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Servitude Owner's Restoration Duties Terminated When Servitude Terminated

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In *Black River Crawfish Farms, LLC*, 2018 WL 739408 (La. App. 3rd Cir. 2018), a Louisiana landowner brought suit, alleging that its land had been contaminated by past oil and gas activities. The landowner acquired the land, about 189 acres in Concordia Parish, in 2003. The defendants included several individuals who previously had owned mineral servitudes covering the land. Under Louisiana law, a mineral servitude is somewhat like the severed mineral interest that can exist in other states, except that a servitude terminates automatically if there ever is a period of ten consecutive years without drilling or mineral production.[1] The landowner relied in part on Louisiana Mineral Code article 22 (La. Rev. Stat. 31:22), which provides that the owner of a mineral servitude "is obligated, insofar as practicable, to restore the surface to its original condition at the earliest reasonable time."

The district court dismissed the landowner's case. On appeal, the Louisiana Third Circuit noted that the last mineral activity had taken place in January 1990, when an operator had ceased the drilling of a dry hole. Therefore, under Louisiana Mineral Code article 27, the servitude had terminated in January 2000. The appellate court concluded that a servitude owner's duty under Mineral Code article 22 to restore the condition of the property is a duty that Louisiana law would classify as a "real obligation," but a real obligation is correlative to, and does not exist in the absence of a "real right." A real right is somewhat akin to an ownership interest, but which does not constitute actual ownership. "Real rights confer direct and immediate authority over a thing,"[2] as opposed to a mere contractual right to use a thing.

Here, the defendants previously had owned mineral servitudes. Mineral servitudes are real rights.[3] But those real rights had terminated in January 2000. Accordingly, the defendants' real obligation to restore the property also had terminated in January 2000. Therefore, the plaintiff did not have a cause of action against the defendants under Mineral Code article 22.

Given the Third Circuit's conclusion that the defendants' restoration obligation had terminated in January 2000, the court did not reach the question of whether the after-acquired title doctrine would apply in a suit against a mineral servitude owner. (The Louisiana Supreme Court held in *Eagle Pipe and Supply, Inc. v. Amerada Hess Corp.*, 79 So. 3d 246 (La. 2011) that a landowner has no cause of action in tort against a tortfeasor for damage to property that the tortfeasor caused before the landowner acquired the property.)

[1] See Min. Code art. 27 (La. Rev. Stat. 31:27).

[2] La. Civ. Code art. 476 cmt. (b).

[3] See La. Min. Code art. 16 (La. Rev. Stat. 31:16).

Where in the world is the owner of a mineral lease considered to be the owner of an "unleased" interest?

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Short answer: In Louisiana.

Louisiana law is well established that an unleased mineral servitude owner or an unleased land owner (a "UMO") is not entitled to share in production from a compulsory unit until the operator has been reimbursed the costs of drilling, testing, completing, equipping, and operating the unit well, out of production.[1] This point of time is called "payout."[2]

The dilemma of the UMO is that it has no way of ascertaining when "payout" occurs for this purpose.[3]

The Well Cost Reporting Statute, Louisiana Revised Statutes sections 30:103.1, *et seq.*, affords the UMO the opportunity to call upon the operator to certify as to the amount of costs being recouped, and to thereby permit the UMO to track the status of "payout." In brief summary, the "the owner or owners of **unleased** oil and gas interests" may call upon the operator to provide a "sworn, detailed, itemized statement" of "the costs of drilling, completing, and equipping the unit well."

Should the operator fail to properly and timely report to the UMO, it would incur the penalty prescribed by Louisiana Revised Statutes section 30:103.2, reading, as follows:

> **R.S. § 30:103.2. Operators and producers to report to owners of unleased oil and gas interests**
>
> Whenever the operator or producer permits ninety calendar days to elapse from completion of the well and thirty additional calendar days to elapse from date of receipt of written notice by certified mail from *the owner or owners of **unleased** oil and gas interests* calling attention to failure to comply with the provisions of R.S. 30:103.1, such operator or producer shall forfeit his right to demand contribution from *the owner or owners of the **unleased** oil and gas interests* for the costs of the drilling operations of the well.[4]

What is meant by "the owner or owners of *unleased* oil and gas interests"? Recent litigation addressed the issue of whether the Well Cost Reporting Statute may be availed only by a UMO (one who is truly unleased to any party), or also by a mineral lessee of an interest not under lease to the operator.

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[1] La. Rev. Stat. Ann. § 30:10A(2).

[2] "Exchange apparently made a prediction that the well would never 'pay out,' that is, the value of production from the unit would never be sufficient to repay Exxon for all unit well costs." *Shanks v. Exxon Corp.*, 674 So. 2d 473, 474 (La. App. Ct. 1st), *writ den'd* 679 So. 2d 436 (La. 1996).

[3] See Patrick S. Ottinger, After the Lessee Walks Away–The Rights and Obligations of the Unleased Mineral Owner in a Producing Unit, 55 ANN. INST. ON MIN. LAW 59 (2008).

[4] La. Rev. Stat. Ann. § 30:103.2. (Emphasis added.).

For example, in *TDX Energy, LLC v. Chesapeake Operating, Inc.*,[5] TDX sued the operator, saying that it had forfeited its rights to recover well costs by failing to provide well-cost information under the Well Cost Reporting Statute.

The plaintiff, TDX, was a mineral lessee, not the owner of an unleased interest; it was not a UMO.

The court granted Chesapeake's motion for summary judgment that the Well Cost Reporting Statute only inures to the owner of a truly unleased mineral interest, and may not be availed by a lessee under a mineral lease in which the operator owns no interest.

The Fifth Circuit, United States Court of Appeal, reversed,[6] paying *Erie*-deference and adopting the view of a Louisiana appellate court in another case.[7]

In that state case, the court also held that a lessee under a mineral lease, who had no contractual relationship with the operator, and who did not agree to share in the cost, risk and expense of drilling the unit well, comes within the ambit of the phrase "the owner . . . of unleased oil and gas interests." A writ application in the state case was denied by the Louisiana Supreme Court. The Louisiana Supreme Court has noted that a "writ denial by this Court has no precedential value."[8]

It has been held that the Well Cost Reporting Statute, being penal in nature, "should be construed strictly against the party seeking to impose the penalty."[9] This means, at a minimum, that, if two interpretations of the statute are available, the court should choose the narrow one, not an expansive interpretation. Yet the Fifth Circuit, United States Court of Appeal, in *TDX* elected to follow the *XXI* decision, which (as the court stated) "followed the latter, more expansive view."[10] This is clearly contrary to the rule of strict construction of a penal statute.

