

# BLOOD AND OIL: EXPLORING POSSIBLE REMEDIES TO MINERAL COTENANCY DISPUTES IN TEXAS

*Caleb A. Fielder, Esq.\**

I.	INTRODUCTION.....	173
II.	INTRODUCTION TO THE DOCTRINE OF COTENANCY .....	176
III.	ECONOMICS.....	179
IV.	STRATEGY .....	184
	<i>A. Partition</i> .....	184
	<i>B. Top Lease</i> .....	187
V.	ACCOUNTING: NECESSARY AND REASONABLE EXPENSES.....	192
	<i>A. Categorical Exceptions</i> .....	193
	1. <i>Dry Holes</i> .....	193
	2. <i>Interest</i> .....	194
	3. <i>Workovers, Frac Jobs, and Other Wellbore Operations</i> .....	194
	4. <i>Overhead</i> .....	196
	<i>B. Payout: Tract-Basis or Well-by-Well Basis?</i> .....	197
VI.	OTHER CONSIDERATIONS .....	199
	<i>A. Who Owes the Royalty?</i> .....	199
	<i>B. Partition by Sale</i> .....	202
	<i>C. Amend Where Possible</i> .....	204
VII.	CONCLUSION.....	205

*Exploration programs are not conducted in an isolated vacuum. One whiff of a potential new play and suddenly the play is packed with flippers, lease-busters, top-leasers, land-owner groups, plaintiffs' attorneys, and other carpet baggers—"you will never find a more wretched hive of scum and villainy" . . . you must be cautious.<sup>1</sup>*

## I. INTRODUCTION

Texas, unlike many other states with long histories of oil and gas production (for example, Louisiana and Oklahoma), has little or no forced pooling legislation.<sup>2</sup> This lack of forced pooling can present a quandary for

---

\* B.A., University of Texas, 2003; J.D., *with honors*, University of Texas School of Law, 2007. Landman, lawyer, and negotiator, Houston, Texas.

1. STAR WARS: EPISODE IV-A NEW HOPE (Twentieth Century Fox 1977).

2. See, e.g., Bruce M. Kramer, *Compulsory Pooling and Unitization: State Options in Dealing with Uncooperative Owners*, 7 J. ENERGY L. & POL'Y 255, 259 n.16 (1986). Texas's Mineral Interest Pooling Act does provide for forced pooling in limited circumstances. *Id.*

an entity seeking to drill and explore for oil and gas.<sup>3</sup> Mineral interests, especially those that are severed, are very often owned on an undivided, percentage-ownership basis.<sup>4</sup> In other words, for any one tract, the mineral estate may have several owners.<sup>5</sup>

The unfortunate result of this division is that an oil company is often unsuccessful in leasing every individual interest in every tract it intends to drill.<sup>6</sup> When the dust settles, the would-be driller commonly finds that there are small, undivided interests in its drill site tract or tracts that are unleased or, as likely, leased to a third party.<sup>7</sup>

In such a scenario, there are three options: negotiate and agree on an operating agreement, trade out, or drill on a cotenancy basis.<sup>8</sup> Executing an operating agreement is, of course, quite common and modifies the cotenancy relationship.<sup>9</sup> The operating agreement is an agreement among the parties that addresses, among other things, who will operate the well, how operations will be conducted, and how revenues and expenses will be allocated.<sup>10</sup> Trading out is a catch-all category encompassing any number of solutions, from the outright sale of one party's interest to another, farming out and reserving an override, and a possible back-in or any other of a myriad of possible deals.<sup>11</sup> Ideally, trading out will result in one party holding 100% of the leasehold of the tract of acreage in question.<sup>12</sup> Both of these scenarios, of course, require the cooperation and consent of both parties.<sup>13</sup> For instances in which the parties cannot agree to do either of the first two options, the only practical remaining course of action is either to let the leases expire or to drill on a cotenancy basis.<sup>14</sup>

While it is not uncommon for a landowner to refuse to execute a lease, a hostile cotenancy frequently results when one of the owners of an undivided interest leases to a rival company.<sup>15</sup> When both companies are genuine

---

3. *Id.* at 258.

4. *Id.* at 256.

5. *Id.*

6. See James P. Rouse, *Oil and Gas: The Necessity of Obtaining a Pooling Order before Drilling*, 31 OKLA. L. REV. 451, 452 (1978).

7. See generally *id.*

8. Kramer, *supra* note 2, at 256–63.

9. Gary Conine, *Property Provisions of the Operating Agreement—Interpretation, Validity, and Enforceability*, 19 TEX. TECH. L. REV. 1263, 1264–65 (1988).

10. See, e.g., AM. ASS'N PROF'L LANDMEN, A.A.P.L. FORM 610-1989 MODEL FORM OPERATING AGREEMENT, reprinted in JOHN S. LOWE ET AL., FORMS MANUAL TO ACCOMPANY CASES AND MATERIALS ON OIL AND GAS LAW 357 (West Publishing eds., 6th ed. 2015) [hereinafter FORM 610-1989 MODEL FORM OPERATING AGREEMENT].

11. See generally Kramer, *supra* note 2, at 259–60.

12. Cf. Rouse, *supra* note 6 (showing that, without trading out, a single unit can contain a complex patchwork of leased and unleased land).

13. See generally Kramer, *supra* note 2, at 259. See also Conine, *supra* note 9, at 1266.

14. See Kramer, *supra* note 2, at 256.

15. Cf. *Southland Royalty Co. v. Pan Am. Petroleum Corp.*, 378 S.W.2d 50, 51 (Tex. 1964) (showing that multiple oil production companies can have leases on the same tract of land).

Exploration and Production (E&P) companies, conflicts can arise where both desire to drill or operate the well.<sup>16</sup> A more-experienced driller, in a particular play, may balk at taking a non-operating position if he feels he would be funding the learning curve of a less-experienced rival.<sup>17</sup> Likewise, an experienced operator may resist allowing a rival with a small working interest to participate in the well for fear of losing a competitive advantage.<sup>18</sup> For example, paying a proportionate share of the drilling costs for a 5% or 10% working interest is, in many situations, a small price to pay for access to well logs and exposure to well-completion techniques not known or available to the general public.<sup>19</sup> One should also be careful not to overlook the role that sheer ego can often play in these circumstances. A desire to “control the play,” or a need to shut-out a perceived interloper can often prevent parties from working toward an amicable solution.<sup>20</sup>

However, just as frequently, if not more so, the rival company to which the undivided interest owner has leased is not a “genuine” E&P company.<sup>21</sup> In other words, the company that has taken the lease is not in the business of drilling or operating wells.<sup>22</sup> Rather, its business model is centered on acquiring leases and then selling them to an E&P company which is active in the play.<sup>23</sup> These so called “lease flippers” often have little or no desire to pay for the drilling of the well.<sup>24</sup> Their profit is derived from the price difference between what they paid to acquire the leases and what they receive from selling them, as well as any override they can retain as part of the sale.<sup>25</sup> Because the flipper likely had to pay above-market rates to acquire the lease in the first place (otherwise the E&P company would have likely leased it), the flipper often seeks to sell it for a hefty ransom.<sup>26</sup> The whole process often smacks of extortion and very often leads to a hostile cotenancy situation.<sup>27</sup>

More often than not, an operator will refuse to drill a well with even a small uncommitted-cotenancy interest, due to the adverse impact it will have

---

16. *See generally id.*

17. *See generally* John McArthur, *A Twelve-Step Program for COPAS to Strengthen Oil and Gas Accounting Protections*, 49 SMU L. REV. 1447, 1487 (1996).

18. *See, e.g., id.* at 1497 (discussing how more-experienced operators are better at predicting well costs).

19. *See infra* Part III (explaining the economic effects of certain types of interests on payout).

20. *See infra* Part IV (discussing potential conflicts of cotenants and strategies to cope with those potential conflicts).

21. *Identifying Speculative Deals in Oil and Gas Investing*, ENERGY FUNDERS, <https://www.energyfunders.com/speculative-deals-oil-and-gas-investing/#.Wdae3mhSxPY> (last visited Oct. 8, 2017).

22. *Id.*

23. *Id.*

24. *Id.*

25. *Id.*

26. *Tips for Managing Your Minerals and Royalties (Oil and Gas)*, HILLTOP ROYALTIES, <http://hilltoproyalties.com/blog/10-tips-for-negotiating-oil-gas-mineral-lease-texas/> (last visited Oct. 8, 2017).

27. *See generally id.*

on its revenue.<sup>28</sup> Moreover, because the issue of cotenancy drilling is often shrouded in uncertainty, an operator is typically paralyzed by his own ignorance.<sup>29</sup> Therefore, the purpose of this Article is to provide an overview of the key concepts of oil and gas estate cotenancy and the economic impact that drilling on a cotenancy basis can have on the profitability of a well. More importantly, this paper will seek to explore various strategies to mitigate the adverse revenue impacts of a hostile cotenancy-drilling scenario.<sup>30</sup> Lastly, and perhaps most importantly, it will attempt to highlight the risks inherent in pursuing such a strategy.<sup>31</sup>

## II. INTRODUCTION TO THE DOCTRINE OF COTENANCY

A cotenancy results any time two or more people concurrently own a possessory interest in the same real property.<sup>32</sup> This is different than a scenario involving two people owning two different tracts embracing the same reservoir.<sup>33</sup> A simple example of cotenancy is the hypothetical 500-acre farm of “Black Acre” owned by John Smith. John dies intestate and his two sons, Cain and Abel, inherit Black Acre. Cain and Abel each own an undivided 50% interest in Black Acre. This does not mean that Cain owns the North half and Abel owns the South half. It means that each person owns an undivided one-half of every area of real property in Black Acre.

Each cotenant has the absolute right to develop and use the land, and one cotenant may use the property without fear of owing any remuneration to the other for its rental value.<sup>34</sup> Moreover, as a general rule, one cotenant is not a trustee for the other, and no fiduciary duty is owed by one to the other.<sup>35</sup> “Each acts for himself and, absent an additional reason as by contract, neither has the authority to act for the others.”<sup>36</sup>

This is not to suggest that cotenants have *carte blanche* with the common estate.<sup>37</sup> A cotenant in possession of the estate who fails to adequately protect the property will be deemed to have committed waste, and will be liable to

---

28. See *infra* Parts III, IV (presenting the economic impacts of different tenancy situations and strategies to alleviate risks).

29. See *infra* Part IV (showing the different strategies employed to successfully drill in cotenancies and how courts are mixed in their holdings).

30. See *infra* Sections IV.A, B (presenting various strategies to reduce economic loss).

31. See *infra* Sections IV.A, B (discussing methods to mitigate loss in cotenancies).

32. 16 TEX. JUR. 3D *Cotenancy and Joint Ownership* §§ 1–2 (2013).

33. *Texon Drilling Co. v. Elliff*, 210 S.W.2d 553, 556 (Tex. Civ. App.—San Antonio 1947), *rev'd*, 146 Tex. 575 (Tex. 1948).

34. See *Cotenancy and Joint Ownership*, *supra* note 32, at § 15; see also *Fuqua v. Fuqua*, 750 S.W.2d 238 (Tex. App.—Dallas 1988, writ denied).

35. *Cotenancy and Joint Ownership*, *supra* note 32, at § 9 (citing *In re Fender*, 12 F.3d 480 (5th Cir. 1994) and other cases).

36. *Hamman v. Ritchie*, 547 S.W.2d 698, 706–07 (Tex. Civ. App.—Fort Worth 1977, writ ref'd n.r.e.).

