counsel, PUB. UTIL. COMM'N TEX. (Mar. 31, 2017) (disagreeing with AEP's positions and requesting that AEP's application be denied).

43. *See Application of AEP Texas North Company for Regulatory Approvals Related to the Installation of Utility-scale Battery Facilities*, Docket No. 46368, Order at 2–5, PUB. UTIL. COMM'N TEX. (Feb. 15, 2018).

44. *See Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service,* Project No. 48023, Commission Staff's Memorandum, PUB. UTIL. COMM'N TEX. (Jan. 10, 2019) (summarizing comments).

45. *Id.*

46. *Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service,* Project No. 48023, Initial Comments of AEP Texas and ETT at 14, PUB. UTIL. COMM'N TEX. (Nov. 2, 2018).

47. *Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service,* Project No. 48023, Oncor Electric Delivery Company LLC's Response to Questions at 11–12, PUB. UTIL. COMM'N TEX. (Nov. 2, 2018).

48. *See Rulemaking to Address the Use of Non-Traditional Technologies in*

of the legislative session, the PUCT is anticipated to resume consideration of potential rulemaking changes in Project No. 48023.

During the legislative session, several statutory changes related to battery storage were proposed or adopted. For instance, Senate Bill No. 1012 amended PURA § 35.152 to clarify that electric cooperatives and municipally-owned utilities may own batteries without registering as power generation companies.[49] Perhaps the most intriguing was Senate Bill No. 1941,[50] which closely tracked the proposal from the comments filed by Texas Advanced Energy Business Alliance ("TAEBA") in Project No. 48023.[51] SB1941 would have permitted a TDSP to contract with a PGC, following approval by the PUCT, to receive energy from a battery for the purpose of ensuring reliable service to the TDSP's distribution customers.[52] The bill would not have allowed a TDSP to own the battery outright, but would permit the PUCT to authorize a contract for services if the TDSP's contract for use of the battery "is more cost-effective than construction or modification of traditional distribution facilities."[53] In order to incentivize TDSPs to make use of this potentially more cost-effective option, SB1941 would have allowed the TDSP to earn a "reasonable return" on such contracts.[54] The session expired before SB1941 could be adopted, but the near passage of this contract-for-battery-service model gives some indication of the Texas Legislature's direction on battery storage ownership and may influence the PUCT's direction if and when Project No. 48023 is resumed.[55]

Electric Delivery Service, Project No. 48023, Commission Staff's Memorandum, PUB. UTIL. COMM'N TEX. (Jan. 10, 2019) (summarizing comments).

49. TEX. S.B. 1012, 86th Leg., R.S. (2019) (adding Subsection (d) to PURA § 35.152); *see also* HJ Mai, *Texas Utilities Poised to Get Ability to Own Energy Storage Assets*, UTIL. DIVE (Aug. 13, 2019) https://www.utilitydive.com/news/texas-utilities-poised-to-get-new-ability-to-own-energy-storage-assets/560797/ [https://perma.cc/4DLR-LJKB].

50. TEX. S.B. 1941, 86th Leg., R.S. (2019).

51. *See generally Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service,* Project No. 48023, Comments of Texas Advanced Energy Business Alliance, PUB. UTIL. COMM'N TEX. (Nov. 2, 2018).

52. TEX. S.B. 1941, 86th Leg., R.S. (2019).

53. *Id.*

54. *Id.*

55. *See* Suzanne Bertin, *In Texas, Incentives for Wind and Solar Development Were Extended, but Storage Questions Go Back to PUCT*, ADVANCED ENERGY ECON. (June 5, 2019) (discussing SB1941 and anticipated influence on Project No. 48023) https://blog.aee.net/in-texas-incentives-for-wind-solar-development-were-extended-but-storage-questions-go-back-to-puct [https://perma.cc/PEP6-KUXB].

III. CONCLUSION

While utility-scale battery storage development has increased steadily in Texas for the past several years, the coalescing of favorable statutory and regulatory changes alongside declining battery costs appear likely to supercharge batteries installed capacity in the Lone Star State. The hybrid nature of battery technology has raised questions that are unique to ERCOT about energy storage's place in the market, but as regulators and legislators develop policy about battery ownership models, further deployment will inevitably increase.

EXPERIENCE IS A DEAR TEACHER—THE TEXAS WIND DECOMMISSIONING STATUTE

Rod Wetsel

"*Experience is a dear teacher, but fools will learn at no other*" - Benjamin Franklin

I. INTRODUCTION – A NEW PROBLEM

As is well known among both my students and colleagues, my professional life as a lawyer (and later as a law professor) took a monumental turn in 1999 when I reviewed and drafted my first wind lease in Nolan County, Texas.[1] That lease, as well as all of the other wind leases at the time, contained contractional "clean up and restoration" clauses similar to many oil and gas leases then in use. Simply put, the leases provided that upon expiration or termination of the lease (which for a wind lease, unlike an oil and gas lease, might be fifty or more years in the future), the lessee would remove its equipment and restore the surface "to as near as reasonably possible to its original condition" prior to the lease.[2]

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2. I would like to acknowledge the assistance and participation of my former outstanding student and now associate, Laura Bowen, in the research and writing of this article. Without her timeless loyalty and dedication both to me and the field of

Of course, the overlooked issue was the huge difference between wind and oil and gas leases in the work and cost required to remove wind turbines weighing hundreds of tons, along with millions of pounds of concrete, underground and overhead lines, and large access roads as opposed to a few well locations, pump jacks, pipes, and tank batteries. Not surprisingly, before long, Texas landowners (and Texas lawyers) began to recognize the enormity of this problem for future generations. Texas lands have long been haunted by the "boom and bust" cycles of the Texas oil industry with insolvent operators failing to clean up their leases, leaving the landscape cluttered with weed-infested well sites, unused pipe, rusting pump jacks and tank batteries. Clearly, Texas landowners did not want to repeat the experience on a gargantuan scale.