Resolution of this issue by the Louisiana Supreme Court must await a future case. However, until clarification by the Louisiana Supreme Court, or by legislative action, if the operator receives a proper demand for well-cost information from a lessee, one needs to evaluate the risk of non-compliance.

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[5] 2016 WL 1179206, Civil Action No. 13-1242, W.D. La. In the interest of full disclosure, this author represented the defendant-operator in this suit.

[6] 857 F. 3d 253 (5th Cir. 2017).

[7] *XXI Oil & Gas, LLC v. Hilcorp Energy Co.,* 124 So. 3d 530 (La. App. Ct. 3d 2016); 206 So. 3d 885, *writ den'd* 216 So. 3d 814 (La. 2017). In the interest of full disclosure, this author represented the defendant-operator in this case to prepare and prosecute a writ application to the Louisiana Supreme Court, but did not represent the defendant at the trial or appellate level.

[8] *See*, *e.g.*, *St. Tammany Manor, Inc. v. Spartan Bldg. Corp.*, 509 So. 2d 424, 428 (La. 1987); *So. Cent. Bell Tel. Co. v. Traigle*, 367 So. 2d 1143, 1150 (La. 1978). *See also Ehrlicher v. State Farm Ins. Co.*, 171 F. 3d 212, 214, n.1 (5th Cir. 1999) (noting that the Louisiana Supreme Court's denial of writs, without explanation, "leaves us with no binding authority to resolve the question, because a denial of a writ of certiorari neither constitutes an approval of the court of appeal's decision nor does it create precedent.").

[9] *Scurlock Oil Co. v. Getty Oil Co.*, 324 So. 2d 870, 877 (La. App. Ct. 3d 1975).

[10] 857 F. 3d at 259.

University of Cincinnati Study Finds No Adverse Impact on Groundwater from Oil and Gas Activity

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A group of researchers from the University of Cincinnati recently published the results of a study in which they found no adverse impact on groundwater quality from drilling and hydraulic fracturing in the Utica Shale.

The study began in January 2012 and lasted through 2015. The researchers collected 180 groundwater samples from private water wells in five counties in Eastern Ohio (Carroll, Harrison, Stark, Columbiana, and Belmont) where there is a substantial amount of drilling into the Utica Formation. The sampling was based on landowner interest—all participation was voluntary and free. The number of samples depended on landowner interest. Several samples were collected at different times from some water wells, while at other wells only a few samples or even only a single sample were collected. The researchers sampled for overall methane concentration, methane isotopic concentration, pH, and conductivity.

The researchers had hypothesized at the start of the study that oil and gas activity would adversely impact water wells, leading to greater methane concentration in groundwater at sites near active natural gas wells, and to an increase in methane concentration over time as the amount of oil and gas activity increased. They also hypothesized that, due to impacts from oil and gas activity, the pH of groundwater would decrease and the conductivity would increase. But those hypotheses did not bear out.

The researchers reported that they "found no relationship between CH_4 concentration or source in groundwater and proximity to active gas well sites." Further, they did not find a deterioration in groundwater quality during the three-year study period, even though hundreds of Utica Shale wells were drilled in the area during that time. The researchers reported: "No significant changes in CH_4 concentration, isotopic composition, pH, or conductivity in water wells were observed during the study period."

Further, to the extent that the researchers found some methane in groundwater, isotopic analyses generally suggested that the source was biogenic (the decay of organic matter), rather than thermogenic (as would be the case if natural gas was the source of the methane). The researchers stated that their data "indicate that high levels of biogenic CH_4 can be present in groundwater wells independent of hydraulic fracturing," and that this "affirm[s] the need for isotopic or other fingerprinting techniques for CH_4 source identification." In other words, even when methane is found in groundwater, it can have natural sources that are unrelated to oil and gas activity, and additional testing often is necessary to determine the true source.

The study received funding in part from a couple of entities that have been unfriendly to oil and gas activity. Some media outlets quoted one of the researchers as stating that some of the donors were "disappointed" with the research results because those donors had hoped the results would support a ban on hydraulic fracturing, and that the groups had ceased funding the project after the researchers reported their preliminary findings that oil and gas activity, including hydraulic fracturing, had not had an adverse impact on groundwater.

The researchers recently reported their results in a paper entitled *Monitoring concentrations and isotopic composition of methane in groundwater in the Utica Shale hydraulic fracturing region of Ohio*, which was published on-line on May 3, 2018 in the journal “Environmental Monitoring and Assessment.” The authors were E. Claire Botner, Amy Townsend-Small, David B. Nash, Xiomei Xu, Arndt Schimmelmann, and Joshua H. Miller.

EPA Grants Primacy to North Dakota for CCS Injection Wells

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The EPA has approved an application that North Dakota submitted under Section 1422 of the Safe Drinking Water Act (42 U.S.C. § 300h-1) to implement an underground injection control (UIC) program for Class VI injection wells within North Dakota, except on Indian lands. Class VI is the class of UIC wells designated for the injection of carbon dioxide for purposes of storage.[1] The effect of this approval is that North Dakota will have "primacy," which means that the State of North Dakota will have primary enforcement responsibility of the Safe Drinking Water Act (SDWA) for purposes of Class VI wells. North Dakota's Class VI UIC program will be run by the state's Industrial Commission, the same agency that regulates oil and gas activity. North Dakota already had primacy with respect to Class I, II, III, IV, and V UIC wells. North Dakota is the first state to gain primacy for Class VI wells.

The process by which North Dakota acquired primacy took several years. The state held a public hearing regarding its intent to adopt a Class VI UIC program in April 2012, then accepted public comments for more than a month after that. The state held a second public hearing later in 2012, then submitted its application for primacy to the EPA in June 2013. In May 2017, the EPA issued a proposed rulemaking to grant primacy and solicited public comments. Finally, in April 2018 the EPA issued a final rule that approved North Dakota's application. North Dakota's regulations are found at Chapter 43-05-01 of the North Dakota Administrative Code.