37. See *Cotenancy and Joint Ownership*, *supra* note 32, at § 9 (citing *Eternal Cemetery Corp. v. Tammen*, 324 S.W.2d 562, 564 (Tex. Civ. App.—Fort Worth 1959, writ ref'd n.r.e)).

his cotenant for losses resulting therefrom.<sup>38</sup> In addition, “[i]t is well settled that a tenant in common cannot, without the precedent authority or subsequent ratification of his cotenants, impose an easement or dedication upon the common property in favor of a third party.”<sup>39</sup> So, for example, a cotenant may not grant a pipeline right-of-way or other easement without the express joinder of his fellow owners of the common estate.<sup>40</sup>

For instances in which a cotenant has obtained rents or profits from the common estate, he must account to the other cotenants for their share of the proceeds minus the reasonable and necessary expenses.<sup>41</sup> It must be clarified that, when proceeds or profits are referenced, it means profits derived from the common estate.<sup>42</sup> A cotenant, who runs a profitable business from an office located on the common estate, need not share in these proceeds merely by virtue of the location of his office.<sup>43</sup> However, if the cotenant established a successful hotel on the premises, for example, the profits from which would be derived from renting out the various rooms located upon the common estate, an accounting would need to be made.<sup>44</sup>

In this same vein, when one cotenant has sold timber growing on the common estate, “both the selling co-tenant and his *vendee* [become] liable to the non-selling co-tenants for their proportionate part of timber cut and removed where the timber cut was more than the selling co-tenant’s proportionate part.”<sup>45</sup>

Conversely, in instances in which a cotenant has expended funds to preserve the common estate, he may seek proportionate reimbursement from his cotenants.<sup>46</sup> So, for example, when a cotenant has made a mortgage payment or paid the property taxes, he may invoice his cotenants for their

---

38. See *Guffey v. Stroud*, 16 S.W.2d 527, 529 (Tex. 1929); *Cotenancy and Joint Ownership*, *supra* note 32, at § 26 (citing *Kirby Lumber Co. v. Temple Lumber Co.*, 83 S.W.2d 638, 642 (Tex. 1935)).

39. *Lee v. Phillips Petroleum Co.*, 329 F. Supp. 579, 582 (S.D. Tex. 1971) (citing *Heilbron v. St. Louis Sw. Royalty Co. of Tex.*, 113 S.W. 610, 613 (Tex. App.—Texarkana 1908, writ ref’d); *Chenoweth Bros. v. Magnolia Petroleum Co.*, 129 S.W.2d 446, 447 (Tex. Civ. App.—Dallas 1939, writ dism’d judgm’t cor.)).

40. *Tex. Mortg. Co. v. Phillips Petroleum Co.*, 470 F.2d 497, 499 (5th Cir. 1972) (citing *Heilbron*, 113 S.W. at 613.)

41. *Cotenancy and Joint Ownership*, *supra* note 32, at § 15 (citing *Eddings v. Black*, 602 S.W.2d 353, 358 (Tex. Civ. App.—El Paso 1980, writ ref’d n.r.e.)); *see also Williams v. Shamburger*, 638 S.W.2d 639, 640 (Tex. App.—Waco 1982, writ ref’d n.r.e.).

42. See *Potka v. Potka*, 205 S.W.2d 51, 55 (Tex. Civ. App.—Waco 1947, writ ref’d n.r.e.).

43. See *id.*

44. See, e.g., *I-10 Colony v. Lee*, 393 S.W.3d 467, 479–80 (Tex. App.—Houston [14th Dist.] 2012, pet. denied).

45. *Green v. Crawford*, 662 S.W.2d 123, 127 (Tex. App.—Tyler 1983, writ ref’d n.r.e.) (emphasis in original).

46. *Cotenancy and Joint Ownership*, *supra* note 32, at § 13 (citing *Smith v. Smith*, 777 S.W.2d 798, 800 (Tex. App.—Beaumont 1989, no writ)).

share, even to the extent of obtaining a lien on their interest in the property to compel payment.<sup>47</sup>

However, one must distinguish between improvements that are necessarily made, and improvements made speculatively.<sup>48</sup> A cotenant who incurs speculative expenses, such as exploring for oil and gas, is not entitled to reimbursement from his fellow cotenants.<sup>49</sup> However, he is entitled to recoup his reasonable and necessary expenses in drilling the well out of the proceeds of production—if and when it is achieved—upon accounting to his cotenants.<sup>50</sup> This is often referred to as a “net profits” cotenancy accounting.<sup>51</sup>

With regards to cotenancy of the mineral estate, each cotenant, regardless of the amount of interest in the land, may explore, drill, and develop oil and gas without the participation or the permission of his or her other cotenants.<sup>52</sup> The non-participating or non-consenting cotenants then have the right to receive their proportionate share of the value of any oil and gas produced, minus their proportionate share of the reasonable and necessary costs of discovery and production.<sup>53</sup>

When an oil and gas company takes a lease from an owner of an undivided interest, it has acquired a fee simple determinable in the mineral estate and steps into the shoes of its lessor for cotenancy purposes.<sup>54</sup> As such, if there is an existing lease, it is the lessee that is the cotenant to the other mineral-interest owners.<sup>55</sup> If those mineral-interest owners have leased to a different company, then the two lessee-oil companies are tenants in common of the mineral estate.<sup>56</sup>

---

47. *Stephenson v. Luttrell*, 179 S.W. 260, 263 (Tex. 1915); *Wooley v. West*, 391 S.W.2d 157, 160 (Tex. Civ. App.—Tyler 1965, writ ref'd n.r.e.); *see also* *Duke v. Squibb*, 392 S.W.2d 885, 888 (Tex. Civ. App.—Texarkana 1965, no writ).

48. *See* *Shaw & Estes v. Tex. Consol. Oils*, 299 S.W.2d 307, 313 (Tex. Civ. App.—Galveston 1957, writ ref'd n.r.e.).

49. *Neeley v. Intercity Mgmt. Corp.*, 732 S.W.2d 644, 646 (Tex. App.—Corpus Christi 1987, no writ).

50. *Byrom v. Pendley*, 717 S.W.2d 602, 605 (Tex. 1986); *Cox v. Davidson*, 397 S.W.2d 200, 201 (Tex. 1965); *Burnham v. Hardy Oil Co.*, 147 S.W. 330, 335 (Tex. Civ. App.—San Antonio 1912), *aff'd*, 108 Tex. 555 (Tex. 1917).

51. *See, e.g.*, *ConocoPhillips Co. v. Ramirez*, No. 04-15-00487-CV, 2017 WL 2457090, at \*10 (Tex. App.—San Antonio June 7, 2017, no pet.).

52. *Cox*, 397 S.W.2d at 202–03; *Burnham*, 147 S.W. at 334–35.

53. *Willson v. Superior Oil Co.*, 274 S.W.2d 947, 950 (Tex. Civ. App.—Texarkana 1954, writ ref'd n.r.e.).

54. *Glover v. Union Pac. R.R.*, 187 S.W.3d 201, 213 (Tex. App.—Texarkana 2006, pet denied) (citing *Willson*, 274 S.W.2d at 950; *Burnham*, 147 S.W. at 334).

55. *Id.*

56. *Id.*

## III. ECONOMICS

Let us return to Black Acre—our 500-acre hypothetical farm. Let us assume that Black Acre has four owners, each owning an equal, undivided interest. Lastly, let us assume that three of the four owners have agreed to lease to a large E&P company that is active in the area. For purposes of this hypothetical, let us refer to this E&P company as Big Oil, Inc. (Big Oil).

If Big Oil moves forward and drills a well on Black Acre, it does so with leases covering only 75% of the tract—the remaining 25% is an unleased cotenant.<sup>57</sup> As stated above, Big Oil is well within its rights to drill the well, but it must account to its 25% cotenant for its share of the value of oil and gas produced, minus its proportionate share of the costs (this 25% is often referred to as the “carried interest”).<sup>58</sup> Another way of stating this is that Big Oil is entitled to recoup its costs before sharing any of the revenues with the cotenant.<sup>59</sup> See the table below.<sup>60</sup>

**Chart 1: Effects of a Carried Working Interest on NRI**

Mineral Interest Owners and Company	Net Revenue Before Payout (BPO)	Net Revenue After Payout (APO)	Baseline (assuming 100% leased)
Big Oil	<b>81.25%</b> (Big Oil takes 100% of revenue minus a 25% royalty paid on 75% of the mineral estate).	<b>56.25%</b> (Big Oil takes only 75% of the revenue minus a 25% royalty paid on 75% of the mineral estate).	100% - (100%*1/4 royalty) = 75%
Royalty Owners (75% Leased)	<b>18.75%</b> (1/4 royalty on 90% of the mineral estate).	<b>18.75%</b> (1/4 royalty on 75% of the mineral estate).	75% * 1/4 royalty = 18.25%
25% Unleased	<b>[0%]</b>	<b>25%</b>	25% * 1/4 royalty = 6.25% (assuming leased)

57. *Id.*

58. *Byrom v. Pendley*, 717 S.W.2d 602, 605 (Tex. 1986); HOWARD R. WILLIAMS & CHARLES L. MEYERS, *MANUAL OF OIL AND GAS TERMS* 113–15 (Matthew Bender ed., Times Mirror Books 7th ed. 1987) (defining “carried interest”).

59. *Byrom*, 717 S.W.2d at 605.

60. Caleb Fielder, Chart 1: Effects of a Carried Working Interest on NRI (2017) (unpublished chart) (on file with author).

After the well “pays out,” Big Oil’s Net Revenue Interest (NRI), predictably, takes a ten-point drop.<sup>61</sup> Notice, however, that before the well pays out, Big Oil has a slightly inflated NRI.<sup>62</sup> This is because Big Oil is taking its share of production as well as the unleased cotenant’s share until the well pays out.<sup>63</sup>

However, this table ultimately tells us very little.<sup>64</sup> We can determine what percentage of the well’s revenue stream ends up in Big Oil’s pocket, but we cannot determine from it whether Big Oil will make any money on the venture, or how much this carried interest—or any carried interest—will impact the profitability of production on the estate.<sup>65</sup> It provides an incomplete picture in the determination of whether to drill a well with a carried interest.<sup>66</sup>

Let us assume that Big Oil is drilling a horizontal Eagle Ford well, and let us further assume that this well will produce 365,000 barrels of oil over its lifetime on a hyperbolic decline with a 0.082 initial decline and an initial month’s production of 640 barrels of oil per day.<sup>67</sup>

---

61. *Id.*

62. *Id.*

63. *Id.*

64. *Id.*

65. *Id.*

66. *Id.*

67. U.S. Energy Info. Admin., *Oil and Gas Supply Module of the National Modeling System: Model Documentation 2014*, U.S. DEP’T ENERGY, 1, 174, Table 2.C-1 Hyperbolic decline curve parameters for select tight oil plays (July 2014), [https://www.eia.gov/outlooks/aeo/nems/documentation/ogsm/pdf/m063\(2014\).pdf](https://www.eia.gov/outlooks/aeo/nems/documentation/ogsm/pdf/m063(2014).pdf) (Eagle Ford-Oil Dewitt, TX. Qi (b/d): 694, Di: 0.082, “b” factor: 0.341, IP(b/d): 640, EUR (Mbbl/well): 365).



