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FUNDAMENTALS OF OIL AND GAS ROYALTY CALCULATION

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I. INTRODUCTION

Both the amount and form of royalties that an oil and gas lessee must pay to its royalty owners will necessarily depend on the terms of the royalty clause in the lease or other instrument that creates the royalty obligation. Not surprisingly, the parties to an oil and gas instrument may occasionally disagree on the amount of royalties the lessee owes to its royalty owners under the terms of a specific royalty clause. Royalty disputes between lessors and lessees have increased in frequency in the last few years. The Texas Supreme Court has issued four opinions on royalty issues in a six-year period,[1] with a fifth opinion arriving in 2023.[2]

Perhaps, as the Texas Supreme Court has suggested, the frequency of royalty disputes is a function of the fact that oil and gas leases may "resort to industry jargon, outdated legalese, or tenuous assumptions about how judges will interpret industry jargon or outdated legalese."[3] Many of the most common terms in royalty clauses, however, are hardly unusual; indeed, many of those terms have established meanings both in the law and in their ordinary usage—terms such as "market value," "proceeds," "at the well," or "at the point of sale." Royalty litigation often arises not from the meaning of any of those terms in a vacuum but rather from how those terms may work in combination with other terms in an oil and gas lease or instrument.

An oil and gas lease is a contract between a lessor and a lessee.[4] Under a typical oil and gas lease, the lessor, as the owner of mineral rights in a tract of property, gives the lessee the right to explore for and produce oil, gas, or other minerals from the property; and in turn, the lessee agrees to pay royalties to the lessor on any oil, gas, or other minerals that the lessee

1. Nettye Engler Energy, L.P. v. BlueStone Nat. Res. II, L.L.C., 639 S.W.3d 682 (Tex. 2022); BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380 (Tex. 2020); Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, L.L.C., 573 S.W.3d 198 (Tex. 2019); Chesapeake Expl., L.L.C. v. Hyder, 483 S.W.3d 870 (Tex. 2016).

2. Devon Energy Prod. Co. v. Sheppard, No. 20-0904, 2023 WL 2438927 (Tex. March 10, 2023).

3. *Burlington Res. Oil & Gas Co.*, 573 S.W.3d at 210 n.10.

4. Exxon Corp. v. Emerald Oil & Gas Co., 348 S.W.3d 194, 210–11 (Tex. 2011) (first citing Tittizer v. Union Gas Corp., 171 S.W.3d 857, 860 (Tex. 2005); and then citing Valence Operating Co. v. Dorsett, 164 S.W.3d 656, 662 (Tex. 2005)). This Article will refer principally to oil and gas leases in describing the most common types of royalty clauses. Royalty clauses, however, are not unique to oil and gas leases. Many mineral deeds, for example, may contain provisions in which the seller reserves a royalty interest.

successfully produces from the property.[5] A "royalty," at its essence, is simply the compensation or consideration that the lessor is entitled to receive for allowing the lessee to exploit the lessor's mineral rights.[6] The "royalty clause" is the term or provision in an oil and gas lease that specifies how a lessee must calculate the lessor's royalties.[7]

As with any other kind of contract, an oil and gas lease is subject to the usual canons of contract construction.[8] The first and foremost canon of contract construction is that if a contract is unambiguous, a court must enforce it as it is written.[9] And, at least in Texas, words matter.[10] A royalty clause that entitles the lessor to "1/8 of any oil or gas production" is different from a royalty clause that entitles the lessor to "1/8 of the market value of any oil or gas production at the wellhead."[11] A royalty clause that entitles the lessor to "1/8 of the market value of any oil or gas production at the wellhead" is different from a royalty clause that entitles the lessor to "1/8 of the amount realized on the sale of any oil or gas production at the point of sale."[12]

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5. *See* David E. Pierce, *Incorporating a Century of Oil and Gas Jurisprudence Into the "Modern" Oil and Gas Lease*, 33 WASHBURN L.J. 786, 788–89 (1994) (discussing the roles of lessors and lessees and providing a representative granting clause).

6. Griffith v. Taylor, 291 S.W.2d 673, 676 (Tex. 1956); Lyle v. Jane Guinn Revocable Tr., 365 S.W.3d 341, 351 (Tex. App.—Houston [1st Dist.] 2010, pet. denied). Although this Article will refer primarily to royalty interests that derive from oil and gas leases, another common form of royalty interest is an "overriding royalty interest." An overriding royalty interest typically is "carved out of the working interest"—the lessee assigns it out of the lessee's working interest to a party other than the lessor. Sw. Energy Prod. Co. v. Berry-Helfand, 491 S.W.3d 699, 714 n.9 (Tex. 2016) (first citing MacDonald v. Follett, 180 S.W.2d 334, 336 (Tex. 1944); and then citing H.G. Sledge, Inc. v. Prospective Inv. & Trading Co., 36 S.W.3d 597, 599 n.2 (Tex. App.—Austin 2000, pet. denied)). In Texas, the same principles that govern the calculation of royalties under an oil and gas lease also largely apply to an overriding royalty interest. *See* Chesapeake Expl., L.L.C. v. Hyder, 483 S.W.3d 870, 872–73 (Tex. 2016) (comparing an overriding royalty interest to a standard royalty interest).

7. *See* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 125 (Tex. 1996) (Owen, J., concurring) (discussing royalty clauses and their various forms). Justice Owen's concurring opinion became the Texas Supreme Court's plurality opinion in *Heritage Resources*. Chesapeake Expl., L.L.C., 483 S.W.3d at 875.

8. Tittizer v. Union Gas Corp., 171 S.W.3d 857, 860 (Tex. 2005).

9. XTO Energy Inc. v. Smith Prod. Inc., 282 S.W.3d 672, 676 (Tex. App.—Houston [14th Dist.] 2009, pet. dism'd); Stewman Ranch, Inc. v. Double M Ranch, Ltd., 192 S.W.3d 808, 810 (Tex. App.—Eastland 2006, pet. denied); TSB Exco, Inc. v. E.N. Smith, III Energy Corp., 818 S.W.2d 417, 421 (Tex. App.—Texarkana 1991, no writ).

10. *See* Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, L.L.C., 573 S.W.3d 198, 200 (Tex. 2019) ("[T]he decisive factor in each case is the language chosen by the parties to express their agreement.").

11. *See infra* text accompanying notes 29–64.

12. *See infra* text accompanying notes 65–76.

As a general rule, most royalty clauses specify that the lessee must calculate its royalty payments "free of [the] expenses of production."[13] The rationale for that rule is that as between the lessor and the lessee, the lessee should bear the risk and cost inherent in drilling for oil or gas, including the risk that an oil or gas well may be a dry hole.[14] But precisely because of that risk, a lessee who drills a successful well typically receives a greater share of the production than the lessor or royalty owner who provided the mineral interest in the first place. That is why royalty interests usually range from 1/8 to 1/3—almost never more than 1/2.[15]

Nonetheless, there is no standard or uniform royalty clause.[16] As with most other states, Texas has "long recognized" a "strong public policy in favor of preserving the freedom of contract."[17] The parties to an agreement generally "have the right to contract with regard to their property as they see fit."[18] Thus, the terms of an oil and gas lease, including its royalty clause, are always negotiable.[19] The parties to an oil and gas lease may, if they wish, agree to shift some of the costs of production to the lessor or royalty

13. *Heritage Res., Inc.*, 939 S.W.2d at 121–22 (first citing Delta Drilling Co. v. Simmons, 338 S.W.2d 143, 147 (Tex. 1960)); and then citing Alamo Nat'l Bank v. Hurd, 485 S.W.2d 335, 338 (Tex. Civ. App.—San Antonio 1972, writ ref'd n.r.e.)); 8 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL & GAS LAW § 645 (Patrick H. Martin & Bruce M. Kramer eds. 9th ed. 2022); 3 EUGENE KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 42.2 (1989).

14. *See* Gary B. Conine*, Speculation, Prudent Operation, and the Economics of Oil and Gas Law*, 33 WASHBURN L.J. 670, 676 (1994) (explaining the "lessee has the risk- and cost-bearing working interest under the lease, while the lessor retains a cost-free royalty interest").

15. *See* Frank L. Cascio, Jr., *A Practical Look at the Major Differences Between Domestic and International Exploration Agreements*, 43 ROCKY MTN. MIN. L. INST. § 12.07 (1997) ("Royalties over fifty percent are rare.").

16. Bruce M. Kramer, *Interpreting the Royalty Obligation by Looking at the Express Language: What a Novel Idea*, 35 TEX. TECH L. REV. 223, 263 (2004); *see* Union Pac. Res. Group, Inc. v. Neinast, 67 S.W.3d 275, 279 (Tex. App.—Houston [1st Dist.] 2001, no pet.) ("Because each lease is individually negotiated, each varies as to the lessor's and lessee's rights and duties.").

17. Fairfield Ins. Co. v. Stephens Martin Paving, L.P., 246 S.W.3d 653, 664 (Tex. 2008).

18. *In re* Prudential Ins. Co., 148 S.W.3d 124, 129 n.11 (Tex. 2004).

19. *See* Jeff King, *Natural Gas Royalties: Lessor vs. Lessee and the Implied Covenant to Market*, 63 TEX. B.J. 854, 854 (2000) ("Oil and gas leases are negotiated contracts.") (first citing Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121 (Tex. 1996); and then citing Hitzelberger v. Samedan Oil Corp., 948 S.W.2d 497, 503 (Tex. App—Waco 1997, writ denied)); Shannon H. Ratliff & Jack Balagia, Jr., *Oil and Gas Royalty Class Action Litigation: Pushing the Limits of Rule 23 and Comparable State Class Action Rules*, 46 ROCKY MTN. MIN. L. INST. ch. 21, § 21.01[2][b] (2000) ("[O]il and gas leases are frequently and fiercely negotiated . . . .").

owner.[20] The parties may, if they wish, agree to increase or decrease the royalty interest that the lessor is entitled to receive on any oil or gas production.[21]

Just as there is no standard or uniform royalty clause, there likewise is no standard or uniform methodology for lessees to calculate their royalty payments. The amount of royalties that a lessee owes to its royalty owners will necessarily depend on the terms of the royalty clause—including not only the royalty fraction but also other language that may appear in the royalty clause.[22] Even a few small words in a royalty clause may significantly affect the way in which a lessee must calculate its royalty payments.

II. TYPES OF ROYALTY CLAUSES

Although there is no standard or uniform royalty clause, most royalty clauses tend to fall into one of three categories: (1) fixed price royalty clauses; (2) in-kind royalty clauses; or (3) monetary royalty clauses.[23] Of these three types of clauses, fixed price royalty clauses are rare—at least for oil and gas production.[24] In-kind royalty clauses are more common, and they often appear in older leases to define the royalty interest on oil production.[25] The predominant type of royalty clause, especially for gas production, is a monetary royalty clause.[26]

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20. *See* Bruce M. Kramer, *Royalty Interest in the United States: Not Cut from the Same Cloth*, 29 TULSA L.J. 449, 468 (1994) ("The parties are free in the lease or deed to expand or contract the royalty owner's freedom from costs.").

