Top Ten Texas Oil and Gas Cases of 2018 - Part 2 of 3

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This is a continuation of the three-part series that began last month discussing significant oil and gas decisions from state courts in Texas during 2018. It is not intended to be a strict legal analysis, but rather a useful guide for landmen in their daily work. Therefore, a complete discussion of all legal analyses contained in the decisions are not always included.

4. Dimock Operating Co. v. Sutherland Energy Co. LLC, No. 07–16–00230–CV, 2018 WL 2074643 (Tex. App. — Amarillo, April 24, 2018, pet. filed) (memorandum opinion)

This case discusses the impact of certain key contractual provisions within a farmout agreement, and it displays how the court will interpret such provisions based on the farmout's express language. Dimock yet again highlights the importance of paying close attention to the express language in your oil and gas agreements, as standard provisions within oil and gas agreements frequently vary in wording.

Dimock Operating Co. and Dimock entered into a seismic exploration and farmout agreement in which Dimock (farmor) farmed out 15 sections in Hardeman County to Sutherland (farmee). The parties agreed that upon "project payout," Sutherland would assign well operations and a 51 percent working interest back to Dimock, and the remaining 49 percent would be assigned to various charities. "Project payout" was the point at which revenues equaled two times Sutherland's capital costs. A dispute subsequently arose as to whether Sutherland reached payout.

This case addresses four significant oil and gas issues. First is whether costs incurred by Sutherland after drilling its initial well constitute "capital cost[s]" and should therefore be considered in determining whether Sutherland reached "project payout." The SEFA expressly defined Sutherland's capital cost as "cost[s] incurred by Farmee [Sutherland] for land and seismic for the Hamrick Area 3D Shoot … a fifty thousand dollar ($50,000) prospect fee, and cost for drilling, testing, completing, and equipping, the Initial Earning Well." Land and seismic costs were undefined. The court found that, contrary to Dimock's argument, "land and seismic costs" were not ambiguous merely because the terms had no contractual definitions. Nor were the terms "deposit" and "prospect fee" ambiguous within the agreement. Additionally, one punctuation mark cost Dimock a financial blow: a comma. Dimock argued that the placement of the comma after the word "equipping" made the definition of "capital costs" ambiguous. The court disagreed and concluded that it was a grammatical error to contend that the comma's placement indicated a modifying element — seismic costs were "capital costs" under the SEFA.

Interestingly, at trial, Sutherland passed up the opportunity to obtain a ruling from the trial court that "project payout" had not occurred. Instead, it requested that the court find that "capital costs" included the cost of undertaking seismic operations — a fact that Sutherland assumed would resolve the question of project payout. The Court of Appeals did not find the solution so simple. There was a finding about whether project payout had occurred, but there was no finding on whether the capital costs claimed by Sutherland were actually proper under the SEFA. Of the 66 points of error Dimock raised on appeal, many were reversed and remanded to the trial court for further proceedings because there was no adjudication of these key issues.

Next, Dimock argued that the joint operating agreement executed along with the SEFA obligated Sutherland to seek the consent of the nonoperators before incurring expenses associated with the seismic operations. The court disagreed. The SEFA provided Sutherland with the "sole, exclusive and irrevocable right to conduct Seismic Operations" and the right to "use its sole discretion to determine the type, nature, timing, and extent of all Seismic Exploration Operations." The operating agreement, in contrast, obligated Sutherland as the operator to seek consent from nonoperators for any project reasonably estimated to cost more than $25,000. Sutherland argued that the JOA was not effective as between Dimock and Sutherland until after project payout — when Dimock actually owned an interest in the contract area. The court disagreed with Sutherland yet ruled in Sutherland's favor on this issue. The SEFA stated that the SEFA would serve as the governing agreement in the event of any conflict between the operating agreement and the SEFA. Language giving Sutherland discretion to determine when to conduct seismic operations prevailed over the subsequent operations language in the JOA.

While the trial court did not specify the reason it concluded that Sutherland had the right to conduct the seismic operations, the controlling language within the SEFA could have served as the basis for such a holding. Therefore, the Court of Appeals affirmed the trial court's judgment.

Dimock also brought a claim for fraud alleging Sutherland falsely represented that seismic analysis was needed to locate the proper drill site, thus inducing Dimock to include seismic costs in the parties' agreement. Contrary to its representations, Sutherland did not undertake seismic operations prior to drilling the first well. Sutherland alleged Dimock did not reasonably rely on this alleged misrepresentation. The court concluded that Sutherland did not conclusively negate justifiable reliance, however, and that summary judgment on Dimock's fraud claim was improper and would be remanded for trial.