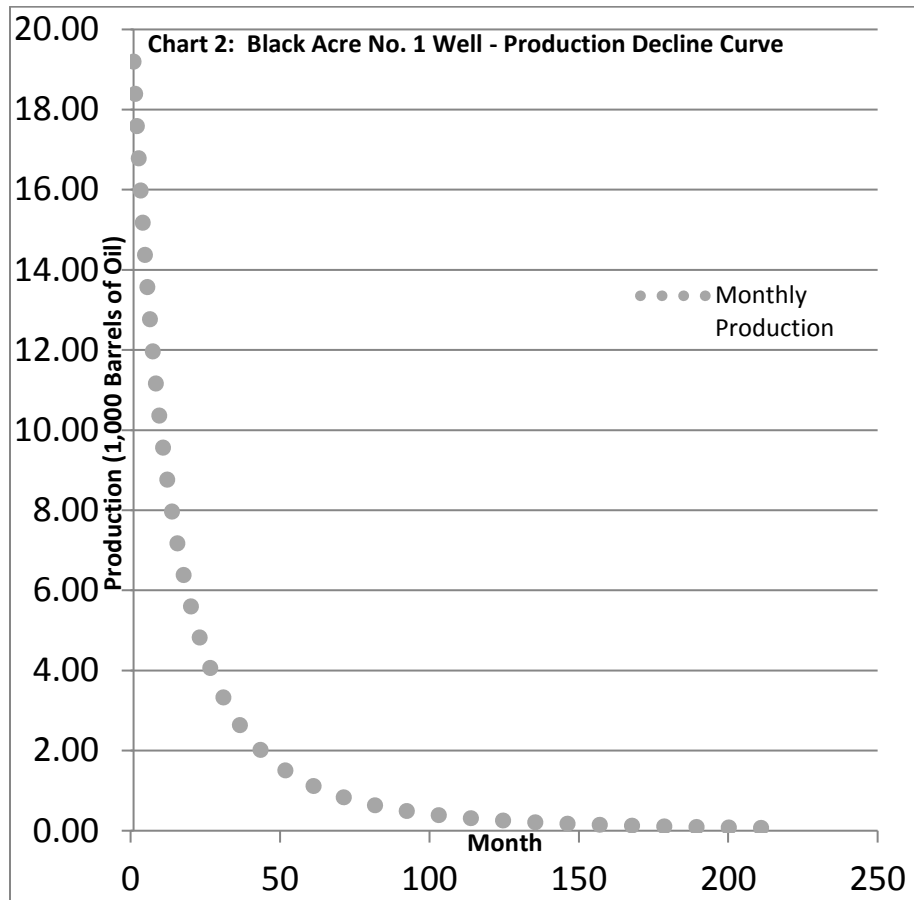
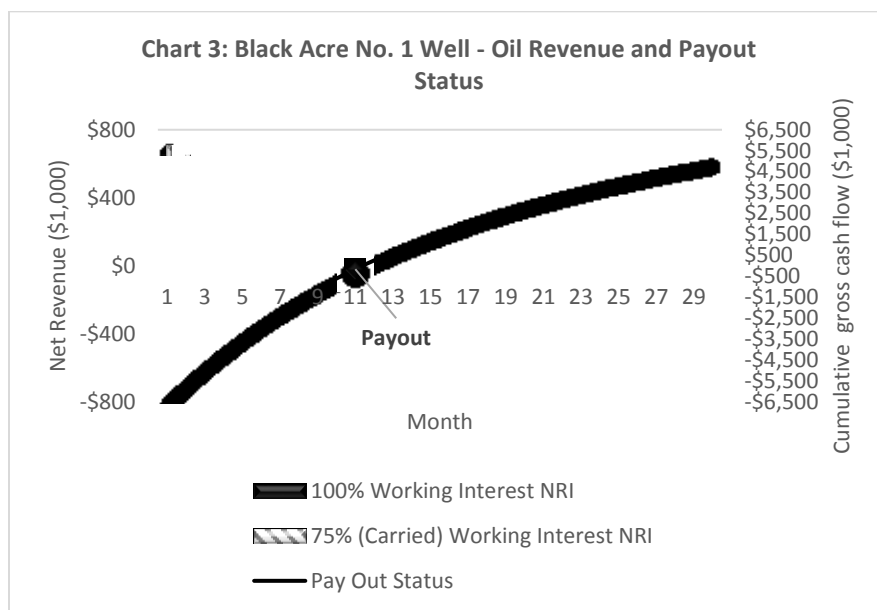


Chart 2 plots a decline curve of this hypothetical well, which shall be referred to as the “Black Acre No. 1.”<sup>68</sup> As is typical of shale oil production, there is a very steep production decline; most of the production from this well will be obtained early in its life.<sup>69</sup>

68. *Id.* at 173, Appendix 2.C (formula for decline curve hyperbolic function:  $Q_t = Q_i / [(1 + b * D_i * t)^{1/b}]$ , where  $Q_t$  = Production in month  $t$ ,  $Q_i$  = Production rate at time 0,  $b$  = Hyperbolic parameter,  $D_i$  = Initial decline rate,  $t$  = Month in production). This has been reproduced via Excel spreadsheet with the following formula:  $Q_i * (1 + b * D_i * t)^{-1/b}$ . Production was calculated on a monthly basis with an assumed production life of 221 months. Caleb Fielder, Chart 2: Black Acre No. 1 Well - Production Decline Curve (2017) (unpublished table) (on file with author).

69. *See generally* U.S. Energy Info. Admin., *supra* note 67, at 173. An analysis of oil production decline curves is obviously well outside the scope of this paper. The point of including this is to provide a baseline understanding of how shale production profiles impact the amount and timing of the production. This has a direct impact on revenues and provides needed context for any examination on the profitability of a well and the effects of a carried interest thereon.

If it costs Big Oil \$6.5MM to drill, complete, and equip the well,<sup>70</sup> and the price of oil is forty-five dollars per barrel,<sup>71</sup> it will take approximately eleven months for the well to reach payout.<sup>72</sup> Reference is made to Chart 3.<sup>73</sup> Payout means “the recovery from production of costs of drilling and equipping a well.”<sup>74</sup> Moreover, this production is gross, not net, as an unleased cotenant’s share of net profits is not burdened by Big Oil’s royalty payments.<sup>75</sup> Put another way, after Big Oil spends \$6.5MM, it will take eleven months of production for the cumulative cash flow associated with the well to reach zero.<sup>76</sup>



However, the introduction of a carried interest alters Big Oil’s NRI. As noted in Chart 1, Big Oil’s before-payout (BPO) NRI is inflated by the

70. U.S. Energy Info. Admin., *Trends in U.S. Oil and Natural Gas Upstream Costs*, U.S. DEP’T ENERGY 1, 20, § E. Future Cost Trends (Mar. 2016), <https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf> (outlining Eagle Ford 2015 projected well costs).

71. For the sake of simplicity, \$45 per barrel is assumed to be Big Oil’s realized price, including any costs associated with gathering, marketing, transportation, quality, etc.

72. See Caleb Fielder, Chart 3: Black Acre No. 1 Well - Oil Revenue and Payout Status (2017) (unpublished chart) (on file with author).

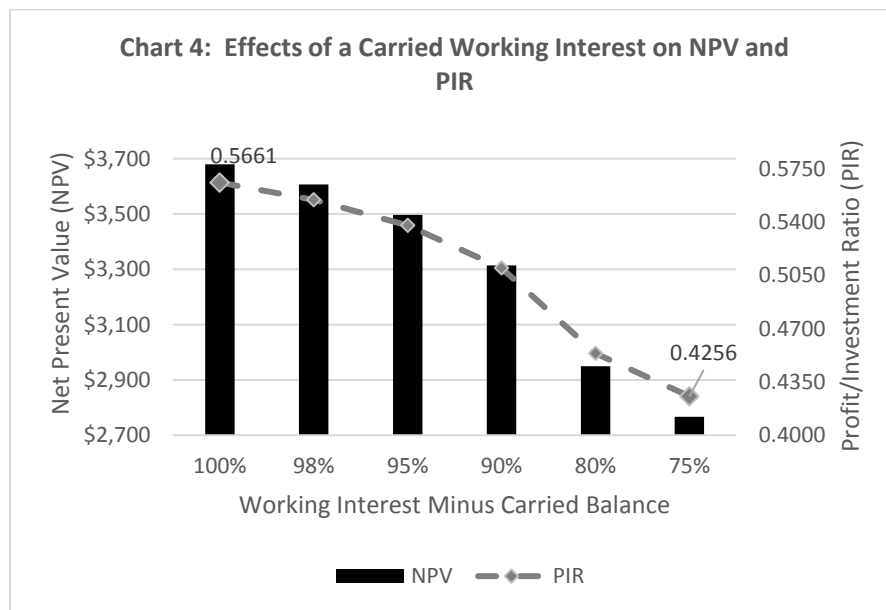
73. *Id.* It is important to note that the revenues depicted are net of royalty payments, while the gross cash flow does not account for royalty payments.

74. WILLIAMS & MEYERS, *supra* note 58, at 696 (defining “pay out”); see also Stable Energy, L.P. v. Newberry, 999 S.W.2d 538, 543 n.2 (Tex. App.—Austin 1999, pet. denied) (noting that payout is reached when costs of drilling and equipping the well are recovered from production).

75. ConocoPhillips Co. v. Ramirez, No. 04-15-00487-CV, 2017 WL 2457090, at \*14 (Tex. App.—San Antonio June 7, 2017, no pet.).

76. See *supra* text accompanying notes 70–74 (showing that it will take eleven months for the well to reach payout).

amount of the carried interest.<sup>77</sup> Thus, Big Oil's revenue from the well is artificially—though temporarily—boosted.<sup>78</sup> As depicted in Chart 3, as soon as the well pays out, the cotenant begins taking his share of proceeds from production.<sup>79</sup> Big Oil has recouped the reasonable and necessary costs of the well and must now account to its cotenant.<sup>80</sup> Big Oil's revenue from the well drops precipitously at this point and, with it, the overall value of the well.<sup>81</sup> Under a best case (100% working interest) scenario, the Black Acre No. 1 well has a present value (10%) to Big Oil of approximately \$10.18MM.<sup>82</sup> This represents a profit of about \$3.68MM.<sup>83</sup>



77. See Chart 1, *supra* note 60; see also *supra* text accompanying notes 62–63 (stating that Big Oil's NRI is slightly inflated because Big Oil is taking its share of production as well as the unleased cotenant's share).

78. See *supra* text accompanying notes 61–63 (stating that Big Oil takes its share of production as well as the unleased cotenant's share until the well pays out).

79. *Byrom v. Pendley*, 717 S.W.2d 602, 605 (Tex. 1986); see Chart 1, *supra* note 60.

80. *Byrom*, 717 S.W.2d at 605.

81. See *supra* text accompanying notes 60–61 (illustrating the drop in NRI).

82. See *Present Value*, BLACK'S LAW DICTIONARY 1222 (Bryan A. Garner ed., 8th ed. 2004) (defining present value as, "[t]he sum of money that, with compound interest, would amount to a specified sum at a specified future date; future value discounted to its value today"). In this context, the compound interest is set (somewhat arbitrarily) at 10%, and the specified sum and date correspond to the particular revenue from the well during a particular month. See Caleb Fielder, Chart 4: Effects of a Carried Working Interest on NPV and PIR (2017) (unpublished chart) (on file with author). However, it must be noted that payout determinations are made with nominal ("dollars of the day") figures, not present value calculations.

83. See Chart 4, *supra* note 82. \$10.18MM PV - \$6.5MM well cost = a profit of \$3.68MM. See *id.* It must be stressed that these figures, like all other figures in this paper, are pre-tax.

Therefore, if Big Oil invested \$6.5MM in order to make a profit of \$3.68MM, its Profit to Investment Ratio (PIR), a key metric in determining where and whether to invest capital, is just over 0.56.<sup>84</sup> As seen on Chart 4, Big Oil's PIR steadily declines as its carried interest increases.<sup>85</sup>

As noted, the PIR metric is used to determine where and whether to invest capital.<sup>86</sup> If Big Oil's only objective is to make a profit—any profit—it may be willing to drill this well with a very high carried interest.<sup>87</sup> However, if Big Oil can get a higher return for its money by drilling elsewhere, it is only logical for Big Oil to do so. Thus, under this scenario, if Big Oil's alternate drilling prospects would only yield a PIR of 0.40, Big Oil might be very willing to drill this well with a 25% carried interest (or more).<sup>88</sup> If, however, Big Oil's alternate drilling prospects would yield a PIR of 0.50, Big Oil could only rationally drill this well with no more than a 10% carried interest.<sup>89</sup>

Ultimately, Big Oil wants to drill the most profitable well that it can, and the existence of an unleased or an otherwise leased cotenant is retrograde to that desire. Dealing with, and mitigating the damage from, the carried interest is the central theme of this Article.

#### IV. STRATEGY

If Big Oil has exhausted its efforts to lease or otherwise acquire the carried interest, its options are limited. An amicable solution is likely out of reach, as the relationship between the cotenants has turned inimical. If Big Oil is determined to produce Black Acre, it may warrant pursuing more aggressive tactics. This Section explores some possible strategies to alleviate the risk and economic impact implicated in such an aggressive cotenancy development of the mineral estate.