21. *See* King, *supra* note 19, at 854 ("As to the royalty amount, the parties to the lease are free to decide and define the type, basis, or standard for the royalties to be paid.") (citations omitted).

22. *See* Tara Righetti, *The Oil and Gas Lease, Part II: The Royalty Clause in an Oil and Gas Lease*, UT FUNDAMENTALS OF OIL, GAS & MINERAL LAW, Mar. 28, 2018, at 5 ("There is no standard formula for the calculation and payment of royalty. Instead, the measurement, valuation, and payment of royalty, and the costs which are borne by the royalty interest, are subject to negotiation and are determined by the language of the provisions in the oil and gas lease.").

23. *See* Byron C. Keeling & Karolyn King Gillespie, *The First Marketable Product Doctrine: Just What Is the Product*, 37 ST. MARY'S L.J. 1, 12 (2005) (describing the various forms of royalty clauses). Some early commentators identified as many as twenty different forms of royalty clauses. *See* Kramer, *supra* note 16, at 226 (citing RICHARD LEROY BENOIT, CYCLOPEDIA OF OIL AND GAS FORMS 161–82 (1926)). This Article focuses on the three most common forms.

24. Keeling & Gillespie, *supra* note 23, at 2.

25. *Id.* at 17. Although in-kind provisions appear more frequently in oil royalty clauses, they appear occasionally in gas royalty clauses too. *See* Edward B. Poitevent, II, *Post-Production Deductions from Royalty*, 44 S. TEX. L. REV. 709, 715 (2003) (describing royalties on oil and gas production).

26. *See* Poitevent, *supra* note 25, at 715 ("Royalty on gas production is generally paid in cash . . . .").

A. *Fixed Price Royalty Clauses*

A fixed price royalty clause specifies that the royalty owner is entitled to receive a fixed price on each unit of production—e.g., $3.00 per barrel of oil, 25¢ per ton of salt, etc. While rare for oil and gas production, fixed price royalty clauses are not extinct. They remain a favored type of royalty clause for minerals, like salt or sulfur, that maintain a consistent value despite changing market conditions.[27] Where they exist, fixed price royalty clauses allow the producer to calculate its royalty payments easily. If a royalty clause specifies that the royalty owner is entitled to a royalty of 25¢ per ton of salt, a producer that generates 400 tons of salt can readily determine that it must pay the royalty of $100.00.

Fixed price royalty clauses make little sense for oil or gas production. A royalty of $3.00 per barrel that may have appeared reasonable when oil prices were $16.00 a barrel in 1998 would have been much less reasonable to the royalty owner just ten years later when oil prices reached $100.00 a barrel.[28]

B. *In-Kind Royalty Clauses*

An in-kind royalty clause specifies that the royalty owner is entitled to receive a share of the production itself—e.g., 1/8 of all oil, gas, or other minerals produced and saved from the premises.[29] Unlike a fixed price or monetary royalty clause in which the royalty owner owns only a right to a potential royalty in the form of a monetary payment, a royalty owner under

27. *See* Jonathan Lotz, *Royalty Structures for the Mining "Super Cycle*,*"* 49 ROCKY MTN. MIN. L. FOUND. J. 71, 77 (2012) (noting how fixed price royalty clauses are "now generally used for quarry operations with low values and predicable operating costs"). Older leases often used fixed price royalty clauses to set royalties on casinghead gas. Kramer, *supra* note 16, at 239.

28. *See* Royal E. Peterson, *The Uranium Royalty Provision: Its Evolution, Present Complexity and Future Uncertainty,* 22 ROCKY MTN. MIN. L. INST. 21 (1976) ("With a fixed royalty, as the price of the product varies, what originated as an equitable arrangement quickly becomes distorted.").

29. *See* Keeling & Gillespie*, supra* note 23, at 17 (describing in-kind royalty clauses); *see also* Nettye Engler Energy, L.P. v. BlueStone Nat. Res. II, L.L.C., 639 S.W.3d 682, 684 (Tex. 2022) (defining an in-kind royalty clause as one in which the lessor or grantor retains a "fractional share of all minerals in place"); Rachel M. Kirk, Comment, *Variations in the Marketable-Product Rule from State to State,* 60 OKLA. L. REV. 769, 771 (2007) ("If a royalty clause states that the royalty owner is to be paid in either oil or gas, the royalty is 'in[-]kind,' and entitles the royalty owner to receive his proportionate share of the mineral produced."). *But see* Myers-Woodward, L.L.C. v. Underground Servs. Markham, L.L.C., No. 13-20-00172-CV, 2022 WL 2163857, at *5 (Tex. App.—Corpus Christi–Edinburg June 16, 2022, pet. filed) (mem. op., not designated for publication) (suggesting a clause reserving "1/8 of all . . . minerals" to the grantor was not an in-kind royalty clause). As a side-note: in the interest of disclosure, the Author, Byron Keeling, is co-counsel for Myers-Woodward.

an in-kind royalty clause owns its royalty share of the production.[30] If, for example, a royalty clause in an oil and gas lease states that the royalty owner is entitled to 1/8 of the oil production, then 1/8 of every barrel of oil that the lessee produces from the lease belongs to the royalty owner.[31]

Where the royalty owner has the necessary infrastructure to take physical possession of its royalty share of the production, a lessee may discharge its royalty obligations under an in-kind royalty clause by delivering the royalty owner's share of the production directly to the royalty owner.[32] If the royalty owner then wishes to monetize its royalty, it may make its own arrangements—on its own terms and at its own risk—to sell its share of the production to a third-party purchaser.[33]

However, at least under the terms of most in-kind royalty clauses, the fact that the royalty clause entitles the royalty owner to receive a share of the production itself does *not* mean that the lessee may force or compel the royalty owner to receive its royalty share of the production "in kind."[34] An in-kind royalty clause does not require the royalty owner to receive actual production as its royalty. Indeed, most royalty owners do not have the tanks or other facilities or infrastructure necessary to physically possess any part of the oil or gas production.[35]

If, for whatever reason, a royalty owner does not or cannot take physical possession of its royalty share of the production under an in-kind royalty clause, then the lessee or producer may discharge its royalty obligation to the royalty owner in one of several ways:

30. Hagar v. Stakes, 294 S.W. 835, 840–41 (1927); *see* KUNTZ, *supra* note 13, § 39.2(b) ("The effect of providing for delivery of royalty oil in[-]kind is to retain title to such oil in the lessor.").

31. *Nettye Engler Energy, L.P.*, 639 S.W.3d at 684; *see* James C.T. Hardwick, *Private Landowner Royalties on Oil—Theory and Reality*, SPECIAL INST. ON PRIV. OIL & GAS ROYALTIES pt. 10, § 10.5[2] (Rocky Mtn. Min. L. Found. 2003) ("It is universally held that such a clause . . . confers upon the lessor actual ownership itself of the stipulated share of oil produced."); Byron C. Keeling, *In the New Era of Oil & Gas Royalty Accounting: Drafting a Royalty Clause that Actually Says What the Parties Intend It to Mean*, 69 BAYLOR L. REV. 516, 564 n.233 (2017) ("Under 'in-kind' royalty language, the lessor effectively owns title to its royalty share of the oil production."); Pierce, *supra* note 5, § 818 ("Courts have uniformly held such leases give the lessor an ownership interest in a portion of the oil produced.").

32. 3 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 642.5 (Patrick H. Martin & Bruce M. Kramer eds., 9th ed. 2022).

33. Keeling & Gillespie, *supra* note 23, at 18 n.67.

34. Wolfe v. Prairie Oil & Gas Co., 83 F.2d 434, 437 (10th Cir. 1936); *see* Keeling, *supra* note 31, at 564 n.233 ("An 'in[-]kind' royalty provision essentially gives the lessor *the option* to receive its oil royalties in the form of the oil itself, rather than a monetary payment." (emphasis added)).

35. *See* WILLIAMS & MEYERS, *supra* note 32, § 642.5; *see also* Keeling & Gillespie*, supra* note 23, at 18 n.68 (2005) ("As a practical matter, most royalty owners lack the resources to receive delivery of oil in-kind." (internal quotation marks omitted)).

(1) The producer may deliver the royalty owner's share of the production to a pipeline purchaser or other third-party purchaser near the wellhead—free of cost, and to the royalty owner's credit—under the terms of a division order or other contract in which the purchaser pays the royalty owner directly for its share of the production.[36]
(2) The producer may buy the royalty owner's share of the production from the royalty owner on terms that the producer negotiates with the royalty owner.[37]
(3) Or, if the producer does not either buy the royalty owner's share of the production or deliver the royalty owner's share of the production to a purchaser free of cost, then under the implied marketing covenant, the producer must market and sell the royalty owner's share of the production—on the royalty owner's behalf—along with the producer's own share of the production.[38]

If, under the third of these options, the producer sells the royalty owner's share of the oil and gas production, the producer must pay the royalty owner the net proceeds that the producer received for the royalty owner's share of the production—or, in other words, the producer must pay the royalty owner its share of the actual sales price for the oil and gas production, minus the royalty owner's share of the costs that the producer incurred to make the production marketable and deliver it to the downstream point of sale.[39]

36. Keeling & Gillespie*, supra* note 23, at 18–19.

37. *Id.* at 20.

38. *Wolfe*, 83 F.2d at 437; *see* Cook v. Tompkins*,* 713 S.W.2d 417, 421 n.7 (Tex. App.—Eastland 1986, no writ) (explaining the producer has the implied authority to market the royalty owner's share of the oil or gas production "in order for the lessor to realize a recovery on his royalty interest" (citing *Wolfe*, 83 F.2d at 432)); *see also* Phillip Wm. Lear, *First Purchaser Suspense Accounts,* 33 ROCKY MTN. MIN. L. INST. § 17.02[2] (1988) ("If the lessor does not opt to take the royalty in[-]kind, either expressly or by implication, then the lessee has not only the right but the obligation to market the oil [on] the lessor's behalf."); Charles W. McDermott, *Fee Oil & Gas Lease Royalty—Variations and Problems,* 28 ROCKY MTN. MIN. L. INST. § VII (1982) ("[T]here is an implied duty for the lessee to market lessor's royalty oil where the lessor does not elect to take in[-]kind."); Jack O'Neill & Byron C. Keeling, *Valuation of Oil Royalties: From the Perspective of the Payor,* 47 INST. ON OIL & GAS L. & TAX'N § 6.02[1][b][i] (1996) ("[I]f the royalty owner is unable to receive delivery in[-]kind—or even if the royalty owner, for whatever reason, chooses not to receive delivery in[-]kind—then the lessee bears the duty of marketing the royalty oil for the royalty owner.").