Because carbon capture and storage (CCS) is rarely used at present, the EPA's approval of North Dakota's application for primacy with respect to Class VI wells will not be significant in the short run, but it could have significant effect in the longer run. Carbon capture and storage (CCS), sometimes called "carbon capture and sequestration," would involve the capture of carbon dioxide from some source—such as the effluent from a coal-fired power plant or the emission from a chemical plant—and the injection of the carbon dioxide into the subsurface for permanent storage. CCS is only being used in a few places worldwide, but CCS is getting increased attention because of concerns about climate change. Some sources state that the earth's countries have little chance of satisfying the aggressive climate change goals using only energy conservation and increased use of renewable sources of energy, and that the only hope of meeting previously-adopted goals is to implement carbon capture and storage on a broad scale. If the United States, or a substantial number of individual states, ever implements a tax on emissions of carbon dioxide, the tax might spur a substantial demand for use of CCS, and possibly for wells that combine CCS with enhanced oil recovery.

The use of CCS is regulated under the Safe Drinking Water Act, a federal law enacted in 1974 in order "to assure that water supply systems serving the public meet minimum national standards for protection of public health."[2] Part C of the SDWA, codified at 42 U.S.C. § 300h, *et seq.*, governs subsurface injections for purposes of protecting underground sources of drinking water (USDWs). Part C requires the EPA to develop regulations for state underground injection control ("UIC") programs, including "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources."[3]

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[1] See 40 C.F.R. § 144.6(f).

[2] H.R. Rep. No. 93-1185 (1974); Miami-Dade Cnty. v. EPA, 529 F.3d 1049, 1052 (11th Cir. 2008).

[3] See 42 U.S.C. § 300h.

Under the SDWA, the general rule is that no person may inject fluids into the subsurface without first obtaining a permit pursuant to the SDWA. If a state has primacy for the type of injection well that a person wishes to operate, a state agency is the permitting authority, even though the SDWA is a federal statute. If a state does not have primacy for the relevant type of injection well, the permitting authority is the EPA Regional Office for the state in which the proposed injection would take place. States may apply for primacy by showing that they have enacted a UIC program that meets certain federal standards. To the extent that oil and gas lawyers encounter the SDWA, they often encounter it in the context of Class II wells—the class of wells that include: wells for the injection disposal of produced water; injection wells used for secondary or tertiary recovery operations; and wells used to inject liquid hydrocarbons into the subsurface for storage. The SDWA's Class II regulations also apply to injections performed for the purpose of hydraulic fracturing, but only if the fracturing fluid contains diesel (otherwise, the SDWA does not apply to hydraulic fracturing).

Ohio Law Does not Support an Implied Covenant of Further Exploration

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In *Alford v. Collins-McGregor Operating Co.*, 95 N.E.3d 382, (Ohio 2018), the Ohio Supreme Court held that Ohio law does not recognize an implied covenant of further exploration that is "separate and apart from the implied covenant of reasonable development." On the other hand, the court did not seem to necessarily foreclose the possibility that the implied covenant of reasonable development might sometimes include a duty to drill exploratory wells. To appreciate the relevance of this case, it is important to recall the difference between the implied covenant of reasonable development and the potential implied covenant of further exploration.

The implied covenant of *reasonable development* generally requires the leaseholder to drill as many wells as a reasonably prudent operator would drill to develop the leased premises. Because a reasonably prudent operator would not drill a well unless it is likely to be profitable, a lessor cannot prevail on a claim for a breach of this implied covenant without proving that the lessee failed to drill a well that likely would have been profitable. This implied covenant has been recognized by virtually all authorities.

A much smaller number of authorities recognize both an implied covenant of reasonable development and a separate implied covenant of further exploration. These authorities distinguish the separate covenants in two ways. First, they describe the reasonable development covenant and the further exploration covenant as applying in different locations. As for the implied covenant of reasonable development, they define it slightly narrower than it is described above. Instead of describing it as being an obligation to drill all of the wells that a reasonably prudent operator would drill to develop the *leased premises*, they describe it as a duty to drill the "development wells" that a reasonably prudent operator would drill to develop *proven formations* that are within the leased premises. In contrast, they describe the implied covenant of *further exploration* as requiring a leaseholder to drill any "exploratory wells" that a reasonably prudent operator would drill to explore *unproven areas*.

The second way that the authorities who recognize a separate implied covenant of further exploration distinguish this covenant from the reasonable development covenant relates to the likely profitability of a sell. These authorities accept the reasoning that, in order to prove a breach of the implied covenant of reasonable development, a lessor must prove that the lessee failed to drill a well that likely would have been profitable. But these authorities contend that an implied covenant of further exploration could sometimes require the drilling of a well even if the likelihood of profit does not exceed fifty percent. Presumably, these authorities reason as follows. The drilling of an additional "development well" to a proven formation will merely speed the recovery of hydrocarbons from a known formation. Thus, a reasonably prudent operator would not drill such a well unless the well likely would be profitable. In contrast, the drilling of a successful "exploratory well" can lead to enormous profits by finding a previously undiscovered pool of hydrocarbons. Thus, a reasonably prudent operator sometimes will drill an exploratory well in an unproven area even if the likelihood of success does not exceed fifty percent.

As noted above, virtually all jurisdictions that have any significant amount of oil and gas jurisprudence have recognized the existence of an implied covenant of reasonable development, and none have rejected its existence. In contrast, very few courts have recognized the existence of a separate implied covenant of further exploration, and the highest courts of a couple of major oil and gas states have expressly rejected its existence. But this does not mean that the courts which reject the existence of a separate implied covenant of further exploration have indicated that a lessee will never have an implied obligation to drill an exploratory well. Instead, those courts appear to be open to the possibility that the "reasonable development" covenant can include a duty to drill wells that a reasonably prudent operator would drill to either a proven formation or an unproven one, but that such a duty will not exist unless the well would likely be profitable.

For example, the Texas Supreme Court has expressly rejected the existence of an implied covenant of further exploration. In doing so, however, the court expressly stated that once production from the leased premises is achieved, the covenant "to develop the premises" requires the lessee to drill whatever additional wells a reasonably prudent operator would drill to either a proven formation or an unproven formation, but that this duty does not require the lessee to drill a well unless the well would likely be profitable.[1] (Of course, it generally would be extremely difficult for a lessor to prove that, if a proposed well was drilled into an unproven formation, it likely would be profitable.).