##### *A. Partition*

In instances in which the uncontrolled portion of the tract is unleased, where the outstanding interest is too large to profitably carry, or top leasing is impossible or impractical, the only remaining avenue is partition.<sup>90</sup> While a lengthy, technical, and potentially expensive endeavor, a partition action holds the potential of segregating the participating and nonparticipating

---

84. *Id.*

85. *Id.*

86. *Id.*

87. *Id.*

88. *Id.*

89. *Id.*

90. See, e.g., Dorothy J. Glancy, *Breaking Up Can Be Hard to Do: Partitioning Jointly Owned Oil and Gas and Other Mineral Interests in Texas*, 33 TULSA L.J. 705, 720 (1998).

cotenants' undivided ownership.<sup>91</sup> A partition in kind would physically allocate a separate portion of the estate to each cotenant depending on his undivided ownership and subject to a balance of equities; thus, allowing Big Oil to drill its well on its partitioned portion of the property without the need to carry or account to the nonparticipant.<sup>92</sup>

Partition in Texas is afforded both in equity and by statute and is a right granted to any owner of a possessory interest in real property.<sup>93</sup> The Texas Property Code states, in pertinent part, that “[a] joint owner . . . of real property or an interest in real property . . . may compel a partition of the interest or the property among the joint owners . . . .”<sup>94</sup> The courts have made it clear that only the owner of a possessory interest qualifies under this statute and may compel partition.<sup>95</sup> Owners of reversionary or royalty interests cannot compel partition and are not necessary parties to a partition action.<sup>96</sup> Because an oil company that takes an oil and gas lease has acquired a fee simple determinable in the mineral estate—a possessory interest—it may pursue a partition action related to the mineral estate.<sup>97</sup>

However, seeking partition carries a number of risks—most notably, in terms of the time it may take.<sup>98</sup> Big Oil runs the risk of its leases expiring before a partition is finalized.<sup>99</sup> Equitable partition, widely considered the quicker and less cumbersome method, can take years.<sup>100</sup> A statutory partition in kind has the potential to take even longer, as it requires two jury trials, each of which is subject to appeal as well as the appointment and subsequent determination of commissioners who must complete the partition.<sup>101</sup>

Also, depending on the circumstances, it is possible for a court to determine that the common estate is not susceptible to partition in kind; thus, resulting in a partition by sale in which the drilling party risks losing the very acreage it seeks to develop.<sup>102</sup> Cases involving the forced partition<sup>103</sup> of the mineral estate are relatively sparse.<sup>104</sup> As a general rule in partitioning real property, Texas courts favor partition in kind when it is equitable to do so, as

---

91. See generally *id.* at 720–54.

92. See *id.* (discussing possessory and title consequences of partition in kind of the mineral estate).

93. TEX. PROP. CODE ANN. § 23.001 (West 2017); TEX. R. CIV. P. 776.

94. TEX. PROP. § 23.001.

95. See *Henderson v. Chesley*, 273 S.W. 299, 304 (Tex. Civ. App.—Texarkana 1925, writ denied).

96. *Tex. Oil & Gas v. Ostrom*, 638 S.W.2d 231, 234–35 (Tex. App.—Tyler 1982, writ ref'd n.r.e.).

97. *Id.*

98. See generally *Mapco, Inc. v. Carter*, 817 S.W.2d 686 (Tex. 1991).

99. See, e.g., *id.* at 688 (illustrating an action for equitable partition that took over three years, including two appellate court decisions and a decision by the Texas Supreme Court); see also *Glancy*, *supra* note 90, at 740 (describing the Texas partition process as lengthy).

100. See, e.g., *Mapco, Inc.*, 817 S.W.2d at 688.

101. TEX. R. CIV. P. 756–71; see also *Glancy*, *supra* note 90, at 736.

102. TEX. R. CIV. P. 770; see, e.g., *White v. Smyth*, 214 S.W.2d 967, 974 (Tex. 1948).

103. By “forced partition,” the Author seeks merely to distinguish the court ordered partitions from those in which cotenants or heirs to an estate voluntarily partition the common property.

104. See *Glancy*, *supra* note 90, at 740 n. 207.

opposed to a sale of the property with division of the proceeds.<sup>105</sup> An in-kind partition also has the added benefit of not disrupting an intended form of inheritance or forcing a person to unwillingly sell his property which “should not be done except in cases of imperious necessity.”<sup>106</sup>

Regarding the mineral estate, there is authority that “the general rule [is] that known mineral lands, because of elements of uncertainty, not resolvable at reasonable cost, are not susceptible of fair division by metes and bounds . . . .”<sup>107</sup> In other words, where “there has been no development or exploration [of] minerals” on a given tract, it is presumed to be an “unknown” mineral land, and any minerals are presumed to be evenly distributed.<sup>108</sup> Tracts that have been subject to development (known mineral lands)—or tracts in the vicinity of production—then are afforded no such presumption of even distribution—hence, the oft-referenced “general rule” that they are not susceptible to a partition in kind.<sup>109</sup>

Thus, Big Oil is potentially tossed upon the horns of a dilemma. It may choose to delay drilling in an effort to preserve Black Acre’s status as an unknown mineral land, pursue partition and run the risk that its leases expire before the partition is concluded; or it can drill, allowing it to hold its leases but thereby designating Black Acre as a known mineral land and imperiling its ability to obtain a partition in kind.<sup>110</sup>

However, it must be stressed that the question of whether a particular mineral estate is susceptible to partition in kind is one of fact, not law, and there are numerous appellate court decisions upholding a trial court’s determination of partition in kind of known mineral lands.<sup>111</sup> All of these exceptions have eviscerated the general rule, if there ever was one.<sup>112</sup> Indeed, “[i]t is presumed, in the absence of proof to the contrary, that minerals are equally distributed and that a partition-in-kind will not result in an inequitable

105. *Henderson v. Chesley*, 273 S.W. 299, 303 (Tex. Civ. App.—Texarkana 1925, writ denied); see also TEX. R. CIV. P. 770 (“Should the court be of the opinion that a fair and equitable division of the real estate, or any part thereof, cannot be made, it shall order a sale of so much as is incapable of partition . . . .”).

106. *Robertson v. Robertson*, 425 S.W.2d 707, 708 (Tex. Civ. App.—Houston [14th Dist.] 1968, no writ) (quoting 68 C.J.S. *Partition* § 125 (2017)).

107. *White*, 214 S.W.2d at 973 (citing multiple out of state cases as well as *Summers’ Oil and Gas* and other secondary sources).

108. *Henderson*, 273 S.W. at 303.

109. See *White*, 214 S.W.2d at 973–75; Glancy, *supra* note 90, at 725.

110. See *White*, 214 S.W.2d at 973–75.

111. See, e.g., *Daven Corp. v. Tarh E&P Holdings*, 441 S.W.3d 770, 777 (Tex. App.—San Antonio 2014, pet. denied); *Champion v. Robinson*, 392 S.W.3d 118, 123 (Tex. App.—Texarkana 2012, pet. denied); *Irons v. Fort Worth Sand & Gravel Co.*, 284 S.W.2d 215, 220 (Tex. Civ. App.—Fort Worth 1955, writ ref’d n.r.e.); *Outlaw v. Bowen*, 285 S.W.2d 280, 286 (Tex. Civ. App.—Amarillo 1955, writ ref’d n.r.e.); *Amerada Petroleum Corp. v. Massad*, 239 S.W.2d 730, 734 (Tex. Civ. App.—El Paso 1950, no writ); *Humble Oil Ref. v. Lasseter*, 95 S.W.2d 730, 731 (Tex. Civ. App.—Texarkana 1936, writ dism’d w.o.j.).

112. See *Daven Corp.*, 441 S.W.3d at 777; *Champion*, 392 S.W.3d at 123.

distribution of the mineral estate.”<sup>113</sup> In addition, because there is a preference for in-kind partition over partition by sale, “[t]he party opposing the partition-in-kind has the burden to prove that the property is not subject to a fair division and is thus incapable of partition-in-kind.”<sup>114</sup> Moreover, there is ample authority that, where a cotenant has made improvements on the common estate, it may warrant the award of the particular improved portion of the property to the improving cotenant.<sup>115</sup>

It would therefore be plausible—though nonetheless risky—for Big Oil to drill a well on Black Acre and then seek partition in kind in an attempt to obtain a 75% divided interest of the tract encompassing the Black Acre No. 1 well.<sup>116</sup> Indeed, the ubiquity of shale production in the vicinity of many known mineral lands, coupled with the assembly-line-like methodology of pad drilling, could play a decisive role in determining that a known mineral estate—while containing elements of uncertainty—is nonetheless homogenous enough to warrant partition in kind.

### B. Top Lease

The greatest opportunity for increased profitability is found in those circumstances in which the uncontrolled or “carried” interest has been leased to a third party, such as a lease flipper or a rival E&P company.<sup>117</sup> As a general proposition, such a third party will be unable to rely on Big Oil’s drilling activity to perpetuate its lease.<sup>118</sup>

A typical habendum clause in a “standard lease” will state that “this Lease shall be for a term of \_\_\_ years from this date (called ‘primary term’) and as long thereafter as oil and gas or other hydrocarbons are being produced from said land or land with which said land is pooled hereunder.”<sup>119</sup> As such, and as most oil and gas professionals are aware, an operator may perpetuate the life of such a lease beyond its primary term only by production in paying quantities (or the performance of related operations) or by some sort of savings clause, such as a shut-in royalty clause, cessation of production

---

113. *Daven Corp.*, 441 S.W.3d at 777 (citing *Champion*, 392 S.W.3d at 125).

114. *Id.* (citing *Champion*, 392 S.W.3d at 123; *Adams v. Adams*, 205 S.W.2d 801, 803 (Tex. Civ. App.—Waco 1947, no writ)).

115. *See Price v. Price*, 394 S.W.2d 855, 858 (Tex. Civ. App.—Tyler 1965, writ ref’d n.r.e.); *see also*, e.g., *Snow v. Donelson*, 242 S.W.3d 570, 572 (Tex. App.—Waco 2007, no pet.).

116. *Cf. Price*, 394 S.W.2d at 858 (discussing improved portions being assigned to the improver in a partition in kind).

117. *See Hughes v. Cantwell*, 540 S.W.2d 742, 743–44 (Tex. Civ. App.—El Paso 1976, writ ref’d n.r.e.).

118. *See id.*

119. *See, e.g.*, AM. ASS’N PROF’L LANDMEN, FORM 675 OIL AND GAS LEASE, *reprinted in* JOHN S. LOWE ET AL., FORMS MANUAL TO ACCOMPANY CASES AND MATERIALS ON OIL AND GAS LAW 101 (West Publishing eds., 6th ed. 2015) [hereinafter FORM 675 OIL AND GAS LEASE].

clause, for example.<sup>120</sup> However, such a “standard” oil and gas lease requires that the lessee perform (that is, drill or produce) either directly or constructively as provided in the lease to perpetuate it past the primary term.<sup>121</sup> “[T]hroughout the lease . . . the obligations which must be performed [in order to keep the lease alive] are specifically assigned to the Lessee.”<sup>122</sup>

Because these are solely the lessee’s obligations, and because the lessee has the exclusive control of the undivided interest of the mineral estate covered by the lease, “acts of third parties or strangers to the contract [will] not suffice to meet his requirements of performance.”<sup>123</sup> In other words, to perpetuate a lease past its primary term (or to excuse the payment of delay rentals as the case may be) the lessee must commence operations for drilling, cause said operations to commence (for example, by a farmout), or participate and pay his fair share of said drilling (for example, in the context of an operating agreement).<sup>124</sup> This reasoning—that drilling by the lessee of another undivided interest in the same tract of land will not perpetuate a lease past its primary term—has been followed in a number of other jurisdictions, including Oklahoma,<sup>125</sup> Mississippi,<sup>126</sup> and North Dakota,<sup>127</sup> as well as the Fifth Circuit.<sup>128</sup>

As such, in a hostile cotenancy context, wherein Big Oil has drilled a well on our hypothetical 500-acre tract on which another party owns a lease covering an undivided interest on said tract, Big Oil’s drilling and subsequent production will hold Big Oil’s leases, but it will not, absent specific lease language to the contrary, hold the leases of the non-participating party in the absence of an operating agreement or farmout.<sup>129</sup>

In other words, at the end of the third-party lease’s primary term, the lease expires.<sup>130</sup> This would appear to be the case even if the well has already paid out and the third-party lessee has been sharing in the proceeds of the well.<sup>131</sup> Upon expiration, possession of the mineral estate, as to that undivided interest, reverts back to the mineral owner.<sup>132</sup> This mineral owner—now a cotenant in the mineral estate—would begin sharing in the

---

120. See, e.g., *Hydrocarbon Mgmt. v. Tracker Expl.*, 861 S.W.2d 427, 432 (Tex. App.—Amarillo 1993, no writ).

121. See *Hughes*, 540 S.W.2d at 743.

122. *Id.* at 744.