39. Nettye Engler Energy, L.P. v. BlueStone Nat. Res. II, L.L.C., 639 S.W.3d 682, 696 (Tex. 2022); *Wolfe,* 83 F.2d at 430–31; Laura H. Burney, *The "Post-Production Costs" Issue in Texas and Louisiana: Implications for the Fate of Implied Covenants and Pro-Lessor Clauses in the Shale Era Oil and Gas Lease*, 48 ST. MARY'S L.J. 599, 627 n.162 (2017) ("Historically, lease forms typically provide an option for the lessor

Because any such sale arises from the implied marketing covenant, the producer must market the production in a way that mutually benefits both the producer and the royalty owner[40]—typically by selling the production for the "best price . . . reasonably available."[41] Nonetheless, the producer may properly charge the royalty owner with the royalty owner's share of any post-production costs on the theory that those post-production costs enhance the value of the production for the mutual benefit of both the producer and the royalty owner.[42]

C. *Monetary Royalty Clauses*

While an in-kind royalty clause gives the royalty owner a share of the production itself, a monetary royalty clause gives the royalty owner only the right to receive a money payment for a share of the production.[43] For example, a monetary royalty clause may provide that the lessee must pay the lessor a royalty of:

- One-eighth of the market value of the production at the wellhead; or
- 25% of the gross proceeds that the lessee receives for the production at

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to take his share of the oil royalty 'in[-]kind;' however, that option is rarely exercised . . . . Instead, the producer sells the oil and pays the lessor the fractional share of the proceeds of the sale as required in the lease."); Gary B. Conine, *Crude Oil Royalty Valuation: The Growing Controversy Over Posted Prices and Market Value*, 43 ROCKY MTN. MIN. L. INST. § 18.02[2] (1997) ("[T]he lessee, by necessity, has an implied authority to sell the royalty oil along with its own share of the production, provided it accounts to the lessor for the proceeds attributable to the royalty oil."); Keeling, *supra* note 31, at 520–21 n.17 ("If a lessor makes no arrangements to receive a royalty share of the lessee's production, then typically—but subject to the terms of the royalty clause—the lessee may market the lessor's share of the production along with the lessee's share and pay to the lessor the amount that the lessee receives for the lessor's share of the production, minus the lessor's share of any applicable post-production costs.").

40. Brian S. Tooley & Keith D. Tooley, *The Marketable Product Approach in the Natural Gas Royalty Case*, 44 ROCKY MTN. MIN. L. INST. § 21.02 (1998) ("The lessee's duty is generally to do whatever, in the circumstances, would be reasonably expected of all lessees of ordinary prudence, having due regard for the interests of both the lessor and the lessee.").

41. Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987). Generally, a producer may fulfill this duty by selling the production at a prevailing market price. *See Cook*, 713 S.W.2d at 421 (holding the "lease operator complied with the implied covenant to market the oil when he sold the production to [a buyer] at the current market price").

42. *See* Hardwick, *supra* note 31, § 10.9[1] ("If there is an expense to get the oil to market, then the royalty owner must bear that expense. If the oil requires treatment before it will be acceptable to a purchaser, then the royalty owner must bear that cost. These are but the consequences that inhere in ownership.").

43. *See* BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 387 (Tex. 2021) (describing the mechanics and calculation of a monetary royalty).

the point of sale; or

- 1/5 of the posted price for the production in the field.[44]

As these examples illustrate, monetary royalty clauses commonly include at least three components: "(i) the royalty fraction—e.g., 1/8th, 25%, 1/5th; (ii) the yardstick—e.g., market value, proceeds, price; and (iii) the location for measuring the yardstick—e.g., at the well, at the point of sale."[45]

The royalty fraction, of course, will certainly have a significant effect on the amount of royalties that a lessee owes to a royalty owner: the larger the royalty fraction or percentage, the higher the royalty. But the other two components—the yardstick, and the location for measuring the yardstick—may have an equally significant, even if less obvious, effect on the amount of a lessee's royalty payments.

1. The Yardstick

"Just as there is no standard form of royalty clause, there is no standard form of yardstick for a royalty clause."[46] Some monetary royalty clauses require that a "lessee calculate its royalty payments on the basis of the market value or market price of its oil or gas production."[47] Although the terms "market value" and "market price" are perhaps technically different,[48] most courts have treated them as synonymous in royalty cases.[49] The market value of oil and gas production is akin to its appraised value—the hypothetical value that the production would have in an open commercial market at a particular location with willing sellers and willing buyers.[50]

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44. Keeling, *supra* note 31, at 520.

45. *BlueStone*, 620 S.W.3d at 387 (quoting Keeling, *supra* note 31, at 520).

46. Keeling, *supra* note 31, at 521.

47. *See* Keeling & Gillespie*, supra* note 23, at 13–14 (citing examples).

48. *See* Kramer, *supra* note 20, at 459 ("In theory there should be a distinction between the terms market price and market value.").

49. Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically?, Part 2*, 37 NAT. RES. J. 611, 638 (1997); *see* Sartor v. United Gas Pub. Serv. Co., 84 F.2d 436, 440 (5th Cir. 1936) (using "value" and "price" interchangeably); Ark. Nat. Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935) ("As applied to this case, the term 'market price' is interchangeable with the term 'market value.'"); *see also* Bowden v. Phillips Petroleum Co., 247 S.W.3d 690, 699 (Tex. 2008) ("[A] 'market value' or 'market price' clause requires payment of royalties based on the prevailing market price for gas in the vicinity at the time of sale, irrespective of the actual sale price.").

50. *BlueStone*, 620 S.W.3d at 388; *see* Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981) ("Market value is defined as the price property would bring when it is offered for sale by one who desires, but is *not obligated to sell*, and is bought by one who is under no necessity of buying it.") (citing Polk Cnty. v. Tenneco, Inc., 554 S.W.2d 918 (Tex. 1977)).

Some royalty clauses require that a lessee calculate its royalty payments on the basis of the proceeds, sales price, or amount realized that the lessee receives for its production.[51] The terms "proceeds" and "amount realized" refer to the actual sales price that the lessee receives on selling its oil or gas production.[52] Royalty clauses containing such terms may further specify that the lessee must calculate its royalty payments on the basis of its gross or net proceeds from the sale of its production.[53] Gross proceeds are the actual gross sales price that the lessee receives for its production at the point of sale.[54] Net proceeds are the difference between the lessee's gross proceeds and the lessee's post-production costs—or the actual gross sales price for the production, minus the post-production costs that the lessee incurred to make the production marketable and deliver it to the point of sale.[55]

As a matter of simple economics, "market value" is not the same thing as "proceeds."[56] If a producer makes a good deal, then the price or proceeds it receives in a sale of its oil or gas production may be greater than the market value of the oil or gas; conversely, if a producer makes a poor deal, then the price or proceeds it receives in a sale of its oil or gas production may be less than the market value of the oil or gas.[57] The price that a producer receives

51. *See* Keeling & Gillespie, *supra* note 23, at 14–15 (listing examples).

52. *See Bowden*, 247 S.W.3d 690, 699 ("'Proceeds' or 'amount realized' clauses require measurement of the royalty based on the amount the lessee in fact receives under its sales contract for the [production]."); *see also* Tana Oil & Gas Corp. v. Cernosek, 188 S.W.3d 354, 360 (Tex. App.—Austin 2006, pet. denied) ("The term 'amount realized' has been construed by Texas courts to mean the proceeds received from the sale of the gas or oil.").

53. *BlueStone*, 620 S.W.3d at 389.

54. *See* Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996) (defining gross proceeds); Comm'r of the Gen. Land Off. v. Sandridge Energy, Inc., 454 S.W.3d 603, 612 (Tex. App.—El Paso 2014, pet. denied) (repeating the definition of gross proceeds from *Judice).*

55. *See* Ramming v. Nat. Gas Pipeline of Am., 390 F.3d 366, 372 (5th Cir. 2004) ("The phrase 'net proceeds' is by definition the sum remaining from gross proceeds of sale minus payment of expenses.") (citing Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983)).

56. Keeling & Gillespie, *supra* note 23, at 15; *see* Yzaguirre v. KCS Res., Inc., 47 S.W.3d 532, 539 (Tex. App.—Dallas 2000) ("Under a market value royalty, the lessor receives a royalty based on the current market value for the oil and gas. In contrast, a royalty based on proceeds is calculated on what the lessee actually receives for the oil and gas."), *aff'd,* 53 S.W.3d 368 (Tex. 2001).

57. *See BlueStone*, 620 S.W.3d at 388. ("Sometimes market value is more than the sales price and sometimes less."); *Bowden*, 247 S.W.3d at 699 ("The market price may or may not be reflective of the price the operator actually obtains for the gas."); Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 372 (Tex. 2001) ("Market value may be wholly unrelated to the price the lessee receives as the proceeds of a sales contract.").

in an arm's length sale may be some evidence of the market value of the production, but it is not in itself dispositive evidence of market value.[58]

Still other forms of royalty clauses, especially older oil royalty clauses, require that a lessee calculate its royalty payments on the basis of a "posted price."[59] Posted prices are prices that major oil and gas companies and other industry professionals publish for various types of oil or gas production from particular fields.[60] Flint Hills Resources, for example, publishes weekly posted prices to reflect the benchmark rates it is willing to pay for West Texas Intermediate crude oil.[61] As with the proceeds of a sale, a posted price is not necessarily the same thing as market value.[62] Posted prices may be some evidence of the market value of oil or gas production, but they are not in themselves dispositive evidence of market value.[63]

Because Texas courts must enforce the parties' intent as the parties themselves expressed it in their lease, Texas courts may not presume that the parties really meant "proceeds" when their royalty clause rests on a "market value" yardstick.[64] Thus, a few small words—the difference between "market value" and "proceeds" or "posted price"—may significantly affect the amount of royalties that a producer owes to a royalty owner.

2. The Location for Measuring the Yardstick

The location for measuring the yardstick may also affect the amount of royalties that a producer owes to a royalty owner under a monetary royalty clause.[65] Generally, oil and gas increases in value as a producer moves it from the point of production to the point of sale.[66] If crude oil that is worth

58. *Bowden*, 247 S.W.3d at 699.

59. *See* Keeling & Gillespie, *supra* note 23, at 14 n.51 (citing examples).

60. *See* Conine, *supra* note 39, § 18.01 (discussing the history and mechanics of posted prices).

61. *See* Keeling, *supra* note 31, at 568 n.244 (discussing Flint Hills Resources' posted prices).

62. *See* Koch Indus., Inc. v. Nat'l Union Fire Ins. Co., No. 89-1158-K, 1989 WL 158039, at *19 (D. Kan. Dec. 21, 1989) (noting fair market value does not necessarily equate to the posted price).

63. Diamond Shamrock Expl. Co. v. Hodel, 853 F.2d 1159, 1166 (5th Cir. 1988).

64. *See* Keeling, *supra* note 31, at 523 (contrasting how Texas and Oklahoma courts interpret leases).