The Oklahoma Supreme Court has reached a similar result. In *Mitchell v. Amerada Hess Corp.*, 638 P.2d 441, 447 (Okla. 1981), the court discussed a prominent commentator's proposal for a covenant of further exploration that could require the drilling of wells to unproven formations, even if it is not probable that such a well would be profitable. The court declined to recognize such a covenant, holding that "there is no implied covenant to further explore after paying production is obtained, as distinguished from the implied covenant to further develop."[2] But the court did not reject the possibility of an implied duty to drill a well to an unproven formation. Rather, the court merely held that any such duty falls under the reasonable development covenant, not a separate covenant, and that the duty will not exist unless the well is likely to be profitable.

> Can the duties of the lessee be judged apart from the spectre of profit where the activity is judged exploration rather than development? To do so is unwise and unnecessary. The machinery to adjudicate an "exploration" controversy exists presently in the form of the covenant to diligently develop. The element of chance in achieving a profit from any given drilling project is invariably present and varies from a development situation to an exploration only in its magnitude.[3]

The Ohio Supreme Court seems to have reached a similar conclusion. In *Alford*, the plaintiffs are lessors under a 1980 lease covering about 74 acres of land in Washington County, Ohio. The lessee drilled a well to the Gordon Sand in 1981. The well has produced oil and gas in paying quantities since that time and had held the lease. In late 2015, the plaintiffs filed suit, asserted that the lessee has breached an implied covenant of reasonable development and an implied covenant of further exploration. In particular, the plaintiffs asserted that other operators have begun producing oil and gas near their property from two formations located below the Gordon Sand—namely, the Marcellus and Utica formations. The plaintiffs further alleged that their lessee had failed to drill to the Marcellus and Utica formations because the lessee lacks the financial resources to do so. As a remedy for the alleged breach, the plaintiffs sought cancellation of the lease as to all depths below the Gordon Sand.

The trial court granted the lessee's motion to dismiss, holding that Ohio law does not recognize a remedy of partial forfeiture of a lease by depth. The appellate court affirmed, then the

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[1] See Sun Exploration & Prod. Co. v. Jackson, 783 S.W.2d 202, 204 (Tex. 1990) (citing Clifton v. Koontz, 325 S.W.2d 684, 696 (Tex. 1959)).

[2] 638 P.2d at 449.

[3] Id. at 447.

Ohio Supreme Court granted review. Before the Ohio Supreme Court, the plaintiffs argued that partial termination by depth is a permissible remedy for the breach of an implied covenant of further exploration, but the plaintiffs failed to argue that the lessee had breached an implied covenant of reasonable development. This failure may have been a mistake.

At paragraph 24 of its opinion, the Ohio Supreme Court noted that it need not address whether the lessee had breached an implied covenant of reasonable development "because the Landowners have raised only the implied covenant to further explore." Thus, reasoned the court, it only needed to address whether an implied covenant of further exploration exists under Ohio law (the court stated that this was "a covenant we have not before considered") and, if so, whether partial forfeiture by depth is an allowable remedy.

The Court noted that both the Texas Supreme Court and Oklahoma Supreme Court have "declined to recognize an implied covenant to explore further separate and apart from the implied covenant of reasonable development." The Ohio Supreme Court stated that "the Landowners' interests in exploration of deep formations below the Gordon Sand are sufficiently protected by the implied covenant of reasonable development. We therefore decline to recognize a separate covenant to explore further." Later in the opinion, the Court stated that "the implied covenant of reasonable development is well suited to address the primary driver of the Landowners' interests here, namely, the emergence of new drilling technologies permitting production from deep strata that could not be obtained before."

The Court's language can be read as holding the plaintiffs had waived any right to rely on the implied covenant of reasonable development by characterizing their claims as being based on an implied covenant of further exploration (which the Court held does not exist under Ohio law), but as leaving the door open for a plaintiff to argue that a lessee has breached the implied covenant of "reasonable development" by failing to drill a well to a new formation. Notably, the Court did not identify the elements necessary to prevail on a claim alleging a breach of the implied covenant of reasonable development. Thus, the Court did not expressly state that, under Ohio law, a duty to drill a well will not exist under the reasonable development covenant unless the well is more likely than not to be profitable, but that is the rule under the implied covenant jurisprudence of most states.

Alleged Trespass by Hydraulic Fracturing Fluid and Proppants

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A recent appellate court decision from Pennsylvania considered whether an operator can be liable in trespass for conducting a hydraulic fracturing operation that results in hydraulically-induced fractures, as well as fracing fluid and proppants, to intrude into the subsurface of a neighboring tract for which the operator does not have an oil and gas lease. The court held that an operator can be liable. In doing so, the court reached a conclusion contrary to that reached by the Texas Supreme Court when a mineral estate owner and lessor brought such a claim in the well-known case *Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d (Tex. 2008).

In *Briggs v. Southwestern Energy Production Co.*, __ A.3d ___, 2018 WL 1572729 (Pa. Super. Ct. 2018), the plaintiffs are the owners of an approximately 11-acre tract of land in Susquehanna County, Pennsylvania. Southwestern holds an oil and gas lease on a neighboring tract, but not on the plaintiffs' tract. The plaintiffs brought suit in late 2015, apparently alleging that Southwestern has conducted hydraulic fracturing within the Marcellus formation on the leased tract, and that the hydraulic fractures crossed into the subsurface of the plaintiffs' tract, along with fracing fluid and proppants. As a result, the plaintiffs allege, Southwestern has recovered natural gas that originally was located beneath the plaintiffs' land.

The plaintiffs assert that this constituted a subsurface trespass, and that Southwestern is liable to them under the theories of trespass and conversion. The plaintiffs, who seek compensatory and punitive damages, apparently do not allege any harm other than the loss of hydrocarbons. Southwestern filed a motion for summary judgment, asserting that under the facts alleged the company cannot be liable for trespass. The plaintiffs responded with a motion for partial summary judgment on the issue of liability. The trial court denied the plaintiffs' motion, granted Southwestern's motion, and dismissed the case. The plaintiffs appealed.