123. *Id.*

124. See *id.*

125. See generally *Buckles v. Wil-Mc Oil Corp.*, 585 P.2d 1360 (Okla. 1978); *Earp v. Mid-Continent Petroleum Corp.*, 27 P.2d 855 (Okla. 1933).

126. See generally *Wagner v. Mounger*, 175 So. 2d 145 (Miss. 1965).

127. See *Schank v. N. Am. Royalties*, 201 N.W.2d 419, 423 (N.D. 1972).

128. See *Mattison v. Trotti*, 262 F.2d 339, 341 (5th Cir. 1959).

129. See *Hughes*, 540 S.W.2d at 744.

130. *Id.*

131. See *Earp v. Mid-Continent Petroleum Corp.*, 27 P.2d 855, 867 (Okla. 1933).

132. See, e.g., *Prize Energy Res. v. Cliff Hoskins, Inc.*, 345 S.W.3d 537, 546 (Tex. App.—San Antonio 2011, no pet.).



proceeds of production.<sup>133</sup> Unless, of course, Big Oil has previously obtained a top lease from that mineral owner.<sup>134</sup>

A top lease is “[a] lease granted by a landowner during the existence of a recorded mineral lease which is to become effective if and when the existing lease expires or is terminated.”<sup>135</sup> While at one point derided as an “invidious” practice,<sup>136</sup> top leasing has long been considered an accepted and widely used business practice in the oil and gas industry.<sup>137</sup> Moreover, where mineral interest owners have already expressed a willingness to lease their interests to a third party (as opposed to refusing to lease at all), they are much more likely to agree to a top lease, if for no other reason than because it is more bonus money in their pockets.<sup>138</sup>

The basic function of the top lease is to put the top lessee “next-in-line” in the event the existing lease terminates, or is ultimately held to have terminated. The goal is to tie-up the mineral interest owner’s development rights before other competitors, including the existing lessee, have a chance to get a lease.<sup>139</sup>

Therefore, under a scenario as described above, in which Big Oil has drilled a well on a tract on which another party owns a lease, and Big Oil has “topped” that other party’s lease, Big Oil’s drilling and subsequent production will not perpetuate the competitor’s lease.<sup>140</sup> The competitor’s lease will expire, and upon expiration, Big Oil’s top lease shall vest and be held by Big Oil’s already existing operations and production.<sup>141</sup>

Such a tactic, if successful, has enormous implications for an operator’s PIR.<sup>142</sup> See Chart 5, below, which depicts the impact of a top lease that vests three years after a well has started to produce.<sup>143</sup>

---

133. *Id.* at 551.

134. *See, e.g.,* David E. Pierce, *Effective Top Leasing and Mysteries of the Habendum Clause*, 26 OKLA. BAR ASS’N MIN. LAW SEC. NEWSL. Vol. XXVI, No. 2, 2 (2005), <http://washburnlaw.edu/profiles/faculty/activity/fulltext/pierce-david-200526oklahomabarassociationminerallawnewsletter2.pdf>.

135. WILLIAMS & MEYERS, *supra* note 58, at 1011.

136. *See* Frankfort Oil Co. v. Snakard, 279 F.2d 436, 445 n.23 (10th Cir. 1960).

137. *See* Pierce, *supra* note 134.

138. *See generally id.* Typically, anywhere from 10% to 50% of a top lease bonus is paid up front with the balance coming due if and when the top lease vests. *See generally id.*

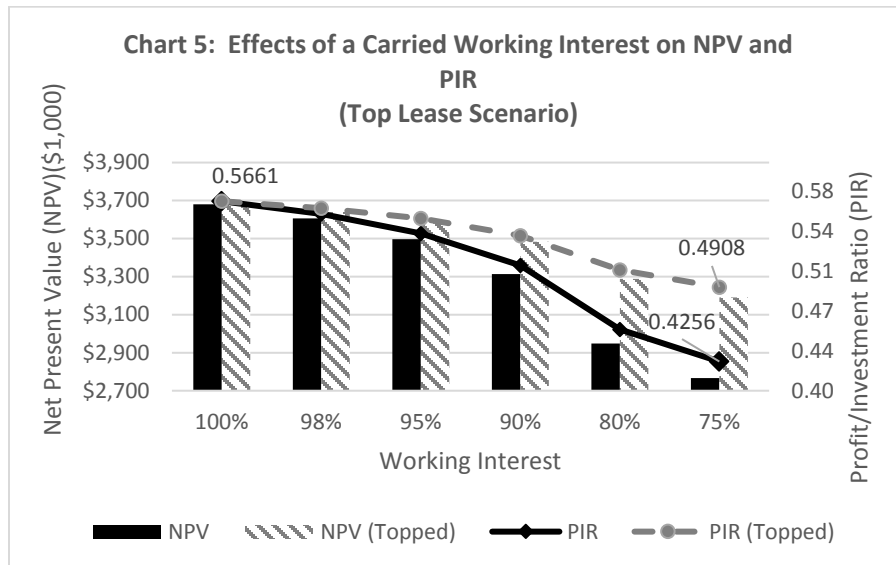
139. *Id.* at 2.

140. *Id.*

141. *Id.* at 3.

142. *See* Caleb Fielder, Chart 5: Effects of a Carried Working Interest on NPV and PIR (Top Lease Scenario) (2017) (unpublished chart) (on file with author).

143. *Id.*

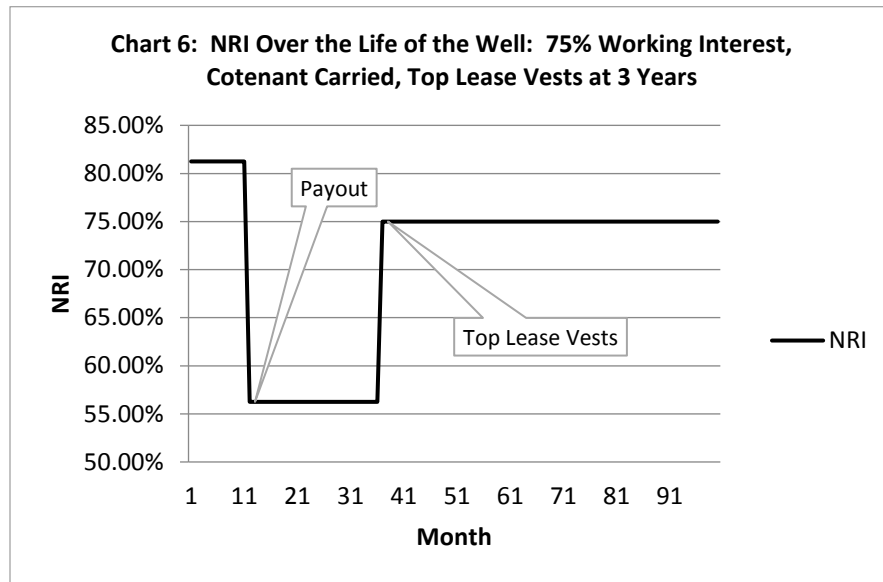


The burden of the carried interest is substantially mitigated under this scenario.<sup>144</sup> Three years is a typical primary term length, and usually, in such circumstances, a significant amount of time has lapsed between the execution of the third-party lease and the date of first production from the well.<sup>145</sup> As a general rule, the quicker the top lease vests, the higher the resulting PIR. See Chart 6 below for a graphic illustration of the NRI over the life of our Black Acre No. 1 well with a 25% carried interest when the top lease scenario is applied.<sup>146</sup>

144. *See id.*

145. *See generally* Anadarko Petroleum Corp. v. Thompson, 94 S.W.3d 550 (Tex. 2002) (stating that a typical habendum clause includes a relatively short primary term).

146. Caleb Fielder, Chart 6: NRI Over the Life of the Well: 75% Working Interest, Cotenant Carried, Top Lease Vests at 3 Years (2017) (unpublished chart) (on file with author).



The BPO NRI is inflated, as noted above, then upon payout (month eleven), the NRI drops precipitously as the third-party lessee or cotenant begins to share in the proceeds of the well.<sup>147</sup> At the beginning of month thirty-seven, however, the top lease vests, and the well's NRI jumps to 75% (100% working interest minus 25% royalty of all leases).<sup>148</sup>

The mitigating effects of this tactic are pronounced.<sup>149</sup> Even when a top lease would not vest until five years after the well began producing, our hypothetical Eagle Ford well, with a 25% carried interest, would still have a PIR of .4534 versus a .4256 PIR without the top lease.<sup>150</sup>

As can be inferred from a close observation of Chart 6, a top lease that would have vested at the beginning of month twenty-seven would have caused an NRI spike that much sooner and resulted in an even higher PIR and NPV.<sup>151</sup> In this manner, it is theoretically possible to have a more profitable well in the event an operator is forced to carry a third party.<sup>152</sup>

147. *Id.*

148. *Id.*

149. *Id.*

150. See *supra* notes 67–68 and accompanying text (providing numerical information for the hypothetical situation using data from Eagle Ford).

151. See Chart 6, *supra* note 146.

152. See *id.*

## V. ACCOUNTING: NECESSARY AND REASONABLE EXPENSES

The single greatest drawback to drilling on a cotenancy basis is that the drilling party must bear all of the risk.<sup>153</sup> If the drilling activities result in a dry hole, the operating cotenant cannot recoup any of those expenses.<sup>154</sup> Funds expended for drilling can only be recouped from production revenue if and when it is obtained.<sup>155</sup> Even then, expenses can only be recouped to the extent that they are reasonable and necessary.<sup>156</sup>

Texas courts have long held that when accounting to a cotenant, the drilling party may recoup reasonable and necessary expenses.<sup>157</sup> However, this doctrine (if it can be called that) has been applied differently by different courts.<sup>158</sup> The doctrine calls for a balancing of equities, and ultimately the actual determination of whether a particular expense is reasonable and necessary is a question of fact often decided by a jury.<sup>159</sup> Therefore, it can be difficult to predict with certainty which expenses will be allowed.<sup>160</sup> As courts have wrestled with the issue over the course of the past century, a formula—albeit nebulous—has started to emerge.<sup>161</sup>

The doctrine was first articulated by a Texas court in 1912 in *Burnham v. Hardy Oil*.<sup>162</sup> The owners of undivided interests in the mineral estate have the right “to go upon the land and extract the oil . . . subject to accounting to the other for the net proceeds thereof, which means the value of the oil taken by each, less the necessary and reasonable cost of producing it.”<sup>163</sup> In arriving at its conclusion, the court noted, “[w]ith reference to the producing wells, what is allowed the working cotenant, when called to account by another cotenant, is all expenses necessarily incurred by him in good faith in producing and rendering the product available.”<sup>164</sup> The doctrine was later expressly adopted by the Texas Supreme Court in the 1948 decision *White v. Smyth*.<sup>165</sup>

It is worth pointing out that, in accounting to a cotenant, courts have explicitly stated that cotenants must receive the net profits.<sup>166</sup> As such, the

---

153. *Cotenancy and Joint Ownership*, *supra* note 32, at § 20; *see also*, e.g., *Neeley v. Intercity Mgmt. Corp.*, 732 S.W.2d 644, 646 (Tex. App.—Corpus Christi 1987, no writ).

154. *Cotenancy and Joint Ownership*, *supra* note 32, at § 20.

155. *Neeley*, 732 S.W.2d at 646.

156. *Id.* at 647–48.

157. *See generally* *Byrom v. Pendley*, 717 S.W.2d 602 (Tex. 1986).