65. *See* David E. Pierce, *Royalty Jurisprudence: A Tale of Two States*, 49 WASHBURN L.J. 347, 352 (2010) (explaining the change in value of oil and gas in the post-extraction process).

66. *See* David E. Pierce, *From Extraction to Enduse: The Legal Background,* SPECIAL INST. ON PRIV. OIL & GAS ROYALTIES pt. 3, at 4 (Rocky Mtn. Min. L. Found. 2003) ("As a general proposition, as oil or gas moves downstream from the wellhead it increases in value."); Matthew J. Salzman & Ashley Dillon, *Royalty Litigation Update—Where We Have Been, Where We Are, and Where We May Be Going, in*

$65 a barrel at the point of production is worth $70 a barrel at a downstream sales location, a lessor with a 1/8 royalty interest would certainly much prefer to receive 1/8 of the market value of the oil at the downstream sales location (1/8 of $70, or $8.75 a barrel) than at the point of production (1/8 of $65, or $8.125 a barrel).[67]

Some royalty clauses—perhaps even the majority—require that the lessee calculate its royalty payments on the basis of the value or price of its oil or gas production at the well or at the wellhead.[68] The terms "at the well" or "at the wellhead" refer to the point of production—the location at which the lessee extracts oil or gas production from the ground.[69] Thus, a royalty clause that specifies an "at the wellhead" location for measuring the yardstick contemplates that the royalty owner is entitled to a fractional share of the value or price of the oil or gas production in its raw natural state as it comes out of the ground—before the lessee or producer enhances the value of the production by treating it, processing it, or otherwise making it more marketable.[70]

Some royalty clauses require that the lessee calculate its royalty payments on the basis of the value or price of its oil or gas production in the field of production or at the nearest pipeline.[71] As with the term "at the wellhead," the terms "in the field of production" or "at the nearest pipeline" contemplate that the royalty owner is entitled to a fractional share of the

Kansas and Beyond, 62 ROCKY MTN. MIN. L. INST. § 18.01 (2016) ("The value of produced oil and gas generally increases as the production moves from the upstream wellhead down through the stream of commerce until it is sold to and consumed by the end user.").

67. *See* Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, L.L.C., 573 S.W.3d 198, 203 (Tex. 2019) ("It follows that a royalty on products at their downstream point of sale is more valuable than a royalty on the same products at the well."); *see also* Lynnette J. Boomgaarden, *Shooting the Rapids Without Going Over the Brink: The "Where's" and "How's" of Gas Royalty Valuation*, SPECIAL INST. ON PRIV. OIL & GAS ROYALTIES pt. 7, at [II][B] (Rocky Mtn. Min. L. Found. 2003) (recognizing how usually "[l]essors, seeking a share of any enhanced gas value as a result of post-extraction investment, want to locate the royalty valuation point as far downstream from the wellhead as possible").

68. *See* WILLIAMS & MEYERS, *supra* note 32, § 645.

69. Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983); Jeffrey C. King, *The Compression of Natural Gas: Is it Production or Post-Production? Is it Deductible from Royalties? If So, How Much?*, 1 TEX. J. OIL, GAS & ENERGY L. 36, 45 (2006).

70. Jacob C. Beach, *Valuing Royalties "At the Well" in Texas,* 16 TEX. J. OIL, GAS & ENERGY L. 1, 1 (2021); *see* King, *supra* note 69, at 45 ("The 'mouth of the well' or 'wellhead' is the location where the gas exits the earth. Consequently, by placing the point of valuation at that location, the parties have established the type of commodity for which royalties shall be paid—raw natural gas in its natural state.").

71. *See* Keeling & Gillespie, *supra* note 23, at 16 (comparing differences in language in royalty clauses).

value or price of the oil or gas production in its raw natural state—the state in which it comes out of the ground in the field of production or as it goes into the pipeline.[72] But unlike the term "at the wellhead," the terms "in the field of production" or "at the nearest pipeline" may arguably require that the lessee bear all of the costs necessary to transport the oil or gas production to a pipeline for delivery to a downstream sales market.[73]

Some royalty clauses require that the lessee calculate its royalty payments on the basis of the value or price of its oil or gas production at the point of sale or at some other specified location.[74] A royalty clause that requires that the lessee calculate its royalty payments "at the point of sale" means exactly that: under such a clause, the royalty owner is entitled to a fractional share of the value or price of the oil or gas production at the location where the lessor sells it to a third party or otherwise relinquishes title to the production—whether that location is at the wellhead or at a downstream sales location.[75]

Just as the yardstick may affect the way in which a lessee must calculate its royalty payments, so too does the location for measuring the yardstick. A few small words, such as the difference between "at the wellhead" and "at the point of sale," may have a significant effect on the way in which a lessee must calculate its royalty payments to its royalty owners.[76]

72. *See id.* (discussing the meaning of royalty clause terms); Burlington Res. Oil & Gas Co., 573 S.W.3d at 207–08 (construing "in the pipeline" royalty clause language).

73. *See* Nettye Engler Energy, L.P. v. BlueStone Nat. Res. II, L.L.C., 639 S.W.3d 682, 696 (Tex. 2022) (determining the lessee could calculate royalty payments under a workback methodology based on "in the pipe line" language in the royalty agreement); WILLIAMS & MEYERS, *supra* note 32, § 646.2 (suggesting the lessor and lessee share the costs of production under such clauses); A.W. Walker, Jr., *Nature of the Property Interests Created By an Oil and Gas Lease in Texas*, 10 TEX. L. REV. 291, 313 (1932) (noting it is not entirely clear whether the lessee or lessor should bear the cost of transporting the production to the pipeline under an "at the pipeline" royalty clause).

74. *See* Burlington Res. Oil & Gas Co., 573 S.W.3d at 204 ("Of course, the parties are free to contract for a royalty calculated based not on the value of the oil and gas at the well but on its value at the point of sale."); *see also* Scott Lansdown, *The Implied Marketing Covenant in Oil and Gas Leases: The Producer's Perspective*, 31 ST. MARY'S L.J. 297, 328 n.123 (2000) (noting "while it is customary that royalties be calculated at the well, there is nothing that would prevent the parties from agreeing to a royalty clause which provides that royalty is to be calculated at some other point").

75. Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 476 (5th Cir. 2014).

76. Keeling, *supra* note 31, at 520; *see also* Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 416 (5th Cir. 2014) ("[I]f anything is clear from the many Texas decisions dealing with royalty provisions, it is that different royalty provisions have different meanings.").

III. ROYALTY CALCULATIONS UNDER MONETARY ROYALTY CLAUSES

A lessee cannot safely assume that it may calculate its royalty payments to all of its royalty owners in exactly the same way. Even within a single field of production, a lessee may have several different forms of leases with its royalty owners—maybe some with "market value at the wellhead" royalty clauses, and maybe others with "gross proceeds" royalty clauses. The specific language in each royalty clause will determine the proper formula or methods by which a lessee may calculate its royalty payments to its royalty owners.[77]

A. *Market Value at the Wellhead*

At least in Texas, a lessor who owns a royalty interest in "1/8 of the market value of the oil and gas production at the wellhead" is not entitled to receive 1/8 of the price that the lessee receives on selling its production to a purchaser in a downstream commercial sale.[78] Under such a royalty clause, the lessor is entitled only to 1/8 of the value of the oil or gas production in its raw natural state when the lessee extracts it from the ground at the wellhead.[79] Thus, for a lessee to calculate the royalties it owes to its royalty owners under a market value at the wellhead royalty clause, the lessee must first calculate the market value of its production in its raw natural state at the wellhead.[80]

As many Texas courts have stated, the preferred way for a lessee to calculate the market value of its production at the wellhead is the comparable sales method.[81] A comparable sale is "one that is comparable

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77. Righetti, *supra* note 22, at 5.

78. *See* Exxon Corp. v. Middleton, 613 S.W.2d 240, 241–42, 246 (Tex. 1981) (detailing the difference between market value and sales proceeds or price).

79. *See* Tex. Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 871 (Tex. 1968) (holding contract price and market value are not the same). Market value royalty clauses typically provide that the valuation point is at the well or at the wellhead. There is no rule, however, that bars the parties from agreeing to move the valuation point to a different location. Although rare, some royalty clauses require the lessee to calculate its royalty payments on the basis of the market value of its production at the point of sale. *E.g., Potts*, 760 F.3d at 473.

80. *See* King, *supra* note 69, at 45 (describing royalty calculations starting with the value at the wellhead); *see also* Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996) ("[V]alue at the well means the value of the gas before . . . other value is added in preparing and transporting the gas to market.").

81. Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996); *Middleton*, 613 S.W.2d at 246.

in time, quality, quantity, and availability of marketing outlets."[82] Consequently, the comparable sales method is much like the standard methodology a real estate appraiser might use to calculate the value of real property: it permits a lessee to determine the value of its oil or gas production at the wellhead as the weighted average of prices that it and other producers have received in contemporaneous wellhead sales of the same or a similar type or quality of oil or gas production from the same field.[83]

But while the comparable sales method may be the preferred methodology, it is not the only methodology a lessee may use to calculate the market value of its production at the wellhead.[84] Indeed, as a practical matter, most lessees do not, and cannot, use the comparable sales method to calculate the wellhead value of their oil or gas production[85]—mainly because wellhead sales are uncommon; and even when they occur, the sales prices often are confidential and not otherwise publicly available.[86] Most lessees instead use the "workback" or "netback" method to calculate the value of their oil or gas production at the wellhead.[87]

82. *Heritage Res., Inc.*, 939 S.W.2d at 122.

83. *See* Hugoton Prod. Co. v. United States, 315 F.2d 868, 871 (Ct. Cl. 1963) (describing the calculation for the comparable sales method); *Middleton*, 613 S.W.2d at 246–47 ("Sales comparable in time occur under contracts executed contemporaneously with the sale of the gas in question. Sales comparable in quality are those of similar physical properties such as sweet, sour, or casinghead gas. Quality also involves the legal characteristics of the gas; that is, whether it is sold in a regulated or unregulated market, or in one particular category of a regulated market. Sales comparable in quantity are those of similar volumes to the gas in question.").

84. BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 388–89 (Tex. 2021); *see* Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 238–39 (5th Cir. 1984) ("[T]he method of proof varies with the facts of each particular case. In determining market value at the well, the point is to determine the price a reasonable buyer would have paid for the gas at the well when produced. Comparable sales of gas at other wells may be used to do this. . . . Yet another relevant measure is the one proposed by Shell, the actual sale price of the gas less costs.").

85. *See* BlueStone Nat. Res. II, L.L.C. v. Randle, 601 S.W.3d 848, 856 (Tex. App.—Fort Worth 2019) (noting "[l]essees seldom use the comparable-sales method"), *aff'd in part, rev'd in part on other grounds*, 620 S.W.3d 380 (Tex. 2021).