In response, Texas lawyers, like myself, began to develop the concept of a "removal bond" to provide the necessary clean up funds in the far-distant future. As originally conceived, the "removal bond" provision (or decommissioning clause as it would become known), outlined a process in which the wind company was required to put up a bond ten to fifteen years after the project began operation, amounting to the cost of removal of the equipment and restoration of the property, less the salvage value. With the wind boom, leases evolved so that later clauses shortened the time for posting the bond to a maximum of ten years and eliminated the ability to deduct salvage value. So, over the years, the removal bond clause became a standard provision in Texas wind leases (although with sometimes different wording). During the same time, many states passed "Decommissioning Statutes," but Texas did not.[3]

In early 2018, I received a call from Curtis Smith, the Chief of Staff for State Representative Terry Canales of District 40 in South Texas, asking if I would help draft a decommissioning bill. Initially I was reluctant but eventually decided that if someone had to do it, perhaps I should, so that landowners in Texas could have a voice in the creation of such a law.

No doubt, in the years before 2018, Texas legislators were hesitant to regulate wind as the wildly successful new industry in Texas was considered largely successful because it was without

energy law, neither this article or this Texas decommissioning statute would have been written.

3. Elizabeth A. Weis, *Wind Energy Legislation Strategies for the Lone Star State*, 10 INQUIRIES J., no. 05, 2018, http://www.inquiriesjournal.com/a?id=1738 [https://perma.cc/KY7N-64W6].

regulation.[4] The only other existing statute regulating wind was not passed until 2017. It was a controversial bill from Senator Donna Campbell, S.B. 277, which prohibited the granting of wind project tax valuation limitation agreement for school districts within 28.7 miles of a military aviation facility.[5]

Therefore, in April 2018, I testified before the Energy Resources Committee of the Texas House of Representatives. At the hearing, a legion of wind lobbyists met me, urging me not to "open the flood gates for the regulation of the wind industry in Texas." In an effort to work with my wind counterparts, I told the committee that since removal bond clauses were found in almost all, if not all, Texas leases, a statute was probably unnecessary. However, the committee remained unconvinced.

As a result, the idea of a Texas Wind Decommissioning statute was born. After much drafting and compromise with wind companies and opponents alike, H.B. 2845 passed both houses of the Texas legislature and became law on September 1, 2019.[6]

II. SHOW ME THE NUMBERS

To best understand why the legislature pushed for a mandatory decommissioning clause, it is important to understand the logistics of removing a wind farm from the land. At the end of a wind turbine's useful life, which is typically twenty to thirty years, the turbine must either be repowered or decommissioned.[7] Repowering typically requires replacing the nacelle and blades while preserving the original tower, a process required as frequently as every ten years, depending on the pace of technology improvement. Decommissioning a wind turbine calls for the removal of everything above and below the ground, including the concrete footing buried around the turbine.[8]

When a turbine is completely decommissioned, all components of the turbine are cut into pieces for transportation and

4. *Id.*
5. TEX. TAX CODE ANN. § 312.0021 (West Supp. 2018).
6. H.B. 2845, 86th Leg., R.S. (2019). Full text of the bill is available at https://capitol.texas.gov/tlodocs/86R/billtext/html/HB02845I.htm.
7. *Decommissioning*, APEX CLEAN ENERGY, https://www.cottonplainswind.com/decommissioning (last visited Nov. 1, 2019), [https://perma.cc/PKGR-46YN].
8. Kalina Oroschakoff, *Small old wind towers make for big new problems*, POLITICO (Feb. 23, 2018), https://www.politico.eu/article/small-old-wind-towers-make-for-big-new-problems/, [https://perma.cc/PU94-STR4].

stored until such time as valuable components such as copper can be extracted and resold. There is no industry standard for recycling other parts of the turbines, causing some panic as to where the industrial waste will go once decommissioned. While many of the parts of a turbine are recyclable, the fiber glass composite blades had no successful use until very recently.

As a result, the blades were often buried in landfills. The actual scrap value of decommissioned turbine components is unknown, making the valuation of decommissioning difficult. Scrap value depends largely on the secondary market for recycled parts. No such market currently exists, so the "salvage value" language in HB 2845 is speculative at best.[9] From the beginning, I expressed concern over the salvage value subtraction, as a dip in the value of copper could result in an undervalued bond leaving the landowner to rely on revaluation of the bond every five years.

Again, the costs associated with dismantling a turbine are largely unknown. So far in Texas, only two wind farms have been decommissioned. Since both were decommissioned at the expense of the wind energy company, the costs associated with the decommissioning were not publicized. One estimate valued the removal cost as high as $200,000 per turbine, making the total cost of decommissioning the over 13,000 turbines in Texas approximately $2.3 billion.[10]

Of the few other decommissioned projects from other states, the price for actual removal per turbine ranged from $27,285 to $651,725.[11] When scrap value is subtracted from cost, an average estimate of unrecovered dollars spent on decommissioning is about $25,500 per turbine.[12] The original estimate of $200,000 per turbine was calculated without scrap value deducted, and aligns with the

9. Molly Carroll, *Global Fiberglass Solutions Becomes the First US-Based Company to Commercially Recycle Wind Turbine Blades into Viable Products*, Global Fiberglass
Solutions (January 29, 2019) http://blog.global-fiberglass.com/blog/global-fiberglass-solutions-becomes-the-first-us-based-company-to-commercially-recycle-wind-turbine-blades-into-viable-products [https://perma.cc/4EZQ-7WL6].