158. *See supra* Part V.

159. *See, e.g.*, *White v. Smyth*, 214 S.W.2d 967, 979 (Tex. 1948) (balancing these equities in an attempt to determine which expenses are reasonable and necessary).

160. *Id.*

161. *See Burnham v. Hardy Oil Co.*, 147 S.W. 330, 334–35 (Tex. Civ. App.—San Antonio 1912), *aff'd*, 195 S.W. 1139 (Tex. 1917).

162. *Id.*

163. *Id.*

164. *Id.*

165. *White*, 214 S.W.2d at 297–99.

166. *See, e.g., id.*

drilling cotenant cannot simply demand that the nonparticipant take his share of production in kind; such an imposition would no doubt be a tempting measure in an aggressive cotenancy scenario.<sup>167</sup>

Allowing a co-tenant to tender gas in-kind at the wellhead is inconsistent with Texas cotenancy law which provides that “a cotenant who produces minerals from common property without having secured the consent of his cotenants is accountable to them on the basis of the value of the mineral taken less the necessary and reasonable cost of producing and marketing the same.”<sup>168</sup>

### A. Categorical Exceptions

#### 1. Dry Holes

*Burnham*, therefore, provided the skeletal framework for the doctrine, defining “net proceeds” as the value of oil and gas less the necessary and reasonable expenses.<sup>169</sup> In addition, the opinion specifically indicates that expenses are allowed against “producing wells,” prompting inferences that costs may not be recouped for dry holes.<sup>170</sup> Such inferences manifested in later appellate case law, providing a categorical exception to the formula.<sup>171</sup> Dry hole expenditures, as a matter of law, are excluded from the accounting.<sup>172</sup>

It is worth pointing out that no Texas Supreme Court case has expressly stated that dry hole costs are not recoupable.<sup>173</sup> However, the volume of appellate court cases, combined with numerous treatises which espouse the position, would establish that it is all but settled law in Texas.<sup>174</sup> Cases subsequent to *Burnham* have amplified the justification for this exclusion.<sup>175</sup> Drilling for oil and gas is a speculative endeavor undertaken at a cotenant’s

---

167. *Prize Energy Res., L.P. v. Cliff Hoskins, Inc.*, 345 S.W.3d 537, 566 (Tex. App.—San Antonio 2011, no pet.).

168. *Id.* (citing *Cox v. Davison*, 397 S.W.2d 200, 201 (Tex. 1965)).

169. *Burnham*, 147 S.W. at 335.

170. *Id.*

171. *See Wagner & Brown, Ltd. v. Sheppard*, 198 S.W.3d 369, 378 (Tex. App.—Texarkana 2006), *rev’d on other grounds*, 282 S.W.3d 419 (Tex. 2008); *Neeley v. Intercity Mgmt. Corp.*, 732 S.W.2d 644, 646 (Tex. App.—Corpus Christi 1987, no writ); *Willson v. Superior Oil Co.*, 274 S.W.2d 947, 950 (Tex. Civ. App.—Texarkana 1954, writ ref’d n.r.e.).

172. *See Wagner & Brown, Ltd.*, 198 S.W.3d at 378; *Neeley*, 732 S.W.2d at 646; *Willson*, 274 S.W.2d at 950.

173. *See generally Cabot Oil & Gas Corp. v. Healey, L.P.*, No. 12-11-00236-CV, 2013 WL 1282007, at \*17 (Tex. App.—Tyler Mar. 28, 2013, pet. denied) (discussing the different appellate interpretations of handling dry hole expenditures).

174. *See, e.g., Wagner & Brown, Ltd.*, 198 S.W.3d at 378; *Neeley*, 732 S.W.2d at 646; *Willson*, 274 S.W.2d at 950; Marla E. Mansfield, *A Tale of Two Owners: Real Property Co-Ownership and Mineral Development*, 43 ROCKY MTN. MIN. L. INST. 20-1, 20.01 (1997).

175. *See Wagner & Brown, Ltd.*, 198 S.W.3d at 378; *Neeley*, 732 S.W.2d at 646; *Willson*, 274 S.W.2d at 950.

own risk; the operating cotenant cannot seek reimbursement for an unsuccessful venture.<sup>176</sup>

The question of whether a particular expense is tied to production or can be discarded by virtue of its lack of success is a recurring theme in the ongoing development of this doctrine as will be seen.

## 2. Interest

In *Cox v. Davison*, the drilling party, in accounting to his cotenant, sought a recoupment in the form of a 6% interest on the money expended for the cotenant's proportionate share of drilling the well.<sup>177</sup> The nonconsenting cotenants owned a three thirty-seconds interest in the common estate.<sup>178</sup> The drilling cotenants, in addition to recouping the funds expended to drill and complete the well, sought an additional credit of 6% per annum of three thirty-seconds of these funds.<sup>179</sup>

Both the trial and appellate courts allowed the recoupment.<sup>180</sup> The Texas Supreme Court, however, reversed and concluded that the producing cotenants take nothing.<sup>181</sup> "Interest is an incident of debt and is not payable in the absence of an obligation binding one person to pay money to another."<sup>182</sup> Interest, therefore, is not a recoupable cost of production.<sup>183</sup>

## 3. Workovers, Frac Jobs, and Other Wellbore Operations

Exploring for and producing oil and gas is a speculative endeavor and, absent a prior agreement, a cotenant who undertakes such an endeavor does so at his own risk and cannot seek recoupment or reimbursement if the venture proves unsuccessful.<sup>184</sup> In this same vein, there is a significant amount of case law suggesting that workovers, which do not effect an enhancement or restoration of production, are excluded from the accounting formula.<sup>185</sup>

---

176. *Cotenancy and Joint Ownership*, *supra* note at 32, at § 17; *see also, e.g., Neeley*, 732 S.W.2d at 646.

177. *Cox v. Davison*, 397 S.W.2d 200, 201 (Tex. 1965).

178. *Id.* at 201.

179. *Id.*

180. *Id.*

181. *Id.* at 203.

182. *Id.* at 201.

183. *See generally id.*

184. *Cotenancy and Joint Ownership*, *supra* note, 32, at § 20; *see, e.g., Neeley v. Intercity Mgmt. Corp.*, 732 S.W.2d 644, 646 (Tex. App.—Corpus Christi 1987, no writ).

185. *BoMar Oil & Gas, Inc. v. Loyd*, No. 10-08-00016-CV, 2009 WL 2136404, at \*2 (Tex. App.—Waco July 15, 2009), *modified*, 298 S.W.3d 832 (Tex. App.—Waco 2009, pet. denied); *Neeley*, 752 S.W.2d at 646; *Shaw & Estes v. Tex. Consol. Oil*, 299 S.W.2d 307, 315 (Tex. Civ. App.—Galveston 1957, no writ).

In *Shaw v. Estes* and *Neeley v. Intercity Management*, the courts expressly disallowed recoupment of funds expended to rework wells which then failed to produce.<sup>186</sup> In both cases, the operator sought to recoup workover and various operating expenses from multiple wells in accounting to its cotenants.<sup>187</sup> The courts made clear that only the expenses associated with producing wells could be included.<sup>188</sup> Failing to reestablish production from an already nonproducing well can be easily compared to drilling a dry hole.<sup>189</sup> However, matters become more complicated when an operator conducts multiple operations within a wellbore with varying degrees of success.<sup>190</sup> In such a scenario, the well is producing, but not all expenditures related to the well necessarily resulted in production.<sup>191</sup>

In *BoMar Oil & Gas, Inc. v. Loyd*, the operating cotenant reentered a well, attempted a workover to obtain production on a shallow Pettit zone, and then proceeded to perforate and later frac a deeper Cotton Valley zone.<sup>192</sup> The Cotton Valley zone produced; the Pettit did not.<sup>193</sup> At trial, the jury determined that the Pettit workover was not a necessary and reasonable expense.<sup>194</sup> The appellate court upheld the finding on legal and factual sufficiency grounds.<sup>195</sup> Moreover, citing *Shaw* and *Neeley* in apparent dictum, the court noted that BoMar Oil was not entitled to recoup the failed workover expenses.<sup>196</sup> This strongly suggests that, had the jury found in favor of BoMar Oil on this issue, the appeals court would have reversed.<sup>197</sup>

This line of thought, taken to its logical extreme, is cause for additional concern for cotenants pursuing drilling activities outside the scope of an operating agreement.<sup>198</sup> Multiple zones or reservoirs are often tested in a single well.<sup>199</sup> Funds expended on a reservoir or zone that does not produce would appear unrecoverable in a necessary and reasonable accounting.<sup>200</sup> Horizontal wells, which typically exploit a single reservoir, require multiple

---

186. *Neeley*, 732 S.W.2d at 647; *Shaw & Estes*, 299 S.W.2d at 315.

187. *Neeley*, 732 S.W.2d at 644; *Shaw & Estes*, 299 S.W.2d at 307.

188. *Neeley*, 732 S.W.2d at 647; *Shaw & Estes*, 299 S.W.2d at 313–14.

189. *See Dry Hole*, BLACK'S LAW DICTIONARY 536 (Bryan A. Garner ed., 8th ed. 2004) (defining dry hole as, “[a]n oil or gas well that is incapable of producing enough minerals to justify the cost of completing it and putting it into production”).

190. *See generally Cotenancy and Joint Ownership*, *supra* note 32, at § 20 (explaining the method of accounting to cotenants for the value of any minerals removed).

191. *See generally id.*

192. *BoMar Oil & Gas, Inc. v. Loyd*, No. 10-08-00016-CV, 2009 WL 2136404, at \*9–10 (Tex. App.—Waco July 15, 2009), *modified*, 298 S.W.3d 832 (Tex. App.—Waco 2009, pet. denied).

193. *Id.*

194. *Id.* at \*10.

195. *Id.*

196. *Id.* at \*9.

197. *See id.*

198. *See generally id.*

199. *See generally Well Completion 101 Part 3: Well Stimulation*, DRILLINGINFO (Oct. 30, 2014), <https://info.drillinginfo.com/well-completion-well-stimulation/>.

200. *Id.*

frac stages to complete.<sup>201</sup> Expenses related to an unsuccessful stage in a frac job may not be recoverable in an accounting.<sup>202</sup>

Exploratory wells often incur additional charges for operations not directly related to the producing formations, such as the drilling, logging, and coring of deeper unexploited reservoirs.<sup>203</sup> This line of case law strongly suggests that such expenses would also be excluded from the necessary and reasonable accounting formula.<sup>204</sup>

#### 4. Overhead

Overhead charges, such as those typically provided for in the Council of Petroleum Accountants Societies (COPAS) accounting procedures attached to most operating agreements, are a bit of a gray area.<sup>205</sup> For example, in *Prize Energy Resources v. Hoskins*, the appellate court upheld the decision to allow recoupment of COPAS overhead as a necessary and reasonable expense.<sup>206</sup>

However, in *BoMar*, the jury rejected the COPAS overhead.<sup>207</sup> The issue on appeal was whether the recoupment on the overhead was allowed as a matter of law.<sup>208</sup> At first, the appellate court agreed that overhead was a chargeable production cost, citing the “production-in-paying-quantities” doctrine.<sup>209</sup> However, the court ultimately rejected the sought recoupment on the basis that a production in paying quantities analysis requires the overhead in question to be directly attributable to either a well or its production.<sup>210</sup> As the court noted, “The record does not indicate that BoMar’s overhead fees are directly associated with production from the well.”<sup>211</sup> The court noted that Loyd’s expert testified that the fees in question were administrative expenses (such as, phone bills and secretarial pay) which BoMar would have incurred regardless of whether the well in question produced.<sup>212</sup> Because BoMar did not present evidence suggesting otherwise,

---

201. *Id.*

202. *See BoMar*, 2009 WL 2136404, at \*10.

203. *See generally Statement of Financial Accounting Standards No. 19*, FIN. ACCT. STANDARDS BOARD (Dec. 1977), [http://www.fasb.org/jsp/FASB/Document\\_C/DocumentPage?cid=1218220125741&acceptedDisclaimer=true](http://www.fasb.org/jsp/FASB/Document_C/DocumentPage?cid=1218220125741&acceptedDisclaimer=true).