Southwestern's briefing relied in part on the Texas Supreme Court's decision in *Garza*. In that Texas case, the plaintiff owned a mineral estate that was subject to an oil and gas lease. The plaintiff alleged that the defendant had conducted hydraulic fracturing operations on neighboring land. Although the plaintiff did not allege that the defendant committed a surface trespass or that the defendant's wellbore intruded into the subsurface of the tract where the plaintiff owned the mineral estate, the plaintiff contended that hydraulic fractures had crossed the subsurface property line, and that fracing fluid and proppants had intruded via those fractures. The plaintiff alleged that this caused hydrocarbons to flow from beneath the tract where the plaintiff owned rights, into the subsurface of the tract where the defendant was operating, and ultimately into the defendant's wells. The plaintiff asserted that these facts made the defendant liable in trespass. The plaintiff did not allege any other harm other than the loss of hydrocarbons.

The Texas Supreme Court's majority decision in *Garza* concluded that, because the plaintiff did not own a possessory right in the tract where the trespass alleged had occurred, and instead merely owned a reversionary interest, the plaintiff would not have a claim in trespass unless it incurred damages. The majority further concluded that the rule of capture would preclude a claim for the drainage of hydrocarbons from beneath the plaintiff's tract to a wellbore beneath the neighboring property, where the defendant had a right to operate. Because the plaintiff did not claim any damages other than the loss of hydrocarbons, the plaintiff had no compensable damages. Therefore, the plaintiff did not have an "actionable trespass." For this reason, concluded the majority, the court did not have to reach the question of whether a subsurface intrusion of fracturing fluid and proppants would constitute a trespass in the event that a plaintiff had incurred compensable damages (or in a case in which a plaintiff need not prove damages in order to prevail on a trespass claim).

A concurring opinion would have held that a subsurface intrusion of fracturing fluid and proppants would not constitute a trespass. A dissenting opinion in the *Garza* decision from Texas had concluded that it was premature to dismiss the case without addressing whether a subsurface intrusion of fracturing fluid and proppants could constitute a trespass. The dissenting opinion suggested that the rule of capture might not apply if the alleged intrusion was a trespass. The *Briggs* defendant—Southwestern—relied on the majority opinion.

The *Briggs* plaintiffs relied on *Young v. Ethyl Corp.*, 521 F.2d 771 (8th Cir. 1975). In Young, the United States Eighth Circuit made an *Erie*-guess regarding how Arkansas law would resolve the parties' dispute. The case involved the recovery of bromine, which is found in some subsurface brine. The recovery process works somewhat like a secondary recovery operation. Brine is produced from production wells, and bromine is recovered from the brine. The remaining fluid is then pumped into the same formation using injection wells, and the injection helps push more brine toward the production wells. The plaintiff in *Young* alleged that the defendant's injections were pushing bromine-rich brine from beneath the subsurface of the plaintiff's land. The Eighth Circuit concluded that the rule of capture did not preclude the plaintiff's claim.

In *Briggs*, the Pennsylvania appellate court discussed *Garza* and *Young*, as well as *Stone v. Chesapeake Appalachia, LLC*, No. 5:12-CV-102, 2013 WL 2097397 (N.D. W. Va. Apr. 10, 2013), order vacated, 2013 7863861 (N.D. W. VA. July 30, 2013) (original decision apparently vacated at the request of the parties after a settlement). *Stone* involved facts similar to those in *Garza*. A division of the United States District Court for the Northern District of West Virginia rejected the defendant's motion for summary judgment, thereby effectively holding that a subsurface intrusion of fracturing fluid can constitute a compensable trespass, even if the only harm alleged by the plaintiff is the loss of hydrocarbons. In doing so, the federal district court rejected the reasoning of the Texas Supreme Court in majority in *Garza*.

In *Briggs*, the appellate court reversed the trial court's judgment dismissing the plaintiffs' case on summary judgment. On an issue of first impression, the appellate court held that the rule of capture would not preclude Southwestern from being liable for drainage of hydrocarbons caused by any fractures that intrude into the subsurface of the plaintiffs' land. The court stated that the rule of capture traditionally has assumed that oil and gas are migratory in nature, but that natural gas found in shale formations is non-migratory "absent the application of external force." Echoing concerns expressed in *Stone* and by the dissent in *Garza*, the court expressed concern that precluding trespass liability in such circumstances would "eradicate" a company's incentive to negotiate leases with small property owners. The court also doubted whether the landowners' self-help remedy—to drill their own well—was an effective remedy given the costs of drilling a well to the Marcellus Formation and hydraulically fracturing it. Although the court reversed the summary judgment in favor of Southwestern, the court did not reverse the trial court's denial of the plaintiffs' motion for partial summary judgment on the issue of liability. The appellate court explained that the record before the court did not establish whether a subsurface intrusion had occurred.

Texas Supreme Court Interprets Retained-Acreage Clauses

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On April 13, 2018, the Texas Supreme Court resolved an apparent appellate court split between *XOG Operating LLC v. Chesapeake Expl. Ltd.*[1] and *Endeavor Energy Res., L.P. v. Discovery Operating Inc.*[2] concerning the interpretation of retained-acreage clauses.

A common provision in oil and gas leases, a retained-acreage clause defines what portion of an oil and gas lease an operator will retain after the primary term of its lease. In *XOG* and *Endeavor* the Court firmly established how any differences in retained-acreage clauses are to be interpreted going forward—apply a "reasonable" reading of the "plain language" of the clause.[3] A court will look to the retained-acreage clause's text to determine how much acreage will be retained by an operator in a lease's secondary term, which may be different from the acreage the operator assigned to a particular well in a P-15 Railroad Commission proration form.

Background

Highly similar factually, both the *XOG* case and the *Endeavor* case center around disputes as to whether the operators of an oil and gas lease (Chesapeake and Endeavor) had lost their rights to some portion of the properties they had leased. On one side, the operators contended that they had the right to all of the acreage under their respective oil and gas leases. And on the other side, the lessors contended that the operator's rights to the land during their secondary term should be limited to the acreage the operators identified in the proration unit forms they filed with the Texas Railroad Commission. In both cases, success for the lessors would have meant that the operators would lose the rights to half of the acreage that they had leased.

Although the retained-acreage clauses that governed the outcome of both disputes were similar, they differed slightly in the way that they defined what property either operator would retain rights to in their secondary terms. Specifically, both clauses differed in the extent to which they referenced the proration forms the operators filed with the Railroad Commission.