10. *See supra* note 2; *see U.S. Wind Industry Fourth Quarter 2018 Market Report*, AM. WIND ENERGY ASS'N (Jan. 30, 2019), https://www.awea.org/getattachment/Resources/Publications-and-Reports/Market-Reports/2018-U-S-Wind-Industry-Market-Reports/4Q2018_public/U-S-Wind-Industry-third-Quarter-2018-Market-Repor/4Q-2018-AWEA-Market-Report-Public-Version.pdf.aspx?lang=en-US, [https://perma.cc/G4PG-LKF4].

11. Shannon L. Ferrell & Eric A. DeVuyst, *Decommissioning Wind Energy Projects: An Economic and Political Analysis*, ENERGY POL'Y 105, 110 (Feb. 2013).

12. *Id.* at 111.

national average cost of removal.[13] When you consider the uncertainty of the removal cost with the reality that our state has over 13,000 turbines that will someday need to be removed if not repowered, the problem of decommissioning is pushed into the spotlight.

The certainty is that decommissioning will come at a high cost and the landowner will likely not be equipped to bear the cost of turbine removal. Even renting the specialized equipment necessary would be next to impossible for a landowner; likewise, only trained professionals understand how to remove the equipment in such a way as to not cause harm to the underlying land. As you can imagine, landowners after years of bad experiences with oil and gas industries, were insistent that the wind companies be responsible for decommissioning.

III. BOOM AND BUST: LESSONS FROM THE OIL AND GAS INDUSTRY

Proponents of decommissioning regulation often point to the Texas problem of orphan oil and gas wells. Such wells are defined as wells not operational for more than twelve months. However, in reality, they are are more often old, abandoned wells left by financially distressed operators. These wells can create significant problems for a landowner, since they often leach toxic byproducts into the surrounding biosphere.[14] In Texas, the Railroad Commission operates a fund from taxpayer dollars that allows for the plugging of orphan wells, a program which is notoriously underfunded.[15] The Texas legislature and landowners are worried about similar decommissioning issues with wind turbines. Arguments for

13. Rick Kelley, *Retiring worn-out turbines could cost billions that nobody has*, VALLEY STAR (Feb. 18, 2017), https://valleymorningstar.com/news/local_news/article_3a81176e-f65d-11e6-b1bb-b70957ccb19f.html?mode=jqm, [https://perma.cc/AM9Y-QR76].

14. Sophie Quinton, *Why 'Orphan' Oil and Gas Wells Are a Growing Problem for States*, PEW CHARITABLE TRUSTS (July 9, 2018), https://www.pewtrusts.org/en/research-and-analysis/blogs/stateline/2018/07/09/why-orphan-oil-and-gas-wells-are-a-growing-problem-for-states; [https://perma.cc/4XKD-WNQH].

15. *See generally, Commissioner State Managed Plugging Monthly Reports*, RAILROAD COMM'N OF TEX., https://www.rrc.texas.gov/oil-gas/environmental-cleanup-programs/oil-gas-regulation-and-cleanup-fund/ogrc-plugging-monthly-reports/ (last visited Mar. 20, 2019), [https://perma.cc/TME4-FLGM]. (Well plugging data for 2016 to 2019).

decommissioning bonds are generated, in part, by this fear, addressing the issue of cleanup years before the issue actually arises.[16]

The Texas Utilities Code contains the equivalent of a decommissioning clause for oil and gas operators without requiring the operators to be backed by any financial obligation.[17] As a result, the boom and bust cycle, ever present in oil and gas production, has left thousands of wells abandoned and polluting the environment.[18] The Railroad Commission continues to levy taxes against operators to raise the money for plugging abandoned wells, but projected fund estimates fall well short of the needed capital.[19]

Since there is no requirement for oil and gas companies to set aside money or provide money upfront for plugging, the Texas treasury pays for plugging orphan wells. Orphan wells can create an even greater problem if they leach any byproducts into the surface, often leaving the landowner financially responsible for land remediation.[20] The resulting crisis has fueled the wind decommissioning debate from the beginning with many supporters of a decommissioning statute claiming the wind industry will eventually boom and bust like the oil and gas industry has historically done.

IV. ENTER THE BOND

Soon after the advent of the wind boom in Texas, lawyers began adding a provision to landowner leases stating that a wind company must post a bond to cover the cost of complete restoration of the property in the event the company is no longer financially able to remove the turbines. There is no set standard for removal, so the specifications for removal can be very specific, down to the exact reseeding schedule for reclaiming the land. The sophistication of the removal bond typically depends on the particular lawyer and landowner negotiating the lease.

16. Quinton, *supra* note 14, at 5.
17. 16 TEX. ADMIN. CODE §3.14(b)(2) (West 2007).
18. Brandon Mulder, *Old oil wells pose problem for Pecos County*, MRT (Aug. 22, 2015), https://www.mrt.com/business/energy/article/Old-oil-wells-pose-problem-for-Pecos-County-7413749.php, [https://perma.cc/VW2K-DWT2].
19. The Railroad Commission is estimated to have raised about $1,700,000 of the approximately $53,202,000 needed to plug about 8,400 abandoned wells throughout the state. *See* Kate Galbraith, *In Texas, Abandoned Oil Equipment Spurs Pollution Fears*, TEX. TRIB. (June 9, 2013), https://www.texastribune.org/2013/06/09/texas-abandoned-oil-equipment-spurs-pollution-fear/ [https://perma.cc/T552-VYM3].
20. Mulder, *supra* note 18.