204. *See BoMar*, 2009 WL 2136404, at \*10.

205. *See, e.g.*, COUNCIL OF PETROLEUM ACCOUNTANTS SOC’Y, COPAS ACCOUNTING PROCEDURES (2015), *reprinted in* JOHN S. LOWE ET AL., FORMS MANUAL TO ACCOMPANY CASES AND MATERIALS ON OIL AND GAS LAW 382 (6th ed. 2015).

206. *Prize Energy Res. v. Cliff Hoskins, Inc.*, 345 S.W.3d 537, 565–66 (Tex. App.—San Antonio 2011, no pet.)

207. *BoMar*, 2009 WL 2136404, at \*10–11.

208. *Id.* at \*4.

209. *Id.* at \*6–7.

210. *Id.* at \*8.

211. *Id.* at \*7.

212. *Id.* at \*3–4.



the appellate court upheld the rejection of the overhead costs on factual and legal sufficiency grounds.<sup>213</sup>

*B. Payout: Tract-Basis or Well-by-Well Basis?*

If more than one well is drilled on the common estate, there is an open question regarding whether payout is calculated on a well-by-well or tract-basis.<sup>214</sup> In other words, does the non-drilling cotenant begin to share in the revenue of a well upon payout of that particular well or does he begin sharing in the proceeds of all wells on the common estate only when the total revenue equals the total cost of reasonable and necessary expenses?

By way of illustration, suppose a cotenant drills two of our hypothetical Eagle Ford wells six months apart on Black Acre, a common estate with a 25% non-drilling cotenant. Under a well-by-well payout scenario, the non-drilling cotenant will begin to share in the proceeds of the Black Acre No. 1 at approximately month eleven and in Black Acre No. 2 at approximately month seventeen (each well taking about eleven months to reach payout from the start of its production, six months apart).<sup>215</sup> On a tract-basis, however, the non-drilling cotenant would only begin to share in the proceeds after approximately fourteen months.<sup>216</sup> The capital expenditure of the second well would delay an otherwise eleven-month payout of the first well.<sup>217</sup> However, the accumulated production from the first well would accelerate the payout of the second well.<sup>218</sup>

When the wells are identical, as we are assuming here—that is, they have the same well cost and same production profile—it makes virtually no difference with regard to the overall project.<sup>219</sup> However, as a practical matter, where one of the wells drilled on the common estate is a poor performer, the distinction can make a great difference.<sup>220</sup> It matters even more if one of the wells is unprofitable (though still nonetheless producing).<sup>221</sup> The only case to consider this issue directly is *Prize Energy*

---

213. *Id.*

214. *See Prize Energy Res. v. Cliff Hoskins, Inc.*, 345 S.W.3d 537, 562–65 (Tex. App.—San Antonio 2011, no pet.) (discussing whether payout is calculated on a well-by-well basis).

215. *See* Chart 3, *supra* note 72.

216. *See id.* Assuming Black Acre No. 1 and No. 2 each cost 6.5MM to create and are equally productive, the cumulative revenue of the wells will exceed 13MM at approximately fourteen months, triggering payout. *See generally id.*

217. *See id.*; U.S. Energy Info. Admin., *supra* note 67 (approximating the cost of an Eagle Ford well to be 6.5MM). Under tract-basis accounting, payout would not occur until the wells generate a cumulative revenue of 13MM, the approximate cost of the wells. *Id.*

218. *See* Chart 3, *supra* note 72. Any revenue from the first well after it has paid out 6.5MM will accelerate the payout of the second well. *Id.*

219. *See Prize*, 345 S.W.3d at 562–65 (rejecting the non-producing cotenant's well-by-well accounting approach, despite the presence of both profitable and unprofitable wells on the property).

220. *Id.*

221. *Id.*

*Resources v. Hoskins*.<sup>222</sup> In *Prize*, a total of seven wells were drilled on the common estate, three of which were unprofitable though nonetheless producing.<sup>223</sup> In *Prize*, the appellate court rejected a well-by-well accounting approach, noting the “equitable nature of a reimbursement-for-improvements claim.”<sup>224</sup> While admitting that there is no reimbursement for a dry hole, the court stated that “there was evidence that those costs [associated with the drilling of the three unprofitable wells] benefitted the estate.”<sup>225</sup> The evidence in question consisted of testimony to the effect that the unprofitable wells prevented drainage, yielded geologic information, and allowed for re-entry in the future (presumably for recompletions uphole).<sup>226</sup> The key distinction appears to be production—any production—especially in light of the fact that, with the exception of drainage protection, a dry hole would provide the same benefits to the estate as those listed by the court in *Prize*.<sup>227</sup>

The overall weight of commentary, as well as recent case law, suggests that Texas courts will favor accounting on a tract-basis.<sup>228</sup> Neither school of thought is without merit, and both have drawbacks.<sup>229</sup> However, a well-by-well accounting method would seem consistent with various industry instruments’ treatment of the concept of payout.<sup>230</sup> For example, most joint operating agreements provide that, in the event a party elects not to participate in the drilling or completion of a well, his participating partners are entitled to recoup the non-participating party’s portion of the costs (plus a penalty) from the proceeds of the well in question before the non-participator can begin to share in those proceeds.<sup>231</sup> The drilling partners cannot recoup the non-participant’s share of costs from the revenue of other wells he has participated in—even though those wells are located on the same tract and are subject to the same contract.<sup>232</sup> Moreover, many operators are, at least, accustomed to accounting in this manner.<sup>233</sup> However, a well-by-well accounting method can cause difficulties in allocating expenses

---

222. *Id.* at 537.

223. *Id.* at 562–64.

224. *Id.* at 564 (citing *Wagner & Brown, Ltd. v. Sheppard*, 198 S.W.3d 369, 428 (Tex. App.—Texarkana 2006), *rev’d on other grounds*, 282 S.W.3d 419 (Tex. 2008)).

225. *Id.* (citing *Wagner & Brown, Ltd.*, 282 S.W.3d at 429).

226. *Id.* at 564–65.

227. *Id.* at 537.

228. *See, e.g., Prize*, 345 S.W.3d at 562–63; *Mansfield*, *supra* note 174, at 20–31.

229. *See Mansfield*, *supra* note 174, at 31–32.

230. *See generally supra* text accompanying notes 74–75 (defining payout as recovery of well costs); *supra* text accompanying notes 215–16 (describing what differentiates a well-by-well from a tract-basis accounting method).

231. *See supra* FORM 610-1989 MODEL FORM OPERATING AGREEMENT, note 10, at 367.

232. *Id.*

233. *See generally, e.g., supra* Part V (explaining various common accounting scenarios associated with well costs).

for roads, processing facilities, and other improvements that are necessary for, or utilized by, several wells on the common estate.<sup>234</sup>

It would appear that, overall, a tract-basis accounting works in Big Oil's favor.<sup>235</sup> As has been noted, when the wells are identical, it makes little or no difference.<sup>236</sup> However, where some wells are generous producers and others are subeconomic, it is very much in Big Oil's interest to account on a tract-basis.<sup>237</sup> Otherwise, the expenses associated with the drilling and equipping of the subeconomic wells may never be recouped.<sup>238</sup> Moreover, when roads and tanks are constructed and installed as a necessity for the initial well, but will be used by subsequent wells drilled on the tract, allocating their expenses on a well-by-well basis would be problematic.<sup>239</sup> The entire cost of the roads and tanks could burden the first well, delaying that well's payout—perhaps indefinitely—while the nonparticipant would back in upon payout for any subsequent wells drilled on the tract which are not burdened by those expenses.<sup>240</sup>

## VI. OTHER CONSIDERATIONS

In addition to the challenges inherent in the accounting formula, additional risks or concerns quickly surface when undertaking cotenancy mineral development.

### A. *Who Owes the Royalty?*

A careful examination of the economics provided in Section IV.B above begs an important question: Who, if anyone, is responsible for paying the nonparticipant lessor's royalty? As noted above, if an undivided interest owner leased to a third party and Big Oil proceeds to drill and produce a well without that third party's participation, Big Oil's activities will not perpetuate the third-party lease beyond the primary term.<sup>241</sup> Moreover, the third-party lessee will not begin sharing in the proceeds of the well until it pays out, if at

---

234. See generally *supra* text accompanying note 10 (describing the general procedure for allocating party responsibilities and expenses).

235. See, e.g., *supra* text accompanying notes 215–18 (describing what differentiates a well-by-well basis from a tract-basis accounting method); see also *supra* text accompanying notes 228–34 (suggesting that a tract-basis is the favored accounting method).

236. See *supra* text accompanying note 219 (explaining that, when dealing with identical wells, it makes little or no difference whether payout is calculated on a tract-basis or well-by-well basis).

237. See *supra* text accompanying notes 220–21 (stating that there is a great distinction between generous producers and poor producers).

238. See *supra* text accompanying notes 220–28 (suggesting that tract-basis accounting is preferred).

239. See generally *supra* Section V.B (outlining the benefits and drawbacks of adopting a well-by-well accounting method).

240. See generally *supra* Section V.B (discussing the economics of the well-by-well accounting method).

241. *Hughes v. Cantwell*, 540 S.W.2d 742, 743 (Tex. Civ. App.—El Paso 1976, writ ref'd n.r.e.).

all.<sup>242</sup> Having discovered the presence of a producing well upon his minerals, the third-party lessor will demand to know where his royalties are.

The drilling party will insist that it has no contract with either the lessor or lessee, and therefore owes nothing—at least not until it has recouped its necessary and reasonable expenses from the proceeds of the well.<sup>243</sup> The third-party lessee, as the nonparticipating cotenant, will declare that it is receiving no proceeds from the well from which to pay royalties.<sup>244</sup> There is also an argument to be made that if Big Oil's well will not perpetuate the lease, then it obligates a royalty payment.<sup>245</sup>

There is scant case law on this topic, and there is virtually no case that has considered the matter expressly. *Earp v. Mid-Continent Petroleum Corporation*, the first case<sup>246</sup> to state that a third party's drilling will not perpetuate a lease past its primary term, stated that once a cotenant-lessee began sharing in the net proceeds of the production (upon payout), it needed to first account to its lessor for royalties due under the lease “based upon the amount of production from the beginning.”<sup>247</sup> There is no Texas case addressing this particular royalty issue,<sup>248</sup> but an examination of the issue leads one to conclude that the royalty would likely be owed, and it would be the nonparticipant lessee who would ultimately be responsible for paying it. While this may seem, at first glance, unfair to the nonparticipant lessee, this is the most logical, equitable, and likely outcome.

In determining whether a royalty is due in the first place, the issue will turn on the specific language in the lease. A typical lease will simply state that, “[t]he royalties to be paid by Lessee are as follows: On oil, one-eighth of that produced and saved from said land . . . .”<sup>249</sup> However, if the drilling and production conducted by Big Oil do not satisfy the lease's habendum clause, then perhaps they do not trigger the royalty clause either.<sup>250</sup> It may be possible to square this circle by maintaining that, while the condition of the habendum clause remains unsatisfied, the covenant for payment of royalties on production still stands.<sup>251</sup> This would result in the lease still expiring upon expiration of the primary term but the lessee nevertheless

242. *Byrom v. Pendley*, 717 S.W.2d 602, 605 (Tex. 1986).

243. *See supra* Part II (discussing recoupment of reasonable and necessary expenses in a cotenancy).

244. *See supra* Part III (explaining when proceeds are owed to a nonparticipating cotenant).

245. *See generally Hughes*, 540 S.W.2d at 744 (holding that drilling by third party did not perpetuate the lessee's lease).

246. This is the first case the Author is aware of that states this proposition.

247. *Earp v. Mid-Continent Petroleum Corp.*, 27 P.2d 855, 855 (Okla. 1933).

248. *But see* JOHN S. LOWE ET AL., CASES AND MATERIALS ON OIL AND GAS LAW 441 (West Publishing eds., 6th ed. 2013) (citing *Puckett v. First City Nat'l Bank of Midland*, 702 S.W.2d 232, 235 (Tex. App.—Eastland 1985, writ ref'd n.r.e.) (suggesting that a lessor cannot benefit from the royalty provisions of another lessor's lease).