In *XOG* for example, the retained-acreage clause stated that the operator's "assigned interest would revert to XOG after the primary term, 'save and except that portion of the leased acreage'…'included within the proration…unit' 'prescribed by field rules' or, 'absent…field rules,' 320 acres."[4] While in *Endeavor*, the retained acreage clause stated that the operator's lease "'shall automatically terminate as to all lands and depths covered herein, save and except' certain lands within certain governmental proration units 'assigned to' a producing well."[5]

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[1] *XOG Operating, LLC v. Chesapeake Expl. Ltd. P'ship*, No. 15-0935, 2018 Tex. LEXIS 308, 2018 WL 1770506 (Tex. Apr. 13, 2018), *aff'g*, 480 S.W.3d 22 (Tex. App.—Amarillo 2015) [hereinafter *XOG,* and all cites to Westlaw].

[2] *Endeavor Energy Res., L.P. v. Discovery Operating, Inc.*, No. 15-0155, 2018 Tex. LEXIS 316, 2018 WL 1770290 (Tex. Apr. 13, 2018), *aff'g*, 448 S.W.3d 169 (Tex. App.—Eastland 2014) [hereinafter *Endeavor*, and all cites to Westlaw].

[3] *Endeavor*, at *9.

[4] *XOG*, at *1.

[5] *Endeavor*, at *2.

The Court's Decision

In companion opinions, the Court sided with the operator in the *XOG* case and the lessor in the *Endeavor* case. Seemingly contradictory, the Court reconciled these results by explaining that they were the outcome of a thorough individualized analysis of the language of the retained-acreage clauses in both cases.

Since retained-acreage clauses are "contractual," the court stated, it should be of no surprise that they "vary widely because parties are free to contract in any way they choose not prohibited by law."[6] Therefore, how retained-acreage clauses are interpreted will "turn on [their] text."[7] It is the court's responsibility to give a "reasonable" reading of the retained-acreage provisions "plain language" to determine its meaning.[8] "And as with any contract, the parties to a retained-acreage provision are presumed to know the law and to have stated their agreement in light of it."[9]

Accordingly, in the *Endeavor* decision, the Court paid special attention to the retained-acreage clauses use of the phrase "assigned to" in order to determine how it should be interpreted.[10] As the court explained, "the Commission does not 'assign' acreage to proration units—it merely quantifies the amount of acreage an operator assigns."[11] So, "within this regulatory context" the use of the word "assign" "can only refer to the operator's assignment."[12] Therefore, the Court found that when the parties used the phrase "assigned to" in their retained-acreage clause, they were attempting to identify the land the operator identified in its proration form as the land that should be retained by the operator in the secondary term of its lease. For this reason, the Court found that the Lessor's theory of the retained-acreage clause's interpretation was correct and held that the retained-acreage clause preserved only 81 acres per well even though the field rules allowed 160 acres per well.

Conversely, in *XOG*, since the parties did not use any terms of art that flagged an intent to retain the acreage identified in the proration form as the acreage that should be retained by the operator in the secondary term of its lease, the Court came to a different result. There, the parties clearly stated that the land that should be retained by the operator should be the acreage identified in the "field rules" or "absent…field rules" 320 acres.[13] A typical practice in oil and gas contracts, parties often "refer to [these field rules] as the lodestar for determining which acreage has been obtained and which acreage has been surrendered" in the context of a retained-acreage dispute.[14] Since the field rules were specifically invoked as a lodestar in *XOG*, the Court sided with the operator's interpretation of the retained acreage clause by holding that the operator was entitled to the entirety of the acreage it leased, rather than the 160 acres it designated in the proration form it filed with the Railroad Commission.

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[6] *XOG*, at *3.

[7] *XOG*, at *1.

[8] *Endeavor*, at *9.

[9] *XOG*, at *3.

[10] *Endeavor*, at *10.

[11] *Endeavor*, at *10.

[12] *Endeavor*, at *10.

[13] *XOG*, at *1.

[14] *Endeavor*, at *6.

Key Takeaways

A. Terms of art in an oil and gas lease will be strictly applied

The Court's decisions in *XOG* and *Endeavor* emphasize the importance of the agreement language in interpreting retained-acreage clauses. Where parties use terms of art like "assigned to" or "field rules," the Court will focus on these terms to glean from them any evidence of the parties' original intent. As in other instances of contract interpretation, the Court will assume that the parties to a retained-acreage clause are aware of the law and negotiated in light of it. Therefore, even if parties are not specifically aware of a term of art's use, the Court will require the parties to "meet 'the condition which they imposed upon themselves....For their failure to do so they have only themselves to blame.'"[15]

B. Reinforces incentives for operators to maximize acreage in proration units under the field rules

Often, oil and gas fields have field rules that dictate how much acreage can be assigned to any producing oil and gas well. This assignment process can determine the profitability of a well because it limits how much oil and gas can be recovered from any particular well for conservation purposes. Operators assign acreage to an oil or gas well by filling out a P-15 form and filing it with the Texas Railroad Commission.

The decisions in *XOG* and *Endeavor* have provided further incentivizes for operators to maximize the allowable acreage when filling out their proration forms. In that way, an operator will never risk, as in *Endeavor*, losing rights to acreage that it originally leased because the operator attributed less acreage to a well in a P-15 form than was allowed by field rules. Although doing this may "open [an operator] up to claims that it is not acting in good faith and purporting to retain a substantially greater amount of acreage"[16] than it should be entitled to, depending on the profitability of the oil and gas lease, this may be a risk worth taking.

C. Proration forms are not dispositive in a retained-acreage clause dispute

"The Commission's statewide rules typically require operators to designate a well's acreage and proration unit by filing certified plats and other forms, such as a P-15 form."[17] Although a P-15 form describes the acreage that should be associated with a particular well, the decision in *XOG* illustrates that this acreage assignment by an operator is not dispositive in resolving a retained-acreage dispute. As in *XOG*, a court will look to the retained-acreage clause's text to determine how much land will be retained by an operator in its secondary term (in *XOG* the field rules), not necessarily how much land that operator assigned to a particular well in a P-15 form.

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[15] *Endeavor*, at *13.

[16] *Endeavor*, at *12.

[17] *Endeavor*, at *4.