Presently, most bonds are posted at or around year ten of the lease term, leading to one of the most frequently asked questions: why wait until year ten? When a bond was first contemplated, companies found the concept more palatable if the bond could be postponed until year ten—when the majority of companies were operating in the black (i.e. the cost of construction was paid through operation revenues). Additionally, before year ten, any lender with an outstanding interest in the project could sell the wind project to another management company and would be motivated to do so in order to avoid a massive loss in investment capital.

Bonds range in sophistication based on the landowners wishes and can be as exacting as which kind of seed mix will be used to reclaim the property or as transversely broad as to say that the company has to restore the property to as close to the condition it was before (which can leave much open for debate). Some leases and bonds include an agreement to leave the wind company roads, while some bonds will specify that all roads must be removed. It has been my experience that besides the financial aspects of a lease, decommissioning is often one of the most heavily negotiated aspects of a lease.

In fact, it is now rare to get a form lease without a decommissioning bond. This reality leaves one asking—if the decommissioning bond is already addressed by existing lease arrangements, what was the need for a Texas policy on decommissioning? The real concerns for policy makers are landowners who sign a wind lease without consulting reputable sources, and landowners who are willing to accept a lease form prepared solely by the company. Considering that there can be hundreds of landowners in a wind project, it may only be that a few owners consult a lawyer to add a bond.[21] For example, if only half of the landowners have adequate bonds for removal, only half of the turbines might be removed. Again, there is precedential fear from the oil and gas industry that insolvent companies will abandon wind farms, leaving landowners to deal with removing these large turbines.[22]

21. Wind leases contain confidentiality clauses so particular language is either confidential or protected by attorney/client privilege. *See* Roderick E. Wetsel & Lisa Chavarria, *Anatomy of a Wind Energy Lease*, ST. B. TEX.: 21ST ANN. ADVANCED OIL, GAS & ENERGY RES. L. COURSE, 1, 13 (Oct. 16–17, 2003).

22. Quinton, *supra* note 14.

V. DECOMMISSIONING WIND IN OTHER STATES

There are states that have currently abandoned wind projects giving decommissioning proponents rightful fear that Texas could go the wrong way. As a good example, Hawaii and California both have early wind projects which were subsequently abandoned by companies and left as the landowner's problem.[23] Some have estimated that as many as 4,500 turbines await removal in California alone. In Hawaii, private operator money removed 37 turbines for approximately $1 million dollars, recovering only $300,000 after scrapping the turbines for parts.[24]

Since California was an early proponent of wind power, its legislature was one of the first to address decommissioning. The California Natural Resources Code contains a blanket removal requirement for energy production facilities, requiring that the land be restored to pre-construction conditions, but provides no guidance as to how such restoration will take place.[25] The regulation was passed in 1975, before the influx in wind production, leaving California with no mechanism to enforce companies to remove turbines.[26] As mentioned above, California has thousands of turbines awaiting removal, highlighting that without a financial mechanism to ensure removal, there is no guarantee that turbines will be removed.[27]

Some states, such as Oklahoma and Indiana, have passed more exacting decommissioning bills.[28] Similar to Texas, people opposed a decommissioning statute in Oklahoma, claiming that the majority of leases already had decommissioning language in place.[29] Despite the arguments, Oklahoma passed decommissioning legislation to provide a sense of security for landowners. Oklahoma requires a removal

23. William S. Stripling, *Wind Energy's Dirty Word: Decommissioning,* 95 TEX. L. REV. 123, 124 (2016).
24. Duane Shimogawa, *Apollo Energy Removing Old Wind Turbines on Big Island*, PAC. BUS. NEWS (Mar. 29, 2012), http://www.bizjournals.com/pacific/blog/2012/03/apollo-energy-removing-old-wind.html [https://perma.cc/S8BS-EM65].
25. Stripling, *supra* note 23, at 136.
26. *Id.* at 136.
27. Bill Gunderson, GUNDERSON: *Some Basic Facts About Wind Energy*, WASH. TIMES (Mar. 16, 2013), http://www.washingtontimes.com/news/2013/mar/16/gunderson-some-basicfacts-about-wind-energy/?page=all [https://perma.cc/888V-4Y3D].
28. Stripling, *supra* note 23, at 141.
29. Shannon L. Ferrell & Eric A. DeVuyst, *Decommissioning Wind Energy Projects: An Economic and Political Analysis*, ENERGY POL'Y, 105–113 (Feb. 2013).

security of 125% of cost, estimated by an engineer, to be posted after a project is commissioned.[30] By requiring a decommissioning bill, Oklahoma legislators theorized that landowners are more likely to enter into a wind lease, boosting the Oklahoma economy associated with wind energy generation.[31] The 2017 Oklahoma decommissioning bill is one of the most recently passed laws, and largely the most influential on the Texas bill. However, it is difficult to determine the impact of such legislation at this time as these states also have newer wind facilities, and there are no known examples of any landowner having to rely on the bond for wind facility removal.

VI. HOUSE BILL 2845

In light of all the concerns about decommissioning, the Texas Legislature has attempted to pass a decommissioning bill for the last several sessions. In 2019, House Representative Terry Canales filed H.B. 2845 as a follow-up to his previously rejected decommissioning bill, H.B. 1717.[32] Representative Canales represents South Texas, an emerging new area for wind development. The region has become a new frontier for wind companies trying to take advantage of tropic winds, which blow during the afternoon at peak demand times for the use of electricity.[33] Canales had a tenacious desire to pass decommissioning assurances for future wind development, and as many of his constituents were former wind clients, his staff sought me out to consult and draft a decommissioning standard for the state.