249. *See Hughes*, 540 S.W.2d at 744; FORM 675 OIL AND GAS LEASE, *supra* note 119.

250. *See Earp*, 27 P.2d at 864.

251. *See id.*

being contractually liable for royalties on production occurring during the primary term of the lease.<sup>252</sup>

Alternately, even if one is satisfied that the express covenant to pay royalties is not enforceable because it is not the lessee's production, royalties may potentially be recoverable otherwise under "[t]he implied covenant to protect against drainage" or, more generally, an implied covenant to protect the leasehold.<sup>253</sup> Damages for breach of this implied covenant may be imposed in instances in which there is proof that there has been substantial drainage of the lessor's land and that a reasonably prudent operator would have taken measures to prevent such drainage.<sup>254</sup> Here, it would be unquestioned that the lessor had suffered drainage, for it would be undisputed that every ounce of production coming from Big Oil's well was draining the tract.<sup>255</sup> The second prong of the implied covenant, that a reasonably prudent operator would have acted to prevent the drainage, would be the point of contention.<sup>256</sup> Certainly, a prudent operator would not attempt to drill upon a tract with only a 10% ownership interest, but perhaps he would have farmed-out, participated (if such an offer was extended), or sought partition.<sup>257</sup>

Moreover, as between the lessor and lessee, the lessee is the only entity that can take actions to mitigate its damages—it can always surrender the lease.<sup>258</sup> The lessor mineral owner, having leased to the nonparticipant, no longer has possession of his mineral estate.<sup>259</sup> If his interest had remained unleased, he would have the option of leasing with Big Oil or, failing that, simply ratifying one of his cotenant's leases with Big Oil.<sup>260</sup> Otherwise, the mineral owner could simply take full advantage of his position as a mineral owner, either participating in the well if Big Oil allowed it or sharing in the revenues upon payout.<sup>261</sup> In this scenario, the mineral owner has chosen to lease in order to see his minerals developed so that he may enjoy the proceeds thereof in the form of the royalty for which he has contracted.<sup>262</sup> Having leased, he has relinquished virtually all control over his estate that he would have otherwise enjoyed as an undivided owner in the fee mineral estate.<sup>263</sup>

---

252. *See id.*

253. *Amoco Prod. Co. v. Alexander*, 622 S.W.2d 563, 568 (Tex. 1981).

254. *Id.*

255. *See, e.g., id.*

256. *See, e.g., id.*

257. *See id.*

258. *See, e.g., Superior Oil Co. v. Dabney*, 211 S.W.2d 563, 565 (Tex. 1948).

259. *See, e.g., Coastal Oil & Gas Corp. v. Garza*, 268 S.W.3d 1, 9–10 (Tex. 2008).

260. *See, e.g., Tex. & Pac. Coal & Oil Co. v. Kirtley*, 288 S.W. 619, 622 (Tex. Civ. App.—Eastland 1926, writ ref'd).

261. *See, e.g., id.*

262. *See, e.g., id.*

263. *See Glover v. Union Pac. R.R. Co.*, 187 S.W.3d 201, 214 (Tex. App.—Texarkana 2006, pet. denied) (holding that the lessee takes control of mineral interests as a fee simple determinable after the lease is executed).

Moreover, as between the driller and the nonparticipant, one would be hard-pressed to argue that the drilling party is responsible for the royalty payments of his cotenant's lessor. First, the drilling party in this scenario has no lease with the nonparticipant's lessor. He is a stranger to the nonparticipant's contract and has made no covenants, implied or otherwise. Moreover, because it is undisputed that the operator owes his non-drilling cotenant nothing until he has recouped his reasonable and necessary expenses, it would strain credulity to argue that the operator now owes him royalty merely by virtue of the fact that the cotenant has leased to a third party. "Each owner in a co-tenancy acts for himself and no one is the agent for the other nor has any authority to bind the other merely because of the relationship . . . ."<sup>264</sup> Lastly, obligating the drilling party to pay his nonparticipating cotenant's royalty burden would create an opportunity for abuse. In an aggressive cotenancy scenario, the nonparticipating cotenant and his lessor could simply amend their lease to create an inordinately large royalty.

### B. Partition by Sale

As discussed in Section IV.A, if a court determines that Black Acre is not susceptible to partition in kind because a fair and equitable division cannot be accomplished, it will resort to a partition by sale.<sup>265</sup> If there is a sale, cotenants can of course bid on the property, but in the event of a highly profitable well, the value of the property is much greater than the bonus originally paid for the leases.<sup>266</sup> The value of the property is now much higher; arguably, it is worth the present value of the recoverable reserves encompassed by the tract.

There is ample authority for the proposition that, in the event of a partition by sale, a cotenant who has made improvements on the common estate is entitled to recover the value of those improvements.<sup>267</sup> Using the economics from the Black Acre No. 1 well from Part III, the present value of the well's production is estimated at \$10.18MM.<sup>268</sup> As such, there is an argument to be made that, subject to any accounting requirements upon

---

264. *Hughes v. Cantwell*, 540 S.W.2d 742, 744 (Tex. Civ. App.—El Paso 1976, writ ref'd n.r.e.) (quoting *Myers v. Crenshaw*, 116 S.W.2d 1125, 1129 (Tex. Civ. App.—Texarkana 1938), *aff'd*, 137 S.W.2d 7 (Tex. 1940)).

265. TEX. R. CIV. P. 761, 770; *see, e.g.*, *White v. Smyth*, 214 S.W.2d 967, 973 (Tex. 1948); *supra* Section IV.A.

266. *White*, 214 S.W.2d at 973 (noting that the uncertainty of minerals throughout the property makes partition in kind less equitable).

267. *Snow v. Donelson*, 242 S.W.3d 570, 572 (Tex. App.—Waco 2007, no pet.); *Mapco, Inc. v. Carter*, 786 S.W.2d 368, 372–73 (Tex. App.—Beaumont 1989), *rev'd on other grounds*, 817 S.W.2d 686 (Tex. 1991); *Cotenancy and Joint Ownership*, *supra* note 32, at § 12.

268. *See supra* notes 82–83 and accompanying text (defining and calculating the present value of the well).

partition, Big Oil would be entitled to recoup the value of the Black Acre No. 1 well from the proceeds of the sale.<sup>269</sup>

However, if a court has ordered a sale of the estate, it likely means that the mineral estate was not susceptible to partition in kind.<sup>270</sup> In other words, there is too high a level of uncertainty as to the even distribution or quality of reservoir across the mineral estate.<sup>271</sup> Therefore, it would be difficult to maintain that another well drilled on the opposite side of Black Acre would yield similar production.<sup>272</sup> If that is the case, it is difficult to presume that the value of the improvement (that is, the well) would be allocated to the improving cotenant. The Author is not aware of a case addressing the issue of allocating the value of producing oil or gas wells in a partition (in sale or in kind) of a mineral estate.<sup>273</sup> When a court rules out a partition in kind due to the uncertain distribution of the minerals in question, it would appear inequitable to award the producing cotenant with the full value of the improvement made.

At the very least, Big Oil should be entitled to recoup its cost—its necessary and reasonable expenses from drilling the well—but here, again, the relevant authority would seem to question it.<sup>274</sup> “[A] cotenant who improves property without the consent of his cotenant cannot recover the actual amounts expended. It is well settled that the amount of the recovery for such improvements is limited to the value of the enhancement of the property at the time of the partition.”<sup>275</sup>

It would be tempting to divorce the value of the well from the value of the reserves producible from the well—the former being an improvement, the latter being a part of the estate. However, other than its salvage worth, a well has no other value apart from the reserves associated with its production. Therefore, it would seem logical (and equitable) for Big Oil to recover at least the value of its reasonable and necessary expenditures, but how much more beyond its proportionate interest in the mineral estate it could expect to be allocated from the proceeds of a sale of the mineral leasehold of Black Acre is an open question.<sup>276</sup>

---

269. See sources cited *supra* note 267 (suggesting cotenants can recover the value of improvement if partition by sale is ordered).

270. TEX. R. CIV. P. 761, 770; see also, e.g., *White*, 214 S.W.2d at 973.

271. *White*, 214 S.W.2d at 973.

272. See, e.g., *Daven Corp. v. Tarh E&P Holdings*, 441 S.W.3d 770, 779 (Tex. App.—San Antonio 2014, pet. denied).

273. *But see* *Champion v. Robinson*, 392 S.W.3d 118, 121 (Tex. App.—Texarkana 2012, pet. denied) (denying partition in kind of a 187.09 acre tract of land including oil wells). However, no mention is made of the value of the wells, the reserves, or whether there is active production. See *id.* Indeed, there seems to be significant uncertainty as to whether the owners of the mineral estate were even parties to the partition suit. See *id.*

274. *Williams v. Shamburger*, 638 S.W.2d 639, 640–41 (Tex. App.—Waco 1982, writ ref’d n.r.e.) (citing *Burton v. Williams*, 195 S.W.2d 245, 247 (Tex. Civ. App.—Waco 1946, writ ref’d n.r.e.)).

275. *Id.*

276. See generally *Williams*, 638 S.W.2d at 640.

*C. Amend Where Possible*

As discussed in Section IV.B, Big Oil can drill, top lease, and carry others in a manner that mitigates the impact to its profitability.<sup>277</sup> However, if Big Oil can successfully carry out this top-leasing strategy, it stands to reason that the competition can do the same.<sup>278</sup> Indeed, the primary reason why another operator's activity will not perpetuate a third party's lease is because courts have ruled that the intention of the lessor and lessee, as reflected in the written lease instrument, requires that the performance of the leasehold obligations are specifically assigned to the lessee.<sup>279</sup> The key takeaway here is that the language of the lease can be changed in order to avoid this result.<sup>280</sup>

A small addendum attached to the lease would change the outcome considerably, to wit:

If, at the expiration of the primary term or at any time or times thereafter, Operations, as the term is herein defined, are conducted on the leased premises to which lessee is not a party, this lease shall continue in force as though Operations were being conducted by lessee on said land. In the event production of covered minerals is obtained from a well drilled on the leased premises to which lessee is not a party (a "Third-Party Well"), Lessee covenants to pay or tender, by check or draft of Lessee, as royalty, a sum consistent with the Royalty Payment as provided in paragraph [x], equal to the amount which would be due [to] Lessor as royalty from the production of the same quantity of oil, gas or other hydrocarbon produced by Lessee (based on the quantity of production from the Third-Party Well which is reported to the regulatory agency having jurisdiction).

Or language of similar effect.

It must be noted that such an addendum or amendment would need to be executed *before* the lease in question is topped.<sup>281</sup> Regardless, prudence would demand that a company in Big Oil's position pay careful attention to the language of the leases it seeks to top. Moreover, it would behoove Big Oil to amend its own leases (at least those it feels are at risk of being topped and carried) to the effect that they provide that drilling or production operations performed by a stranger to the lease will nonetheless perpetuate Big Oil's lease.<sup>282</sup>

---

277. See *supra* Section IV.B (explaining the effects of top-leasing on the carried interest).

278. See generally *supra* Section IV.B (discussing the profitability of a top-leasing strategy).

279. *Hughes v. Cantwell*, 540 S.W.2d 742, 743-44 (Tex. Civ. App.—El Paso 1976, writ ref'd n.r.e.)

280. See *id.*

281. See, e.g., *Pierce*, *supra* note 134, at 14.

282. See *Hughes*, 540 S.W.2d at 744.



## VII. CONCLUSION

The understanding and exercise of the tactics outlined in this Article would lead to a more efficient production of hydrocarbons in the state of Texas without the necessity of the legislature resorting to the passage of a compulsive pooling statute.<sup>283</sup> The idea should be to encourage prudent risk taking and the drilling of the well for the benefit of not only the oil and gas producer but also his royalty interest owners. Few parties benefit from the stalemate that ensues when mineral cotenants cannot cooperate. The observation of the tenets highlighted in this Article should encourage the longstanding public policies of promoting oil and gas development and the protection of property rights.

---

283. See Kramer, *supra* note 2.