Court Finds That County Ordinance in West Virginia Prohibiting Storage and Permanent Disposal of Wastewater Was Preempted by State Law

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Under the facts presented in *EQT Production Company v. Wender,*[1] EQT operated one underground injection control well (UIC) located in Fayette County, West Virginia. The well was used to dispose of wastewater generated by hundreds of conventional vertical producing oil and gas wells operated by EQT both within and outside the county.[2] EQT injected the wastewater underground into a confined, underground formation for permanent disposal. EQT's operation of the UIC well was subject to state regulations, and was authorized by a state-issued permit. Further, in the interest of protecting underground sources of drinking water, EQT's disposal operations were also subject to federal regulation (administered by the state) under the Safe Drinking Water Act, 42 U.S.C. § 300f *et seq.* which imposes certain regulations on injection wells.

Notwithstanding the state and federal regulations, Fayette County enacted, on January 12, 2016, a blanket ban on all permanent disposal of wastewater within the county.[3] The Ordinance also banned the storage of wastewater at conventional well sites.[4] The Ordinance stated that the ban would "specifically apply to injection wells for the purpose of permanently disposing of natural gas waste and oil waste."[5] On January 13, 2016, immediately after the ordinance was enacted, EQT filed suit in the United States District Court for the Southern District of West Virginia to enjoin key aspects of the Ordinance as being preempted by state and federal law.

The district court entered a temporary restraining order and preliminary injunction in favor of EQT. Both parties moved for summary judgment. EQT argued that the Ordinance's ban on operation of its state-licensed injection well was preempted by West Virginia's UIC permit program. Because West Virginia's UIC permit program was not only enacted pursuant to state law and also mandated by the federal Safe Drinking Water Act, EQT argued that the Ordinance's ban on injection wells was preempted by federal law. The district court granted summary judgment to EQT and permanently enjoined the challenged provisions of the Ordinance.[6] The defendants appealed.

In reviewing the preemption issues presented in this appeal, the Fourth Circuit described one of the first questions to be addressed as being the following:

> Under West Virginia law, may the County prohibit EQT from engaging in precisely the activity—permanent disposal of wastewater at the UIC well—that has been sanctioned by a state permit, effectively nullifying the license issued by West Virginia's DEP pursuant to state statutory authority? . . .We need only determine whether a West Virginia county is authorized to take aim at the permitted activity

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[1] 870 F.3d 322 (4th Cir. 2017).

[2] *Id.* at 327.

[3] The ordinance was entitled "Ordinance Banning the Storage, Disposal, or Use of Oil and Natural Gas Waste in Fayette County, West Virginia." *Id.*at 328.

[4] 870 F.3d at 336.

[5] *Id.* at 328.

[6] *EQT Prod. Co. v. Wender,* 191 F.Supp.3d 583 (S.D.W. Va. 2016).

itself, enacting a blanket prohibition on conduct specifically licensed by the state.[7]

The court observed that counties of the State have only the limited powers granted to them by the West Virginia Constitution and the Legislature. The court noted that it would make no sense to assume that the State would delegate to a county, a creature of the State, the power to undo the State's permitting scheme.[8] Finding that all local law in the State is subject to the implied condition that the law may not be inconsistent with state law and must yield to the predominant power of the state, the court held that the Ordinance's ban on the operation of EQT's UIC well was preempted by state law.

The County argued that the savings clause of the West Virginia Water Pollution Control Act,[9] which governs the state's permitting of UIC wells, recognized that the County had the authority to enact ordinances for the elimination of hazards to the public health and to abate anything the commission determined to be a public nuisance. The court found that the County's argument proposed an unreasonably broad interpretation of the Water Pollution Control Act's savings clause. The court concluded that a more logical reading would be to view the clause as providing clarification that the possession of a state permit would not preclude all local regulation touching on the licensed activity. For example, the County might bring a common law action for public nuisance with respect to state-permitted UIC wells. The Fourth Circuit noted that "[a] county has the 'power to abate nuisances, not to determine what shall be considered nuisances.'"[10] The court concluded that the Ordinance's prohibition on all disposal of wastewater in UIC wells was preempted by state law.

The court then reviewed the Ordinance's restriction on the storage of wastewater at conventional well sites. Having already found that the Ordinance's core prohibition on permanent wastewater disposal was preempted, the court noted that there was little left to discuss concerning the ancillary storage restriction. Considered separately, the Ordinance's restriction on storage was found to be inconsistent with the state Oil and Gas Act and was preempted. The Oil and Gas Act vests the state Department of Environmental Protection with "exclusive authority over regulation of the state's oil and gas resources, including 'all matters' related to the 'development, production, storage and recovery of this state's oil and gas.'"[11] The court found that the DEP's authority extended to the regulation of the storage of wastewater at conventional production well sites.

The Fourth Circuit affirmed the judgment of the district court in all respects.

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[7] 870 F.3d at 332.

[8] *Id,* at 333.

[9] See W. Va. Code § 22-11-27, which provide in part: "[N]othing herein contained shall abridge or alter rights of action or remedies ..., nor shall any provisions ... be construed as estopping the state, municipalities, public health officers, or persons ... in the exercise of their rights to suppress nuisances or to abate any pollution...."

[10] 870 F.3d at 336.

[11] *Id.* W. Va. Code § 22-6-2(c)(12).

West Virginia Amends Statute Regulating Flat Rate Royalties

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During its 2018 Regular Session, the West Virginia Legislature amended West Virginia Code § 22-6-8, a statute which effectively precludes the use of flat-rate royalties. Under the prior language, the statute provided that if a lease provides for a flat rate royalty on oil or gas, the State of West Virginia would deny certain necessary permits to the lessee unless the lessee agreed to pay a one-eighth royalty based on the amount "received … at the wellhead." In 2017, the West Virginia Supreme Court held in *Leggett* that, for purposes of the statute, the work back could be used in determining the amount "received … at the wellhead." The 2018 legislation amends the statute to preclude the use of the work back method, and to require a lessee who has a lease that includes a flat-rate royalty to agree to pay a one-eighth royalty on the gross proceeds, without a deduction of post-production costs.

1. The Flat Rate Royalty Statute

Early in the history of the oil and gas industry, natural gas often had little value and leases often provided for a modest, fixed sum of money to be paid to the lessor as compensation for production of natural gas. West Virginia had oil and gas activity early enough in the industry's history that some leases were granted in the state using such "flat rate" royalties, and some of those leases are still in effect.