86. *See* King, *supra* note 19, at 856 (discussing sale locations and types of buyers); *see also* Kevin C. Abbott & Ariel E. Neiland, *Leasing and Development in the Marcellus Shale Region: Avoiding the Pitfalls,* DEVELOPMENT ISSUES IN THE MAJOR SHALE PLAYS, Paper No. 10, § I(A) (Rocky Mtn. Min. L. Found. 2010) ("Although the gas theoretically could be sold at the wellhead, in the current structure of the industry, it is more typically sold downstream."); William T. Silvia, Comment, *Slouching Toward Babel: Oklahoma's First Marketable Product Problem,* 49 TULSA L. REV. 583, 585 (2013) ("[M]ore often than not, the comparable sales method is not a viable option because there are frequently no comparable sales available to evaluate . . . .").

87. *See* Keeling, *supra* note 31, at 531 (detailing the workback method); *see also* Keith B. Hall, *Implied Covenants and the Drafting of Oil and Gas Leases*, 7 LSU J. ENERGY L. & RES. 401, 468 (2019)

Under the workback or netback method, a lessee may calculate the wellhead value of its oil or gas production as the difference between (1) the actual sales price that the lessee receives for the production at a downstream sales location and (2) all of the post-production costs that the lessee incurred to make the production marketable and deliver it to the downstream point of sale.[88] The workback method essentially assumes that a lessee may reasonably estimate the wellhead value of its production by "netting" its post-production costs from the sales proceeds it ultimately receives for its production.[89] So, if a lessee sells its crude oil production at a downstream location for $70 a barrel after incurring $20 in post-production costs, a royalty owner under a 1/8 of the market value at the wellhead royalty clause would be entitled to royalties of $6.25 a barrel (1/8 x $50 a barrel).[90]

In contrast with the production costs that a lessee incurs to produce oil or gas and extract it from the ground at the wellhead, post-production costs are the costs that a lessee incurs *after* extracting its production from the ground—including costs to collect the production, to remove impurities from the production, to move the production to a downstream market, and

("Lessees typically use a 'workback' method, estimating the value at the well as being equal to the ultimate sales price, minus any post-production costs.").

88. *See* Matthew J. Salzman & Aaron K. Friess, *Royalty Clauses: What Is Everyone Fighting About (and How Do I Avoid It)?*, DRAFTING AND NEGOTIATING THE MODERN OIL AND GAS LEASE 7–9 (Rocky Mtn. Min. L. Found. 2018) ("[T]he common practice of lessees for determining the value upon which to pay royalties is to take the value produced by the downstream sale of the production and subtract the post[-]production expenses incurred downstream of the well to get the production to the point of sale. This process is often referred to as a netback or workback method of calculating royalties.").

89. *See BlueStone*, 620 S.W.3d at 389 ("Because post[-]production costs are not incurred until after gas leaves the wellhead, and because post[-]production costs add value to the gas, backing out the necessary and reasonable costs between the sales point and the wellhead is accepted as an adequate approximation of market value at the well.") (first citing Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 125 (Tex. 1996) (Owen, J., concurring); and then citing Chesapeake Expl. L.L.C. v. Hyder, 483 S.W.3d 870, 873 (Tex. 2016)); *see also* Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, L.L.C., 573 S.W.3d 198, 207 (Tex. 2019) ("A royalty on production valued at the well does not include the value added by post-production costs. When a royalty payment is based on a downstream sales price, the value added by post-production costs must be subtracted from the sales price or otherwise accounted for in order to approximate the 'at the well' value of the products." (citation omitted) (citing *Heritage Res., Inc.*, 939 S.W.2d at 130 (Owen, J., concurring))); *Hyder,* 483 S.W.3d at 873 ("The market value at the well should equal the commercial market value less the processing and transporting expenses that must be paid before the gas reaches the commercial market."); *Heritage Res., Inc.*, 939 S.W.2d at 130 (Owen, J., concurring) ("The value of gas 'at the well' represents its value in the marketplace at any given point of sale, less the reasonable cost to get the gas to that point of sale, including compression, transportation, and processing costs.").

90. Keeling, *supra* note 31, at 532.

to get it ready for a downstream sale.[91] The post-production costs that a lessee may properly net from its downstream sales price to determine the market value of its production under a workback calculation include gathering, compression, treating, processing, transportation, and marketing costs.[92]

Over the years, some industry professionals—including some oil and gas attorneys—have loosely suggested that a "market value at the wellhead" royalty clause permits a lessee to *deduct* post-production costs from its royalty payments. Any such suggestion is at best imprecise, and it has created unnecessary confusion.[93] More correctly, a "market value at the wellhead" royalty clause permits a lessee to calculate its royalty payments on the market value of its oil or gas production in its raw natural state at the wellhead, and the workback method is one of the permissible ways in which a lessee may determine the market value of its production at the wellhead.[94] As the Texas

91. *BlueStone*, 620 S.W.3d at 389 (quoting Keeling, *supra* note 31, at 524–25).

92. Poitevent, *supra* note 25, at 714; *see Burlington Res. Oil & Gas Co.*, 573 S.W.3d at 203 ("Although parties to an agreement may define post-production costs any way they choose, the term generally applies to processing, compression, transportation, and other costs expended to prepare raw oil or gas for sale at a downstream location." (citing *Hyder*, 483 S.W.3d at 875–76)); Ramming v. Nat. Gas Pipeline Co., 390 F.3d 366, 372 (5th Cir. 2004) ("Reasonable post-production costs include transporting the gas to the market and those expenses incurred to make the gas marketable." (citing *Heritage Res., Inc.*, 939 S.W.2d at 122)); Cartwright v. Cologne Prod. Co., 182 S.W.3d 438, 444–45 (Tex. App.—Corpus Christi-Edinburg 2006, pet. denied) ("These post-production costs include taxes, treatment costs to render the gas marketable, compression costs to make it deliverable into a purchaser's pipeline, and transportation costs." (first citing Martin v. Glass, 571 F. Supp. 1406, 1410 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984); then citing *Heritage Res., Inc.*, 939 S.W.2d at 122; then citing Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.—Texarkana 1957, writ ref'd n.r.e.))).

93. *See infra* text accompanying notes 147–50 (noting that anti-deduction language is meaningless in a "market value at the wellhead" royalty clause).

94. *See* Beach, *supra* note 70, at 17 ("[T]he 'net-back' method is merely a way to reach the valuation[;] it does not constitute a deduction in the sense that it reduces the true value of the royalty."); Scott Lansdown, *The Marketable Condition Rule*, 44 S. TEX. L. REV. 667, 673 (2003) ("[T]he issue may best be framed not as whether post-production costs are deductible, but rather the point at which royalty is to be calculated."); Brian S. Wheeler, *Deducting Post-Production Costs When Calculating Royalty: What Does the Lease Provide?*, 8 APPALACHIAN J.L. 1, 29 (2008) ("[T]he 'net-back' method does not 'charge' the lessor with any expenses at all, but instead is simply a method of determining what the wellhead value of the gas would have been if there had been a market for the gas at the wellhead."); Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 475 (5th Cir. 2014) (explaining the workback method is "nothing more than a method of determining market value at the well in the absence of comparable sales data at or near the wellhead").

Supreme Court recently observed: "Strictly speaking, the workback method is not a net-proceeds calculation; rather, it is a market-value proxy."[95]

Precisely because the workback method is simply a proxy for market value, a royalty owner may challenge whether a lessee's workback calculation properly reflects the market value of the lessee's oil or gas production.[96] The market value of oil and gas at any specific location is necessarily a question of fact.[97] In royalty litigation, a royalty owner may argue and offer evidence to show that the lessee's post-production costs were excessive and unreasonable.[98] Or, if the facts permit, a royalty owner may argue and offer evidence to show that a proper comparable sales methodology yields a higher market value for the lessee's oil or gas production than the lessee's workback calculation.[99]

As a general rule, the implied marketing covenant does not apply to a "market value at the wellhead" royalty clause.[100] The price that the lessee receives in a sales transaction may be relevant to a workback calculation but only as a proxy for market value.[101] The workback method is merely one way of proving market value.[102] Accordingly, the implied marketing covenant does not typically serve any purpose under a market value royalty clause. Technically, the royalties that a lessee owes under a market value royalty clause rest on the value of the lessee's oil and gas production, and both the lessee and its royalty owners may prove the market value of the

95. *BlueStone*, 620 S.W.3d at 389 (first citing Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 135 (Tex. 1996); and then citing *Heritage Res., Inc.*, 939 S.W.2d at 130); *see* Hall, *supra* note 87, at 419–20 ("[The workback] method assumes that the value of gas at the wellhead is the price received for the gas when it is sold at market, minus the post-production (*i.e.*, post-wellhead) costs that the operator incurs between the wellhead and the place of sale. And, from a standpoint of economics, this makes sense.").

96. Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 238–39 (5th Cir. 1984) (describing the problems of proof when challenging market value).

97. *Id.* at 238; *see* Exxon Corp. v. Middleton, 613 S.W.2d 240, 248 (Tex. 1981) (noting while evidence of sales prices "may be admissible, such evidence does not bind the fact finder as a matter of law in its determination of market value").

98. *See* Owen L. Anderson, *Calculating Royalty: "Costs" Subsequent to Production—"Figures Don't Lie, But . . . ,"* 33 WASHBURN L.J. 591, 597 (1994) (stating courts should consider only "reasonable and necessary costs" in determining a lessee's royalty obligation).

99. *Piney Woods Country Life Sch.*, 726 F.2d at 239.

100. Union Pac. Res. Grp. v. Hankins, 111 S.W.3d 69, 74 (Tex. 2003); Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373–74 (Tex. 2001).

101. BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 389 (Tex. 2021) (first citing Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 135 (Tex. 1996); and then citing Heritage Res., Inc., v. NationsBank, 939 S.W.2d 118, 130 (Tex. 1996)).

102. *Id.* at 388–89.

lessee's oil and gas production through methods—such as the comparable sales method—that are "independent of the price the lessee actually obtains."[103]

B. *Net Proceeds*

In Texas, a lessor who owns a royalty interest in "1/8 of the net proceeds from the sale of the oil and gas production" is entitled to 1/8 of the difference between (1) the sales price that the lessee receives on selling its oil or gas production and (2) any post-production costs that the lessee incurred to make the production marketable and deliver it to the downstream point of sale.[104] Under such a royalty clause, a lessee who sells its production at the wellhead and incurs no post-production costs would owe the lessor 1/8 of the sales price.[105] But if the lessee sells its production at a downstream location, the lessee may use a workback methodology to calculate its royalty payments and pay the lessor 1/8 of the lessee's sales price minus the lessee's reasonable post-production costs.[106]

There is no functional difference between a royalty clause that specifies the lessor is entitled to a fractional share of the "net proceeds" and a royalty clause that specifies the lessor is entitled to a fractional share of the "net proceeds at the well."[107] By definition, a net proceeds royalty clause authorizes the lessee to "net" its post-production costs from its sales price or proceeds in calculating its royalty payments.[108] Thus, whether or not a net proceeds royalty clause contains the words "at the well," its effect is the same: it requires a lessee to calculate the effective sales price of its

103. *Yzaguirre*, 53 S.W.3d at 374; *see* James C.T. Hardwick & J. Kevin Hayes, *Gas Marketing Royalty Issues in the 1990s*, OIL AND GAS ROYALTIES ON NON-FEDERAL LANDS, Paper No. 2, § 2.05[1] (Rocky Mtn. Min. L. Inst. 1993) ("Logic suggests that the duty imposed upon a lessee to obtain the best price possible would apply only for leases containing royalty clauses under which the lessor is compensated based upon the price received by the lessee—i.e., a proceeds type clause.").