Finally, Dimock alleged Sutherland breached its fiduciary duty. The JOA created a contractual fiduciary duty requiring Sutherland to properly account for the distribution of well proceeds to Dimock. Dimock alleged that Sutherland breached this duty by failing to distribute the well proceeds to Dimock and converting them for Sutherland's own use. The court recognized that while a JOA alone does not generally create a fiduciary relationship, the "Custody of Funds" provision (which is standard most model forms of the JOA) states that the agreement does not establish a fiduciary relationship between the parties "for any purpose other than to account for Non-Operator funds as herein specifically provided." This language effectively created a contractual fiduciary duty to Dimock from Sutherland to properly account for the distribution of well proceeds. Because the court identified unresolved fact issues as to this claim, summary judgment on the claim was improper as well and would be remanded for trial.

5. Devon Energy Production Co. L.P. v. Apache Corp., No. 11-16-00105-CV, 2018 WL 2022699 (Tex. App. — Eastland, April 30, 2018, pet. filed)

In this case of first impression, the Eastland Court of Appeals held that Section 91.402 of the Texas Natural Resources Code (the "Division Order Statute") does not require an operator to pay lease royalties to mineral interest owners who have leased to a different working interest owner. And, by implication, the court held that such mineral interest owners are not entitled to royalties under the Division Order Statute until payout of the well from which royalties are due.

Norma Jean Hester leased her undivided one-third mineral interest in a tract of land in Glasscock County to Apache, reserving a 25 percent royalty. The remaining mineral owners leased their combined two-thirds mineral interest to Devon, also reserving a 25 percent royalty. Devon and Apache were unable to agree on a JOA. Apache then drilled seven producing oil and gas wells on the property and, after payout, paid Devon its two-thirds share of the production revenue net of Apache's costs. Apache left it to Devon to pay the Devon lessors their quarter royalty.

The Devon lessors sued Devon and Apache alleging generally that they had not been paid all royalties due under their leases with Devon, among other claims. Devon filed a cross-claim against Apache seeking a declaratory judgment that the Division Order Statute required Apache to pay the Devon lessors' royalties under Devon's leases: (i) directly and (ii) before payout of Apache's wells. Devon alleged Apache was then to charge those royalty payments against Devon in determining the wells' payout point.

The Eastland Court of Appeals noted the rules of equitable accounting among mineral co-tenants are well established. "A cotenant has the right to extract minerals from common property without first obtaining the consent of his cotenants; however, he must account to them on the basis of the value of any minerals taken, less necessary and reasonable costs of production and marketing." It was also clear that Devon and Apache, as lessees, were co-tenants in the mineral estate.

However, the question of which co-tenant must pay royalties to the lessors of a nonparticipating working interest owner under the Division Order Statute has never been addressed by the Texas appellate courts. The statute provides as follows:

"The proceeds derived from the sale of oil or gas production from an oil or gas well located in this state must be paid to each payee by payor on or before 120 days after the end of the month of first sale of production from the well. After that time, payments must be made to each payee on a timely basis according to the frequency of payment specified in the lease or other written agreement between payee and payor."

Siding with Apache, the court focused on the words "payor" and "payee" in the statute to determine Devon — not Apache — was obligated to pay the Devon lessors. A "payor" is "the party who undertakes to distribute oil or gas proceeds to the payee, whether as the purchaser of the production of oil or gas generating such proceeds or as operator of the well from which such production was obtained or as lessee under the lease on which royalty is due." A "payee" is "any person legally entitled to payment from the proceeds derived from the sale of oil or gas from an oil or gas well located in this state."

The court held Apache and the Devon lessees did not have a "payor-payee relationship" under the Division Order Statute because Apache did not "undertake" to pay the Devon lessors by entering into leases with them. Thus, even though Apache was the "operator of the well from which … production was obtained," it was not a "payor" under the Division Order Statute. Thus, paying the Devon lessors their lease royalty was Devon's obligation, not Apache's.

The court's opinion did not expressly address the issue of when a royalty owner who has leased to a nonparticipating working interest owner is entitled to royalties pursuant to their lease — before or after payout. However, the court's opinion appears to have answered that question by implication. The Division Order Statute does not require an operator to pay royalties to mineral interest owners who have leased to a different working interest owner. And Texas co-tenancy law does not require the operator to pay net production revenues to a nonparticipating co-tenant until after payout. Thus, absent special lease provisions, a mineral estate lessor is not entitled to lease royalties from a well drilled by the lessee of a different mineral estate co-tenant until after payout of the well from which royalties are due. Until that point, the operator is not required to pay net production revenue to the other lessee/nonparticipating co-tenant, and the other lessee/nonparticipating co-tenant has received no revenues on which royalties are due to his lessor.