In 2017, Canales made his first attempt to pass a decommissioning clause. H.B. 1717 reached far beyond decommissioning wind turbines and included a broad set of regulations for all wind companies: including auditing, record keeping, and plans to allow additional rulemaking authority for the

30. OKLA. STAT. ANN. tit. 17, § 160.15(B)(2) (2016).
31. Ferrell, *supra* note 29, at 105–106.
32. *See generally* HB 1717, TEX. LEG. ONLINE, https://capitol.texas.gov/BillLookup/History.aspx?LegSess=85R&Bill=HB1717 [https://perma.cc/G2LV-RB3N] (see for H.B. 1717 bill overview, language, and action history); HB 2845, TEX. LEG. ONLINE, https://capitol.texas.gov/BillLookup/History.aspx?LegSess=86R&Bill=HB2845 [https://perma.cc/Q2KW-SE3F] (see for H.B. 2845 bill overview, language, and action history).
33. Sergio Contreras, *Contreras: Wind Energy Booming in South Texas*, RIO GRANDE GUARDIAN (Feb. 20, 2019), https://riograndeguardian.com/contreras-wind-energy-booming-in-south-texas/ [https://perma.cc/WWB7-TZY5].

Railroad Commission to begin overseeing wind companies.[34] The bill was not well received in the industry and ultimately, H.B. 1717 failed in calendars with many citing the argument that such oversight of wind companies was unnecessary since the industry has not created any significant problems calling for regulation.

The 2019 bill attempted to gain traction by becoming a separate act under the Utilities Code rather than an amendment to the Natural Resources Code. This change was significant because the Railroad Commission would not have enforcement of breaches of H.B. 2845. Wind energy regulation by the Railroad Commission has been met with opposition since many fear that any regulation will slow the explosive growth within the industry. Rather than oversight by a state agency, the bill provides for injunctive relief in the event of a breach, allowing landowners to seek recourse in local courts where the land is located.[35]

With some amendment from my previous proposal, H.B. 2845 was signed into law on August 14th, 2019 and became Title 6 of the Texas Utilities Code. Section 301.0001[36] defines which wind facilities are subject to the new act as being all "Wind power facility" including wind turbines and support facilities.[37] Section 301.0002 provides that all agreements to waive the rights under the Act will be void, that relief sought will be injunctive and will not be deemed to waive other remedies under law.[38] Skipping ahead to § 301.004, the act requires that a decommissioning clause be placed in every new Texas wind lease, making the operating company responsible for financial assurances for removal of all wind facilities by the 10th anniversary of the project coming online.[39] The value of the financial assurance to be determined by an independent third party, which will include a reduction for any appraised scrap value of removed facilities.

34. Lisa Linowes, *The Texas Wind Power Story, Part 2: The Impacts of Texas Wind Power Siting*, TEX. PUB. POL'Y FOUND. (July 2018), https://files.texaspolicy.com/uploads/2018/07/07172726/2018-06-RR-TexasWindPowerStoryPart2-ACEE-LisaLinowes.pdf [https://perma.cc/T8MC-6W9N].

35. S.B. 1372, 86th Cong. (Tex. 2019).

36. TEX. UTIL. CODE ANN. § 301.0001 (West Supp. 2019).

37. Author Note: Already in practice, we have encountered solar leases using language similar to that of Title 6, Section 301. The act was authored as to only apply to wind turbines, leaving out other important consideration in the removal of solar panels. Considering the tenacity with which the people wanted decommissioning standards for wind, I suspect that a solar decommissioning bill will be proposed in the next few sessions.

38. TEX. UTIL. CODE ANN. § 301.0002 (West Supp. 2019).

39. TEX. UTIL. CODE ANN. § 301.0004 (West Supp. 2019).

The most important part of the bill, § 301.0003, provides specific requirements for removal of the wind turbines.[40] Aside from scrap value, these provisions are the most heavily negotiated items in a removal bond, since many landowners have exacting requirements for how their land should be restored. One should still bear in mind that the requirements under § 301.0003 are minimum standards, not a ceiling, and can be changed according to the needs of the landowner. However, with the passage of this bill, it has become increasingly difficult to convince companies to increase any of the bonding requirements. Companies are now copying § 301.0003 and stating in effect that they only have to do what is required by law.

VII. CONCLUSION

Similar to the early days of oil exploration, the wind industry in Texas boomed in the absence of regulation. I was among those Texans who first worried that any regulation would take the proverbial "wind out of the sails" of the booming wind industry. However, thinking also as a Texas landowner, there is no denying that all our farmers and ranchers will benefit from an assurance that turbines can be decommissioned at the end of the wind lease, particularly if the wind company (like so many oil and gas companies) are then insolvent.

Thankfully since enactment of H.B. 2845 on September 1, 2019, the Texas wind industry has continued to flourish. In fact, in many desolate and windy areas of the state, the economic future for landowners has never looked brighter. The additional good news for such landowners is that their children and grandchildren will not suffer if a future project owner lacks the funds to remove its equipment and clean up the family's land.