104. Ramming v. Nat. Gas Pipeline Co., 390 F.3d 366, 372 (5th Cir. 2004); Martin v. Glass, 571 F. Supp. 1406, 1411-12 (N.D. Tex. 1983); *Judice*, 939 S.W.2d at 137.

105. *See* Keeling & Gillespie*, supra* note 23, at 34 ("If the lessee sold its oil or gas production . . . at the wellhead, the lessee had to pay its lessors their proportional royalty-share of the actual price that the lessee received for its production.").

106. *Id.*; *see Judice*, 939 S.W.2d at 137 ("'Net proceeds' expressly contemplates deductions . . . ." (first citing *Martin*, 571 F. Supp. at 1411–15; and then citing *Heritage Res., Inc.*, 939 S.W.2d at 126–27)).

107. *Judice*, 939 S.W.2d at 137 (first citing *Martin*, 571 F. Supp. at 1411–15; and then citing *Heritage Res., Inc.*, 939 S.W.2d at 126–27).

108. *Id.*

production at the wellhead by deducting any post-production costs from the sales proceeds it uses to calculate its royalty payments.[109]

Because a net proceeds royalty calculation necessarily rests on the sales price that the lessee receives for its oil or gas production, the market value of the production at the wellhead is irrelevant: neither a lessee nor a lessor may rely on comparable sales at the wellhead to argue for a different royalty calculation other than the lessor's fractional share of the lessee's net proceeds.[110] At the same time, however, the implied marketing covenant commonly applies to a net proceeds royalty clause.[111] The implied marketing covenant ensures that "the lessee will not sell its production at artificially low prices to minimize [the] royalty payments" it owes to its royalty owners under a net proceeds royalty clause.[112]

C. *Gross Proceeds*

In Texas, a lessor who owns a royalty interest in "1/8 of the gross proceeds from the sale of the oil and gas production" is entitled to 1/8 of the actual sales price that the lessee receives on selling its oil or gas production.[113] The term "gross proceeds" means what it says—that the royalty owner is entitled to a royalty in the amount of the royalty owner's fractional share of the gross proceeds that the lessee ultimately receives on the sale of its oil and gas production, wherever the sales location may be.[114]

109. *See* BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 391 (Tex. 2021) ("'[A]t the well' is a net-proceeds equivalent that contemplates deductions . . . ." (citing *Judice*, 939 S.W.2d at 136)).

110. *See* Arthur J. Wright & Carla J. Sharpe, *Direct Gas Sales: Royalty Problems for the Producer*, 46 OKLA. L. REV. 235, 240 (1993) (noting the market value of the production is "generally irrelevant" under a net proceeds royalty clause).

111. Migl v. Dominion Okla. Tex. Expl. & Prod., Inc., No. 13-05-589-CV, 2007 WL 475318, at *6 (Tex. App.—Corpus Christi Feb. 15, 2007, no pet.) (mem. op.) (citing Union Pac. Res. Group Inc. v. Hankins, 111 S.W.3d 69, 70 (Tex. 2003)); *see* Stirman v. Exxon Corp., 280 F.3d 554, 562 (5th Cir. 2002) (citing Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373 (Tex. 2001)) (noting the implied covenant applies when the royalty owner is entitled to receive a share of the proceeds); Phillips Petroleum Co. v. Yarbrough, 405 S.W.3d 70, 78 (Tex. 2013) ("A duty to market is implied in leases that base royalty calculations on the price received by the lessee for the gas." (citing *Yzaguirre*, 53 S.W.3d at 373–74)); *see also* King, *supra* note 19, at 857 ("When the royalty clause directly ties the lessor's compensation to the performance of the lessee in selling the gas, the covenant to market is, and should be, implied.").

112. Keeling, *supra* note 31, at 526–27; *see* King, *supra* note 19, at 857 ("The implied covenant to market requires the lessee to 'market the production with due diligence and obtain the best price reasonably possible.'").

113. *Judice*, 939 S.W.2d at 136.

114. *See* Yzaguirre v. KCS Res., Inc., 47 S.W.3d 532, 539 (Tex. App.—Dallas 2000) (explaining that a royalty based on proceeds is dependent on the price lessee obtained for the oil and gas), *aff'd*, 53 S.W.3d 368 (Tex. 2001).

Thus, under a gross proceeds royalty clause, the lessee must pay the lessor royalties in the amount of the lessor's fractional share of the actual sales price—without charging the lessor any part of the costs that the lessee incurred to transport the production to a sales location or to make it marketable.[115]

There is no functional difference between a royalty clause that specifies the lessor is entitled to a fractional share of the "gross proceeds" and a royalty clause that specifies the lessor is entitled to a fractional share of the "gross proceeds at the point of sale."[116] A "gross proceeds" royalty clause does not require any additional language specifying a valuation point or location. Unlike a "market value" or "market price" royalty clause, a "gross proceeds" royalty clause does not depend on the market value or market price of the lessee's production at a particular location.[117] "When proceeds are valued in 'gross,' . . . the valuation point is necessarily the point of sale because that is where the gross is realized or received."[118]

Just as with net proceeds royalty clauses, the implied marketing covenant commonly applies to gross proceeds royalty clauses.[119] The implied marketing covenant ensures that the lessee will not sell its production at artificially low prices to minimize the royalty payments it owes to its royalty owners.[120]

D. *Amount Realized or Proceeds*

The proper calculation of a lessor's royalties becomes a bit more complicated when a lessor owns a royalty interest in a fractional share of the "proceeds" or "amount realized." Without the words "net" or "gross," the terms "proceeds" or "amount realized" do not—at least in and of

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115. *Judice*, 939 S.W.2d at 136; *see* BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 391 (Tex. 2021) ("[R]oyalties computed on gross amounts received means royalties are paid based on point-of-sale proceeds without deduction of post[-]production costs."); *see also* Chesapeake Expl., L.L.C. v. Hyder, 483 S.W.3d 870, 874 (Tex. 2016) ("'Gross' means '[u]ndiminished by deduction; entire.'" (quoting *Gross*, BLACK'S LAW DICTIONARY (10th ed. 2014))).

116. *BlueStone*, 620 S.W.3d at 393.

117. *Id.*; *see supra* text accompanying notes 78–103.

118. *BlueStone*, 620 S.W.3d at 391.

119. *See* Stirman v. Exxon Corp., 280 F.3d 554, 562 (5th Cir. 2002) (noting the implied covenant applies when the royalty owner is entitled to receive a share of the proceeds).

120. Keeling, *supra* note 31, at 526–27; King, *supra* note 19, at 857.

themselves—specify whether the lessee may deduct its post-production costs from the sales price that it uses to calculate its royalty payments.[121]

If a royalty clause entitles the lessor to receive a share of the "amount realized"—e.g., "1/8 of the amount realized from the sale of the oil or gas"—the general rule is that the lessee must calculate its royalty payments to the lessor on the basis of the actual sales price that the lessee received for its production at the point of sale, without any deductions for post-production costs.[122] However, the contractual context may create an exception to this general rule.[123] If other language in the royalty clause suggests that the parties intended to require the lessee to calculate its "amount realized" at the wellhead, then a lessee may properly calculate the lessor's royalty as the difference between (1) the lessor's fractional share of the sales price that the lessee received for its oil and gas production at the point of sale and (2) the lessor's fractional share of the lessee's post-production costs.[124]

The same is apparently true of a royalty clause that entitles the lessor to receive a share of the "proceeds"—e.g., "1/8 of the proceeds from the sale of the oil or gas production."[125] Although older authorities suggested that the term "proceeds," without more, was synonymous with "net proceeds"

121. *See* Joseph T. Sneed, *Value of Lessor's Share of Production Where Gas Only Is Produced*, 25 TEX. L. REV. 641, 655 (1947) ("Patently, the naked definition of the term 'proceeds' indicates nothing as to the possibility of deducting from the 'proceeds' certain expenses incurred by the lessee in making the sale.").

122. Chesapeake Expl., L.L.C. v. Hyder, 483 S.W.3d 870, 873 (Tex. 2016); Tana Oil & Gas Corp. v. Cernosek, 188 S.W.3d 354, 360 (Tex. App.—Austin 2006, pet. denied); *see BlueStone*, 620 S.W.3d at 390 (noting that usually "an 'amount realized clause,' standing alone, creates a royalty interest that is free of post[-]production costs").

123. *See* Burlington Res. Oil & Gas Co. L.P. v. Tex. Crude Energy, L.L.C., 573 S.W.3d 198, 205 (Tex. 2019) (stating "[w]e have never held that an 'amount realized' valuation method frees a royalty holder from its usual obligation to share post-production costs even when the parties have agreed to value the royalty interest at the well," and "we must examine the entire [royalty clause] in its context and in conjunction with other clauses to which the parties agreed"); *see also BlueStone*, 620 S.W.3d at 390 ("[U]nmodified 'amount realized' language does not authorize deduction of post[-]production costs, but such costs are deductible when 'amount realized' language is modified by an 'at the well' valuation point." (citing *Burlington Res. Oil & Gas Co., L.P.*, 573 S.W.3d at 211)).

124. *Burlington Res. Oil & Gas Co. L.P.*, 573 S.W.3d at 203; *see* Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 416–17 (5th Cir. 2014) (holding where the lessor was entitled to a royalty based on the "amount realized by Lessee, computed at the mouth of the well," the royalty clause was effectively a net proceeds clause under which "the physical point to be used as the basis for calculating net proceeds is the mouth of the well"); *see also* Beach, *supra* note 70, at 16 (stating *Warren* stands for the proposition that "the 'amount realized' method does not supersede the cost-bearing nature of valuation 'at the well'").