6. TRO-X L.P. v. Anadarko Petroleum Corp., No. 16-0412, 2018 WL 2372805, (Tex., May 25, 2018)

This case is a cautionary tale about failing to draft robust "anti-washout" clauses. In 2007, TRO-X entered into five mineral leases covering acreage in Ward County, Texas. The leases contained identical terms, including a 660-foot offset well clause. TRO-X later entered into a participation agreement transferring its interest in the 2007 leases to Eagle Oil and Gas and reserving a 5 percent back-in option once the 2007 leases reached "project payout." The participation agreement contained an "anti-washout clause" providing that TRO-X's back-in option "shall extend to and be binding upon any renewal(s), extension(s), or top lease(s) taken within one year of termination of the underlying interest."

Eagle Oil and Gas eventually assigned its interest in the 2007 leases to Anadarko. A year later, Anadarko completed a well on land adjacent to the tract covered by the 2007 leases approximately 550 feet from the lease line. Anadarko then failed to drill an offset well within the required period. When one of the lessors alleged Anadarko breached the 2007 leases' offset well clause, Anadarko engaged all of the lessors in negotiations that culminated in their executing new leases. These 2011 leases were with the same lessors and covered the same mineral interest as the 2007 leases, but they did not release — and in fact did not even mention — the 2007 leases. The 2011 leases all specified an effective date of June 17, 2011, and were executed on various dates between June 15 and June 30, 2011, on which date Anadarko executed a written release of the 2007 leases. When TRO-X later approached Anadarko to confirm that its back-in interest in the 2011 leases was valid, Anadarko denied that it was.

TRO-X filed suit against Anadarko in February 2014 asserting claims for breach of contract and trespass to try title. The case was tried to the bench, with the central issue being whether the 2011 leases were "top leases" in which TRO-X retained its back-in interest or new leases that washed out TRO-X's interest. Anadarko argued the very act of executing the 2011 leases terminated the 2007 leases. Therefore, according to Anadarko, the 2011 leases were not top leases because they were never in effect at the same time as the 2007 leases. TRO-X, however, argued the 2007 leases remained in effect until Anadarko executed its release. Therefore, according to TRO-X, the 2007 and 2011 leases were all in effect between June 17, 2011 (the 2011 leases' effective date) and June 30, 2011 (the date Anadarko executed its release of the 2007 leases). Thus, TRO-X alleged the 2007 and 2011 leases were in effect at the same time, albeit briefly, and thus the 2011 leases were top leases subject to TRO-X's back-in interest. The trial court sided with TRO-X. The El Paso Court of Appeals reversed, holding that TRO-

X had not proved the parties intended the 2011 leases to be top leases. The Texas Supreme Court granted review.

The court began its analysis with the familiar maxim that mineral leases are interpreted using the same rules applied to other contracts. Thus, whether the parties intended the 2011 leases to be top leases must first be determined by reviewing the 2011 leases' plain language. If the plain language unambiguously provided the 2011 leases were or were not top leases, the inquiry is complete. The court then explained that, "[b]ascially, a top lease is a subsequent oil and gas lease which covers one or more mineral interests subject to a valid, subsisting lease." A top lease becomes effective only upon termination of the bottom lease.

The court then summarized the law regarding lease termination through execution of a new lease in three parts. First, "when a lessor and lessee under an existing lease execute a new lease of the same mineral interest subject to the existing lease, the existing lease is terminated unless the new lease objectively demonstrates both parties' intent otherwise[.]" Second, "[a] party contending that a new lease did not terminate the previous one has the burden to prove and obtain a finding that the parties intended for the previous lease to survive execution of the new lease." And third, "[t]he proof must be either specific language in the new lease objectively demonstrating that intent, or an ambiguity in the new lease as to termination of the previous lease together with evidence that the parties did not intend the new lease to terminate the prior lease."

The court found the 2011 leases did not contain language indicating the parties intended the 2007 leases to survive the 2011 leases' execution. Therefore, the 2007 leases were terminated by the 2011 leases' execution and were never in effect at the same time as the 2011 leases. Accordingly, the 2011 leases were not top leases and were not subject to TRO-X's back-in interest. The fact that Anadarko executed a release of the 2007 leases a few days after some of the 2011 leases were executed was irrelevant because the 2011 leases were unambiguous.

One might assume that TRO-X's back-in interest could easily have been preserved if the parties had included language in the participation agreement making the anti-washout clause applicable to "new leases." However, on July 26, 2018, the Amarillo Court of Appeals held that such a clause violates the Rule Against Perpetuities. In light of the Texas Supreme Court's opinion in TRO-X, the Amarillo Court's opinion in Yowell will be one to watch in 2018-2019.

STAY TUNED….

Next month, we will discuss the final four cases that may have an impact on your daily work. We hope this series will help you address the legal issues presented by modern oil and gas activities. As always, if you believe one of these decisions might have a bearing on an action you are about to take or a decision you might make, consult a lawyer.

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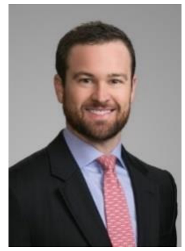

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