40. TEX. UTIL. CODE ANN. § 301.0003 (West Supp. 2019).

THE FIGHT FOR FOOTPRINT: ENERGY DEVELOPMENT AND COMPETING SURFACE USE ISSUES

James D. Bradbury, Courtney C. Smith & Chandler Schmitz[†]

I. INTRODUCTION

The laws surrounding energy development in Texas have evolved over the past century,[1] as Texas has been at the epicenter of the energy industry—and thereby, the center of energy law—since oil was discovered in Corsicana in 1894.[2] Domestic, and even some international choice-of-law clauses, choose Texas law due to the Lone Star State's dominance in the energy sector.[3]

While Texas is often closely tied to oil and gas, its strong position in the energy market is not limited just to this industry.[4] Texas is now the largest producer of wind energy and the seventh largest producer of solar energy in the United States.[5] The plans to exponentially increase production of these alternative types of energy in the next five to ten years is reflected by the $2.5 billion dollars that has been invested in wind and solar development in Texas.[6]

However, developing alternative energy sources creates an environment ripe for conflicts over land space as multiple parties seek to develop their respective forms of energy.[7] While everything is bigger in Texas, things could start to feel significantly smaller if companies seek to produce several types of energy on the same, or close, area of land.[8]

This Article discusses the advantages of Texas's continued growth in energy development—both traditional and alternative forms—and how to address the inevitable competition for land space

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1. Alan J. Alexander, *The Texas Wind Estate: Wind as a Natural Resource and Severable Property Interest*, 44 U. MICH. J.L. REFORM 429, 429–31 (2011).
2. *Id.*
3. *Id.*
4. *Id.*
5. *Texas State Profile and Energy Estimates,* U.S. ENERGY INFO. AND ADMIN. (Feb. 21, 2019), https://www.eia.gov/state/analysis.php?sid=TX#121 [https://perma.cc/GZ6R-XKVF].
6. *Id.*
7. J. Brent Marshall, *From Land or from Air: Why A Unified Energy Resource Scheme Is Necessary When the Answer Is Both*, 8 BARRY U. ENVTL. & EARTH L.J. 24, 25 (2018).
8. *Id.* at 26.

that will occur when development of different natural resources is pursued in the same area. The author will also suggest ways that landowners can seek to protect their surface estate and preserve the current uses, such as agricultural operations, on their land.

II. OIL AND GAS

In Texas, similar to many other states, landowners can sever mineral and surface estates.[9] Landowners can lease or sell the rights to one estate and retain the rights to the other. This is common when landowners lease mineral rights to oil and gas developers and retain rights to the surface estate in order to continue existing operations on the land.

Texas law is well-settled that the mineral estate is the dominant estate—meaning the surface estate is servient when it comes to developing minerals on the land.[10] Issues arise when there is interest in developing more than one energy source on a given area of land, as Texas law is not clear on what "mineral" is dominant or if energy sources may be severable by type of source—oil and gas, wind, solar, and etc.[11] A significant contributing factor to this conflict is that all the aforementioned energy sources require significant areas of surface space for development.

Accordingly, oil and gas developers that extract minerals from thousands of feet below the surface could be in direct competition with wind developers seeking to erect wind turbines. While this may seem counter-intuitive, the frustrating reality is that both operations require large areas of space, and often, more than one type of developer has a high interest in a particular area of land.

This leaves landowners and energy developers in a precarious situation of trying to determine how to proceed and which source has the dominant right to the land.[12] At this time, the answer seems to be the mineral developer that first leased the land, and development rights

9. Tiffany Dowell, *Texas Mineral Owner's Implied Right to Use the Surface*, TEX. A&M AGRILIFE EXTENSION: TEX. AGRIC. L. BLOG (Nov. 26, 2018), https://agrilife.org/texasaglaw/2018/11/26/texas-mineral-owners-implied-right-to-use-the-surface/ [https://perma.cc/4VMQ-9L8H].

10. Getty Oil Co. v. Jones, 470 S.W.2d 618, 621 (Tex. 1971); *see also* Merriman v. XTO Energy, Inc., 407 S.W.3d 244, 248–49 (Tex. 2013).

11. *See* WILL RUSS, INHERITING THE WIND: A BRIEF GUIDE TO RESOLVING SPLIT ESTATE ISSUES WHEN DEVELOPING RENEWABLE PROJECTS (2013), https://www.velaw.com/uploadedFiles/VEsite/Resources/SpecialInstituteRenewableElectricEnergyLawDevelopmentInvestment.pdf.

12. Marshall, *supra* note 7, at 45.

is likely the dominant estate and has the first right to develop.[13] However, without further legal clarity, this current modus operandi could crumble.

This is largely due to the fact that, historically, when mineral and surface estates have been severed, oil and gas development has been considered the dominant estate.[14] Accordingly, oil and gas developers would likely be able to block other wind and solar developments in favor of their own projects.[15]

Additionally, there is significant debate about whether wind and solar development should be considered mineral development or surface use.[16] While wind and solar projects help develop valuable resources, the mineral estate has traditionally been understood to involve "capturing" minerals from below the surface.[17] In response to this, wind and solar developers have begun implementing surface use agreements to strengthen their development rights.[18]

Surface use agreements are not novel in energy development in Texas. Landowners have long utilized these agreements to protect their surface use rights and to place certain restrictions on the reasonable access and area of land that oil and gas developers are authorized to utilize while operating on the land.[19] Landowners could use these agreements when leasing to oil and gas developers to narrow the area of land these developers have access to, which may create opportunities for other types of energy development on the land. Alternatively, these agreements could be used in leases for alternative energy development to protect the relevant land space and narrow the scope of surface availability for oil and gas development.