125. *Hyder*, 483 S.W.3d at 873.

rather than "gross proceeds,"[126] the Texas Supreme Court has more recently concluded that the term "proceeds" is synonymous with "amount realized" and, absent any "net" language or other contractual context suggesting that the parties intended to permit the lessee to calculate its royalty payments on the basis of its net proceeds, "is sufficient in itself to excuse the lessors from bearing post[-]production costs."[127]

Whether or not the clause contains any "net" or "gross" language, the implied marketing covenant commonly applies to a proceeds or amount realized royalty clause.[128]

E. *Gross Proceeds at the Wellhead*

Some royalty clauses, especially in older leases, may provide that the lessor owns a royalty interest in a fractional share of the "gross proceeds at the wellhead"—e.g., "1/8 of the gross proceeds that the lessee realizes for its production at the wellhead."[129] By definition, the term "gross proceeds" contemplates that the lessee must calculate its royalty payments on the basis of the price it receives for its production at the point of sale.[130] The term "at the well," however, contemplates that the lessee must calculate its royalty payments on the basis of the price or value of its production at the

126. *See* Sneed, *supra* note 121, at 655 ("It is difficult to state accurately what expenses are deductible when the term employed is either 'proceeds' alone or 'net proceeds.' It is submitted, however, that [] there should be no difference in the computation under either term."); *see also* Frederick R. Parker, Jr., Comment, *Costs Deductible by the Lessee in Accounting to Royalty Owners for Production of Oil or Gas*, 46 LA. L. REV. 895, 897 (1986) (arguing, at least at that time, that the "general current of authority" holds that the term "proceeds" is synonymous with "net proceeds").

127. *Hyder,* 483 S.W.3d at 873; *see* Jefferson D. Stewart & David F. Maron, *Post-Production Charges to Royalty Interests: What Does the Contract Say and When Is It Ignored?*, 70 MISS. L.J. 625, 634 (2000) ("'Proceeds' in a form lease royalty provision, without any adjective, has been held to mean 'gross proceeds.'"); *see also* L.B. Hailey L.P. v. Encana Oil & Gas (USA) Inc., No. 5:17-cv-00149-RCL, 2018 WL 3150691, at *3 (W.D. Tex. June 27, 2018) ("If the royalty is a 'proceeds lease' (i.e., based on the price actually received for the product), the royalty does not bear post-production costs."). The royalty clause at issue in *Hyder* was technically an "amount realized" royalty clause; however, by characterizing the royalty clause as a "proceeds" royalty clause, the court in *Hyder* effectively concluded that the terms were synonymous and indistinguishable. *Hyder*, 483 S.W.3d at 873.

128. *See* Phillips Petroleum Co. v. Yarbrough, 405 S.W.3d 70, 78 (Tex. 2013); *see also* Patrick S. Ottinger, *Calculating the Lessor's Royalty Payment: Much More than Mere Math*, 6 LSU J. ENERGY L. & RES. 1, 46 (2017) ("Under a 'Royalty Clause' in which the lessor is to be compensated on the basis of the price realized or received by the lessee, the lessee, in discharging its duty to prudently market the production, will essentially fix the price on the basis of which the lessor will be compensated by way of royalty.").

129. Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996).

130. BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 391 (Tex. 2021); *see also supra* text accompanying notes 112–14.

wellhead—i.e., the point of production.[131] The Texas Supreme Court recognized back in 1996, and reaffirmed in 2021, that the tension between the terms "gross proceeds" and "at the well" gives rise to "'an inherent conflict' that renders a royalty clause ambiguous."[132]

What the Texas Supreme Court has not addressed is exactly how a lessor and lessee should resolve a dispute over an inherently ambiguous "gross proceeds at the wellhead" royalty clause. If the lessee sells its oil or gas production at the wellhead, then the point of sale and the point of production are the same. In that event, any tension between the words "gross proceeds" and "at the wellhead" is probably irrelevant. The word "gross" may be superfluous when the lessee sells its production at the wellhead, but if the lessee incurred no post-production costs, then it has nothing to "net" from its proceeds anyway: the lessor's royalty would be the lessor's fractional share of the actual proceeds that the lessee received in its wellhead sale of the production.[133]

But if the lessee sells its oil or gas production at a downstream commercial market, then a "gross proceeds at the well" royalty clause necessarily begs the question: may the lessee use a workback methodology to calculate its royalty payments to the lessor? Industry custom and usage of trade offers little help in answering this question. Since 1996, most oil and gas professionals have avoided using the term "gross proceeds at the well" in their leases. No industry expert could credibly claim that the term "gross proceeds at the wellhead" has a recognized industry meaning in the face of Texas Supreme Court precedent holding since 1996 that the term is inherently ambiguous.

If the lessor and lessee were both involved in negotiating a "gross proceeds at the wellhead" royalty clause, they might be able to offer extrinsic evidence of their contractual intent at the time they entered into their lease.[134] Any such "gross proceeds at the wellhead" language, however, is

131. *Judice*, 939 S.W.2d at 136; *see supra* text accompanying notes 69–70.

132. *BlueStone*, 620 S.W.3d at 391; *Judice*, 939 S.W.2d at 136; *see* Dressler Fam., L.P. v. PennEnergy Res., L.L.C., 276 A.3d 729, 735, 741 (Pa. 2022) (holding "gross proceeds at the well" royalty clause was ambiguous). *But cf.* Schroeder v. Terra Energy Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App. 1997) (construing a "gross proceeds at the wellhead" royalty clause to effectively mean "net proceeds").

133. *See supra* text accompanying note 114.

134. *See* Daniel B. Kostrub & Roger S. Christenson II, *Canons of Construction for the Interpretation of Mineral Conveyances, Severances, Exceptions, and Reservations in Producing States*, 88 N.D. L. REV. 649, 654 (2012) ("[T]he court's determination that deed language is ambiguous opens the door for each party to

most likely to appear in pre-1996, older leases that the original lessee and its subsequent assignees managed to keep in place through continuous production. The current parties to older leases may not have any extrinsic evidence of the intent of the original drafters: the persons who negotiated the terms of the royalty clause may no longer be available to testify, and relevant documentary evidence may have long since disappeared.[135]

In cases where extrinsic evidence is unavailable, Texas courts occasionally proclaim, as a default rule of construction, that they must construe an ambiguous royalty clause in favor of the lessor and against the lessee.[136] But the "against the lessee" rule of lease construction may not be helpful—or even applicable—in a dispute arising from a pre-1996, older lease.[137] The "against the lessee" rule, which derives from the common law *contra proferentem* doctrine, rests on the assumption that the lessee drafted the lease.[138] The parties to an older lease may not have had any role in drafting it at all: they may have inherited the lease from predecessors in interest. The "against the lessee" rule serves little purpose when the lessee did not actually draft the lease and was not responsible for the ambiguous language.[139]

In short, "gross proceeds at the wellhead" royalty clauses may potentially raise the Gordian Knot of royalty disputes. It will be interesting to see how the parties to any disputes arising out of any such royalty clauses attempt to untangle that Gordian Knot.

introduce extrinsic evidence to 'prove' that its interpretation was the one shared by the parties at contracting.").

135. *See* Boosey & Hawkes Music Publishers, Ltd. v. Walt Disney Co., 145 F.3d 481, 488 (2d Cir. 1998) ("[M]any years after formation of the contract, it may well be impossible to consult the principals or retrieve documentary evidence to ascertain the parties' intent . . . ."); *cf.* Stewart Enters., Inc. v. RSUI Indem. Co., 614 F.3d 117, 124 (5th Cir. 2010) ("Parol evidence should only be used to determine the intentions of the parties at the time the contract was made, not after the fact.").

136. *See* Stanolind Oil & Gas Co. v. Newman Bros. Drilling Co., 305 S.W.2d 169, 176 (Tex. 1957) (Griffin, J. dissenting) (explaining when two reasonable interpretations of a royalty clause exist, the one favorable to the lessor will prevail); Zeppa v. Houston Oil Co., 113 S.W.2d 612, 615 (Tex. Civ. App.—Texarkana 1938, writ ref'd) (stating the same).

137. *See* Byron C. Keeling, *Contra Proferentem in the Oilpatch? The "Against the Lessee" Rule of Lease Construction*, 9 LSU J. OF ENERGY L. & RES. 345, 382 (2021) (noting that the "against the lessee" rule of construction should not apply "when the lessee did not draft—and was not otherwise responsible or culpable for—the ambiguous lease term").

138. *Id.* at 351; *see* Devon Energy Prod. Co. v. Sheppard, 643 S.W.3d 186, 194 n.7 (Tex. App.—Corpus Christi-Edinburg 2020) (noting the "against the lessee" rule is "based at least in part on an assumption that the lease was drafted by the lessee"), *aff'd,* No. 20-0904, 2023 WL 2438927 (Tex. March 10, 2023).

139. Keeling, *supra* note 137, at 381–82.

IV. COMPLICATING FACTORS

As if it were not hard enough to calculate royalty payments on the basis of the three common components of a monetary royalty clause,[140] other factors may further complicate royalty disputes between a lessor and lessee. Some oil and gas leases, for example, may contain "anti-deduction" clauses or "add-back" clauses that a court may need to construe in assessing whether a lessee has correctly calculated its royalty payments to its royalty owners.[141] Depending on the circumstances, a court may also need to assess the type of transaction by which the lessee sold its oil or gas production—and in particular, whether the transaction was an arm's length third party sale.[142]

A. *Anti-Deduction and Add Back Clauses*

Some oil and gas leases may contain an anti-deduction clause with language that looks much like the following:

> The lessee may not deduct from its royalty payments any of the costs and expenses related to the exploration, production, or marketing of the oil or gas production from the lease, including but not limited to any of the costs of transporting, gathering, processing, compressing, or otherwise treating the oil, gas, or other minerals.[143]

During the lease negotiation process, lessors may have bargained for such language precisely with the hope and expectation that it will allow them to share in the enhanced value of the lessee's oil and gas production at a downstream sales location.[144]

140. *See supra* text accompanying notes 44–45.
141. *See infra* text accompanying notes 143–58.
142. *See infra* text accompanying notes 163–73.
143. *E.g.,* Keeling, *supra* note 31, at 546 (reciting a similar anti-deduction clause example).
144. *See* John B. McFarland, *Negotiating the Oil and Gas Lease from the Landowner's Perspective,* ADVANCED LANDMAN'S INST. 3-6 (Rocky Mtn. Min. L. Found. 2019) ("Royalty owners have sought to prohibit producers from charging their royalties with post-production costs by including various no-deductions clauses in their leases."); *see also* Robert Theriot & Josh Downer, *Our Texas Heritage: The Summer of the No Deductions Clause*, 52-DEC HOUS. LAW. 26, [I] (2014) (noting many royalty owners attempt to contract out of a workback methodology for calculating royalty payments).