In 1982, the West Virginia legislature passed legislation that attempted to preclude the use of flat rate royalties, even under existing leases. Rather than attempting to abrogate or modify such leases outright, which might run afoul of the Contracts Clause of the United States Constitution, the 1982 legislation took an alternative approach. It provided that, if a lessee has a lease that provides for a flat rate royalty on oil or gas, the state would not grant the lessee any new permits to drill unless the lessee agreed to pay a royalty of at least one-eighth of the amount "received … at the wellhead."

2. *Wellman* and *Tawney*

Around the country, lessors and lessees have battled over the "deductibility" of post-production costs. These disputes arise from the fact that the royalty clauses in many oil and gas leases use language that is now something of an anachronism. Many leases specify that the lessee will pay the lessor a royalty on natural gas that is: (1) a specified fraction, such as one-eighth or one-fifth, etc. (2) of the value of gas or the proceeds of sale of the gas, (3) either "at the well" or "at the wellhead" or "at the mouth of the well" or "calculated at the well," etc. In the past, this language often worked pretty well because natural gas pipeline companies often purchased natural gas in the field, taking delivery at some point not too distant from the wells, before the natural gas had been treated to remove moisture and impurities, compressed to pipeline pressures, and then transported to some distant purchaser, and the pipeline company incurred the so-called post-production costs of such treatment, compression, and transport. In such cases, the lessor and lessee shared the value that the natural gas had in its raw state at a location near the well.

But in the process of deregulating natural gas markets, the federal government pushed pipeline companies toward becoming common carriers that simply transported the gas for a fee. As a result, oil and gas lessees often are not selling natural gas in its raw state or in a location near the well. Instead, the lessees are treating, compressing, and paying to transport the gas via pipeline to a distant customer. This creates a difficulty in determining the royalty under the language used in many leases. If the royalty is to be a fraction of the proceeds of a sale *at the wellhead*, but the gas is not sold at the wellhead, what is the royalty? If the royalty is to be a fraction of the value of the gas *at the well*, but there is no sale of gas at or near the well, and thus no direct evidence of value at the well (under the theory that value is the price to which a willing buyer and seller would agree), what is the royalty?

As most readers know, one way to estimate the value at the well (or to estimate what the proceeds of sale might have been at the well if there had been a sale at the well) is to use the "work back" method, also sometimes called the "netback" method. Under this method, the value at the well is estimated as being equivalent to the ultimate sales price of the gas minus the so-called post-production costs incurred up until the time of sale. Thus, if the gas is sold to a distant utility at $3.75 per thousand standard cubic feet, and the lessee had spent $0.75 on treating, compressing, and transporting the gas between the emergence of the gas from the well and the sale of the gas to the utility, the work back method would estimate the value of the gas in its raw condition at the well as being $3. This method makes some economic sense as a way to estimate value at the well, and the use of this method has been accepted in some states. But other states have rejected this methodology, sometimes based on reasoning that the implied covenant to market obligates the lessee to absorb all post-production costs unless the royalty clause explicitly provides otherwise.

West Virginia is one of the states that has rejected the work back method as a way of calculating the royalty owed under leases that provide for a royalty based on proceeds or value at the well. In *Wellman v. Energy Resources, Inc.*, 557 S.E.2d 254 (W. Va. 2001), the West Virginia Supreme Court held that the implied covenant to market requires the lessee to pay a royalty based on the proceeds or value at the point of sale, unless the royalty clause clearly provides otherwise. In *Tawney v. Columbia Natural Resources, Inc.*, 633 S.E.2d 22 (W. Va. 2006), a lessee argued that the "at the well" language in a royalty clause was sufficiently clear to justify use of the workback method, but the West Virginia Supreme Court disagreed, holding that such language was ambiguous. Therefore, whether based on the fact that the ambiguity would be construed against the lessee or the reasoning that an ambiguous clause was not sufficient to override the duty recognized under *Wellman*, the result in *Tawney* was that the royalty would have to be paid on the value (or proceeds) at the point of sale.

3. *Leggett*

In *Leggett v. EQT Production Co.,* 800 S.E.2d 850 (W. Va. 2017), the West Virginia Supreme Court considered whether the work back method could be used in calculating the royalty to be paid on natural gas when the lease provides for a flat payment—that is a so-called fixed royalty—on natural gas, rather than a fractional royalty, but the lessee has agreed to pay a one-eighth royalty under the prompting of West Virginia's flat-rate royalty statute, West Virginia Code § 22-6-8. The court held that the work back method could be used in those circumstances. The court noted that the statute referred to the amount received at the well and that the work back method makes economic sense for determining the value at the well. Further, when the statute was enacted in 1982 such language typically would result in the lessor and lessee sharing the value of gas in its raw state at a location near the well. Use of the work back method preserves that.

Further, *Leggett* explained that the reasoning of *Wellman* was not applicable. *Wellman* was based on implied covenant duties, whereas *Leggett* was dealing with a duty imposed by statute. Further, the reasoning of *Tawney* was not applicable. In *Tawney*, the court had interpreted an ambiguous contractual clause against the lessee, holding that the clause was not sufficiently clear to supersede the implied covenant duties. But neither the doctrine that ambiguous clauses should be interpreted against the oil and gas lessee nor implied covenant jurisprudence could resolve how to interpret a statute and how to apply a statutory duty. Therefore, neither of those cases precluded use of the work back method. Accordingly, use of the work back method was allowed for purposes of calculating a royalty obligation for purposes of the flat-rate royalty statute.

4. The 2018 Legislation

In some quarters, the reaction to *Leggett* was very negative. Indeed, the West Virginia legislature reacted by passing Senate Bill 360 during the 2018 Regular Session. The legislation, which passed by an overwhelming margin, amends West Virginia Code § 22-6-8. The amended statute provides that, if a lease contains a flat-rate royalty on oil or gas, West Virginia will not grant any permits to drill a new well unless the lessee agrees to pay a royalty of at least one-eighth of "gross proceeds, free from any deduction for post-production expenses, received at the first point of sale to an unaffiliated third-party purchaser in an arm's length transaction." The legislation becomes effective on about May 31, 2018.

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