If other types of energy sources are currently being developed on a certain area of land, oil and gas developers have a duty to not interfere with those operations. Texas common law has established the accommodation doctrine, which requires oil and gas developers to operate in a reasonable manner and to not interfere with the current surface use of the land.[20]

13. *Id.*
14. *Id.* at 37–38.
15. *Id.* at 47–48.
16. *Id.* at 41–42.
17. *Id.* at 39–40.
18. Tara Righetti, *Contracting for Sustainable Surface Management*, 71 ARK. L. REV. 367, 384 (2018).
19. *Id.*
20. *Id.* at 371, 377.

Surface owners can utilize this doctrine to challenge oil and gas operations on their land by showing the following: (1) existing surface use is being substantially impaired; (2) there is no reasonable alternative that would allow surface use operations to continue; and (3) the mineral owner has reasonable alternatives that would not impair surface use and would allow mineral development to continue.[21] The accommodation doctrine could be used to protect existing alternative energy development on the land and as a method of forcing multiple developers to find ways to co-exist productively in a given space.

The Texas Railroad Commission has also established rules that restrict where oil and gas wells can be drilled. These rules regulate, among other things, the proximity of wells to each other, how close wells can be to property lines, and how many acres can constitute a drilling unit.[22] While there can be exceptions to these rules when developers show good cause for a specific project, these regulations work to narrow the reasonable access developers have to land and also require developers to place wells in positions that do not overly burden the surface estate.[23]

The oil and gas industry is a vital and valued part of Texas and its economy, but there is a need to facilitate oil and gas development alongside other types of mineral development throughout the state. While certain existing legal doctrines and regulations assist in facilitating this, there is a need for either Texas courts or the Texas legislature to address the severability of different mineral estates from each other and to establish how the dominant mineral estate should be determined.

III. WIND

Wind has been a power source for over 5,000 years when people began sailing and used wind to propel a ship in the desired direction. Today, wind energy is the fastest-growing form of energy production in the United States. While wind energy is a renewable energy source and is generated from something with an essentially

21. Dowell, *supra* note 9.
22. Brandon E. Durrett, *A Primer on Oil and Gas Regulations in Texas: Spacing, Density, Permits, Exceptions* LANDMAN MAG. 35–37 (2013), https://www.dykema.com/media/site_files/120_NO_ADS_Durrett_Pub-NA.pdf.
23. . *Id.* at 40–41.

unlimited supply, this form of energy development is not without its thorns.

Wind energy production requires more physical land space than most oil and gas production projects because of the space needed to operate wind turbines—namely that the turbines should, ideally, be between 1,000–3,000 feet apart. Wind turbines also need a large amount of "buffer space" to prevent obstructions from blocking the flow of wind to the turbines. These buffer spaces are typically one-half to one mile in distance and often require wind developers to acquire easements on neighboring properties so neighbors will not build structures that could create obstructions. The significant amount of surface space needed for wind production adds an additional layer of competition for land amongst energy developers in Texas.

Another thorn in the side of all parties involved in wind energy production is whether wind rights are severable from the surface estate, and who can—or should—be able to claim ownership of wind rights. Traditionally, property law theories would assign the right to wind flowing over a property to the owner of the surface estate.[24] The rapid development of wind energy has presented state courts and legislatures across the country with the opportunity to determine if wind rights can be "severed" from the surface estate of the property.[25]

Several states have found wind rights to be a severable estate, and others have expressly prohibited severing wind rights.[26] However, the majority of states, including Texas, have not made a formal determination about the severability of wind rights.[27] Despite the fact that Texas has not formally determined whether wind is an independently severable estate, many Texas landowners are essentially severing wind rights from their surface estates via the wind development leases they are entering into with wind developers.[28]

24. Russ, *supra* note 11, at 5.
25. *Id.*
26. *Id.*; *see generally* Troy A. Rule, *Wind Rights Under Property Law: Answers Still Blowing in the Wind,* 26 DEC. PROB. & PROP. 56, 57 (2012); Alan J. Alexander, Note, *The Texas Wind Estate: Wind as a Natural Resource and a Severable Property Interest*, 44 U. MICH. J.L. REFORM 429, 444–51 (2011) (discussing analogous theories of the ownership of wind rights, including the law of wild animals, groundwater law, and surface water law).
27. *See* Alexander, *supra* note 26, at 433.
28. *Id.* ("Despite a lack of legislative and judicial guidance on this question, wind leases in Texas are typically written as if wind rights are severable. Yet it is unknown whether Texas courts will recognize the severability of a wind estate.")

Although, the validity of these severances remains to be seen in Texas jurisprudence.[29]

In response to the ambiguous state of wind rights in Texas, landowners and wind developers are currently using ground leases that grant the wind developer the right to use the surface estate to construct and operate the wind turbines. This development also limits the access the landowner, invitees, or other future potential energy developers may have to the area needed for the turbines.[30] Surface use agreements are also used for wind development projects. These agreements still seek to protect the surface area needed for the wind project and also seek to delineate and protect the current or future rights of other direct and derivative estate owners on the land, such as oil and gas companies and pipeline companies.[31]

It is unclear how a conflict between the wind developer and the owners of other rights on a given property would be legally resolved. If the use pre-existed the wind development and is now impaired or prohibited by the wind development, other estate owners may be able to rely on the accommodation doctrine to preserve current uses of the land.[32]

However, the wind development industry in Texas—and all involved parties—will be relegated to operate in a nebulous space until the Texas legislature or the Texas courts determine whether the wind estate is severable from other rights on the land, and if so, whether this right should be considered part of the surface or mineral estate.

IV. SOLAR

Solar energy is another form of alternative energy that is rapidly growing across the nation, and specifically, in Texas. A hurdle that is inhibiting solar energy development is determining who owns the rights to the sun and to which estate—surface or mineral—these rights belong. Texas courts have not determined that solar rights belong to the surface estate, but many legal scholars believe that Texas courts would find solar rights to belong to surface estate owners.[33]

This is legally significant because the solar development would likely be part of the surface estate and therefore would be a

29. *Id.*
30. Russ, *supra* note 11, at 13.
31. *Id.* at 14.
32. *Id.* at 8.
33. Dowell, *supra* note 9.

servient estate to mineral development.[34] This could create a significant quandary if the landowner has leased both mineral rights below the land and solar development on the surface estate because the mineral owner has the right to use all the land reasonably necessary for mineral production. Thus, solar developers must carefully analyze the status of the mineral estate on a surface area that they are interested in developing.[35]

Another hurdle is the staggering amount of land required to produce this type of energy.[36] Solar production requires roughly 6,000 acres, and—unlike other types of energy development—this land is typically not usable for anything else.[37] This is something landowners should be wary of when considering entering into a solar development lease. Most of these leases include prohibitions against using the land on which the panels are placed, as well as certain surrounding properties that may interfere with the sun's access to the panels.[38] Further, many solar leases seek to prohibit certain agricultural operations, such as crop-dusting, which could be very detrimental to most rural landowners.[39]

While solar energy reduces a carbon footprint and utilizes a natural resource to produce clean energy, there are several unanswered legal and regulatory questions that create confusion and significant risks for those involved in solar production in Texas. The nebulous legal structure poses challenges to landowners and solar developers, and the nature of solar development is wholly adverse to other types of energy development because it renders the entire area of land unusable for any other purpose. For solar development to reach its potential, legal and regulatory advances must be made to determine ownership rights of solar rays and to which estate these rights belong.

V. WATER

The law surrounding groundwater ownership in Texas is far more settled, but that does not indicate that water development is without its challenges. Generally, groundwater is treated similar to oil and gas, and this legal theory was bolstered by the Texas Supreme

34. *Id.*
35. *Id.*
36. Ernest E. Smith et al., *Everything Under the Sun: A Guide to Siting Solar in the Lone Star State*, 12 TEX. J. OIL GAS & ENERGY L. 41, 55 (2017).
37. J. Brent Marshall, *supra* note 7, at 31.
38. Dowell, *supra* note 9.
39. *Id.*

Court's holding in *Coyote Lake Ranch v. City of Lubbock*.[40] Here, the Court held that groundwater estates were severable from surface estates and therefore subject to the accommodation doctrine.[41]

The Court's reasoning in this case illustrated that Texas jurisprudence is committed to treating groundwater similar to oil and gas—in other words, as a mineral estate—and Texas courts are likely to find groundwater development to be a dominant estate.[42] Texas courts also treat groundwater the same as oil and gas in that groundwater is subject to the rule of capture.[43] However, the groundwater estate must be expressly severed for it to be a separate estate. Otherwise, the groundwater is considered part of the surface estate.[44]

This treatment of groundwater presents a challenge when oil and gas development is in conflict with groundwater development, as it is unclear which of these "mineral" estates is dominant to the other.[45] At this time, there is no case law to determine how a court would proceed if both the groundwater and mineral estates have been severed and are in development conflict with one another.[46] To add a further wrinkle, there is no case law that determines how the accommodation doctrine would be utilized in the above scenario if there is also a conflict with surface use.[47]

Some legal scholars theorize that Texas's "first in time, first in right" theory would mean that the first estate to be severed would have the dominant rights.[48] However, Texas has a strong public policy in favor of energy—oil and gas—development, and this may cause Texas courts to consistently find the oil and gas estate is dominant, which would force groundwater development and surface uses behind the reasonable needs to develop oil and gas.[49]

40. Coyote Lake Ranch LLC v. City of Lubbock, 498 S.W.3d 53, 65 (Tex. 2016).
41. *Id.* This holding provided clarity as to the priority of groundwater development over surface estate uses, but it also ensured that surface estate owners may utilize the accommodation doctrine to protect existing surface uses.
42. Haley King, *Conflicts in Groundwater and Mineral Estates in Texas*, 48 TEX. ENVTL. L. J. 299, 307 (2018).
43. *Id.* at 301.
44. *Id.* at 299.
45. *Id.* at 308.
46. *Id.*
47. *Id.*
48. *See* Jared Berg, *Ending the Game of Chicken: Proposed Solution to Keep Texas Wind Developers and Mineral Lesses from Ruffling Each Others' Feathers*, 11 TEX. J. OIL AND GAS ENERGY L. 143, 156 (2016).
49. King, *supra* note 42, at 309.

These sticky legal situations will likely—sooner rather than later—require the Texas legislature or the Texas courts to provide a legal framework that determines the developmental hierarchy between groundwater and mineral estates. Additionally, a determination is needed as to how the accommodation doctrine should apply when surface estate uses conflict with severed groundwater and mineral estates to reconcile these three important but competing uses of land.

VI. CONCLUSION

Texas's booming energy market is the bedrock of Texas's strong economy and is a vital part of the state's continued growth and economic development. However, to ensure this growth continues, the Texas legislature or Texas courts must resolve competing uses for land space and development rights in Texas.

Both landowners and energy developers need a clear understanding of what rights are severable, how to contract to protect the viability of energy development projects, and how to protect landowners' important and existing surface uses. Further, developers need clarity as to which severable estates are dominant to one another and how conflicts will be resolved when two "dominant" estates come into developmental conflict with one another.