The problem is that a lease's written words are usually more important than a party's singular expectations.[145] An anti-deduction clause may not actually do what a lessor hopes or expects it to do.[146] For instance:

If the parties include an anti-deduction clause in a lease with a market value at the wellhead royalty clause, the anti-deduction clause is usually irrelevant.[147] Under a "market value at the wellhead" royalty clause, the lessee must calculate its royalty payments on the basis of the market value of its oil or gas production at the point of production.[148] When a lessee uses the workback method to determine the market value of its production at the wellhead, it is not deducting any costs from its royalty payments; rather, the lessee is using one of the permissible methodologies—which may also include the comparable sales method—to determine the market value that forms the yardstick for calculating the amount of its royalty payments.[149] "[R]egardless of how value is proven in a court of law, logic and economics tell us that there are no [post-production] costs to 'deduct' from value at the wellhead."[150]

If the parties include an anti-deduction clause in a lease with a net proceeds royalty clause, the anti-deduction clause may render the royalty clause ambiguous. A net proceeds royalty clause, by definition, contemplates that the lessee may calculate its royalty payments by "netting" or deducting the lessor's share of the lessee's post-production expenses from the lessor's share of the proceeds that the lessee received after selling its oil or gas production.[151] An anti-deduction clause, on the other hand, contemplates that the lessee may not deduct any of its post-production expenses from the proceeds that form the yardstick for calculating its royalty

145. *See supra* text accompanying notes 9–12.

146. *See* L.B. Hailey L.P. v. Encana Oil & Gas (USA) Inc., No. 5:17-cv-00149-RCL, 2018 WL 3150691, at *5 (W.D. Tex. June 27, 2018) ("It is clear from Texas case law that the text of the royalty clause itself is the key factor in determining if a no-deductions clause is effective.").

147. Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 123 (Tex. 1996); *see* Comm'r of the Gen. Land Off. v. Sandridge Energy, Inc., 454 S.W.3d 603, 611 (Tex. App.—El Paso 2014, pet. denied) (discussing *Heritage* facts and conclusions).

148. *See supra* text accompanying notes 78–80.

149. *Heritage Res., Inc.*, 939 S.W.2d at 130 (Owen, J., concurring); *see* Keeling, *supra* note 31, at 548–549 (asserting calculations are not deductions); *cf.* Yturria v. Kerr-McGee Oil & Gas Onshore, L.L.C., 291 F. App'x. 626, 632 (5th Cir. 2008) ("[W]e must determine the value of Lessors' royalty before [assessing] the impact of the leases' separate 'no deduct' provisions.").

150. *Heritage Res., Inc.*, 939 S.W.2d at 130 (Owen, J., concurring) (citing Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984).

151. *See supra* text accompanying notes 55, 104–06.

payments.[152] Just as the word "gross" is inconsistent with "at the wellhead" language,[153] the word "net" is inconsistent with an anti-deduction clause.[154]

If the parties include an anti-deduction clause in a lease with a market value at the point of sale royalty clause, and if the lessee sells its production at the wellhead, the anti-deduction clause is of no help to a lessor hoping to share in the profit of a downstream sale.[155] "Where the point of sale is in fact the wellhead, there is nothing for the lessee to 'deduct' to calculate the value or price of its production at the [point of sale]."[156] This is true even if the lessee sells its production at the wellhead to an affiliate.[157] In that instance, the lessor may certainly offer evidence, such as comparable sales, to show that the sales price is not representative of the production's market value, but the royalty valuation location will still be the point of sale—i.e., the wellhead.[158]

The same reasoning probably applies equally to another type of clause that may occasionally appear in oil and gas leases—the so-called "add-back" clause. Add-back clauses vary widely in their language, but as an example, they may contain language that looks something like the following:

> If the lessee sells its oil or gas production for a sales price that is net of any of the costs of production, treatment, transportation, marketing, or processing,

152. *See supra* text accompanying notes 143–44.

153. *See* BlueStone Nat. Res. II, L.L.C. v. Randle, 620 S.W.3d 380, 391 (Tex. 2021) ("When proceeds are valued in 'gross,' . . . the valuation point is necessarily the point of sale . . . ."); *see also supra* text accompanying notes 129–32.

154. *See* Niemeyer v. Tana Oil & Gas Corp., 39 S.W.3d 380, 386–87 (Tex. App.—Austin 2001, pet. denied); *cf.* Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 417–18 (5th Cir. 2014) (holding an anti-deductions clause did not bar a lessee from using the workback method to calculate royalties under an "amount realized," as computed at the "mouth of the well," royalty clause).

155. Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 476 (5th Cir. 2014); *see* Keeling, *supra* note 31, at 551 (noting an anti-deduction clause was just as unhelpful to the royalty owners in *Potts* as it was to the royalty owners in *Heritage*).

156. Keeling, *supra* note 31, at 551.

157. *Potts*, 760 F.3d at 476. *But see infra* text accompanying note 172 (questioning whether a lessor could argue that its lessee violates the implied marketing covenant by selling its production to an affiliate at the wellhead solely to minimize its royalty payments under a market value at the point-of-sale royalty clause).

158. *Potts*, 760 F.3d at 476 ("[H]ad Chesapeake sold the gas at a point downstream from the wellhead, then the royalty would be 1/4 of the market value of the gas at that point . . . . But Chesapeake has sold the gas at the wellhead. That is the point of sale at which market value must be calculated under the terms of the lessors' lease.").

> the lessee shall add the deduction or costs back to the sales price in calculating the amount of royalties payable to the lessor.[159]

If the parties' lease contains a market value at the wellhead royalty clause, then such an add-back clause is probably irrelevant.[160] The sales price that a lessee receives for its production is not the yardstick for calculating royalty payments under a market value royalty clause. Under a market value royalty clause, the lessee does not need to "deduct" or "add back" anything to its royalty payments; instead, it may calculate its royalty payments simply on the basis of the market value of its production at the royalty valuation location.[161]

In lieu of an anti-deduction clause or an add-back clause, a lessor who wishes to maximize its royalties may prefer to negotiate for a gross proceeds royalty clause that contains language requiring the lessee to sell its production in an arm's length sale to an unrelated and unaffiliated third-party purchaser.[162]

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159. *E.g.,* Christopher Hogan, *Review of Recent Postproduction Costs Decisions,* TEX. CLE ADVANCED OIL, GAS & ENERGY RES. LAW, Sept. 30, 2021, at III(B) (providing another example of an add-back clause).

160. *See* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 123 (Tex. 1996) (holding an anti-deductions clause is "mere surplusage" where the lessee does not actually "deduct" anything from its royalty payments, but rather uses a workback methodology to calculate the market value of its production at the wellhead).

161. *See* Shirlaine W. Props. Ltd. v. Jamestown Res., L.L.C., No. 02-18-00424-CV, 2021 WL 5367849, at *7 (Tex. App.—Fort Worth Nov. 18, 2021, pet. filed) (suggesting a necessary difference between leases that calculate value at the wellhead versus total proceeds); *see also supra* text accompanying note 50. *But cf.* Devon Energy Prod. Co. v. Sheppard, No. 20-0904, 2023 WL 2438927, at *11 (Tex. March 10, 2023) (holding, under the unique terms of the royalty clause at issue in the case, an add-back clause had the effect of requiring royalty payments in excess of the royalty owners' share of the gross proceeds).

162. *See* Keeling, *supra* note 31, at 564–65 (suggesting language that lessors may suggest to maximize their potential royalties). An anti-deduction clause is probably unnecessary in a lease with a gross proceeds or amount realized royalty clause. Chesapeake Expl., L.L.C. v. Hyder, 483 S.W.3d 870, 873 (Tex. 2016). Even so, an anti-deduction clause is not incompatible with a gross proceeds royalty clause; if nothing else, it reinforces the parties' intent that the lessor is entitled to its royalty share of the downstream sales price that the lessee receives on selling its oil and gas production. *See* Niravkumar Patel, Comment, *Enhancing Recovery and Royalties: The Flawed Decision in* French v. Occidental Permian Ltd. *and How Lessors Can Overcome Lease Language Barriers to Prohibit Post-Production Deductions*, 48 TEX. TECH L. REV. 505, 530 (2016) ("Leases with royalty valuation based on gross proceeds or amount realized are more compatible with a no deductions clause."); *see also* Beach, *supra* note 70, at 31 (arguing "[a] party seeking to avoid cost-sharing could triple-down by placing the royalty location 'off the premises' while adding the 'gross' modifier and 'no deductions' clause for good measure").

B. *Affiliate Sales*

Another factor that may complicate a lessee's calculation of its royalty payments to its royalty owners is whether the lessee sold its oil and gas production to an affiliate. For example:

Suppose that an oil and gas lease requires the lessee to pay a royalty of 1/8 of the market value of its production at the wellhead. If the lessee sells its production to an affiliate at the wellhead, the lessee may be tempted to pay its lessor 1/8 of the sales price that the lessee receives from its affiliate. The implied marketing covenant, which does not apply under a market value at the wellhead royalty clause,[163] would not bar the lessee from selling its production to an affiliate at the wellhead.[164] Even so, the lessor could still potentially challenge the lessee's royalty payments on the basis that the lessee's affiliate sales were not arm's length commercial transactions that accurately reflected the market value of the lessee's oil and gas production at the wellhead.[165]

Suppose that an oil and gas lease requires the lessee to pay a royalty of 1/8 of the price or gross proceeds it receives on the sale of its production. If the lessee sells its production to an affiliate, the lessee may be tempted to pay its lessor 1/8 of the sales price that the lessee receives from its affiliate at the point of sale.[166] The lessor could potentially challenge the lessee's royalty payments on the basis that the lessee failed to comply with the implied marketing covenant.[167] Standing alone, the mere fact that a lessee sold its production to an affiliate does not violate the implied marketing covenant.[168] However, any evidence showing that the affiliate subsequently

163. Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373–74 (Tex. 2001); *see supra* text accompanying notes 100–03.

164. *See supra* text accompanying notes 100–03.

165. *See supra* text accompanying notes 96–99; *see also* Nicolle R. Snyder Bagnell et al., *Don't Judge a Lessee By Its Relatives: Affiliate Transactions in Royalty Litigation*, 67 ROCKY MTN. MIN. L. INST. 9–37 (2021) (noting lessees must, "when possible, structure their leases, sales, and transactions in a way that enables them to successfully defend against these types of claims by showing that their affiliate prices and affiliate charges are reasonable and proper").

166. *E.g.,* Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 473 (5th Cir. 2014) (discussing facts in which the lessee calculated its royalty payments on the basis of the price it received from an affiliated company at the point of sale).

167. *See* Stirman v. Exxon Corp., 280 F.3d 554, 562 (5th Cir. 2002) (noting the implied covenant applies to proceeds royalty clauses); *see also supra* text accompanying notes 119–20.

168. *See* Judith M. Matlock, *Royalty Calculation When the Producer/Lessee Is Dealing With an Affiliated Entity*, SPECIAL INST. ON PRIV. OIL & GAS ROYALTIES § 9 (Rocky Mtn. Min. L. Found. 2003) ("Although the use of affiliates in a marketing transaction triggers closer scrutiny, it should not trigger

secured a substantial profit by reselling the production to a downstream third party purchaser may allow a jury or other fact finder to conclude that the lessee did not comply with his duty to obtain the best price reasonably available for its production.[169]

Suppose that an oil and gas lease requires the lessee to pay a royalty of 1/8 of the market value of its production at the "point of sale." If the lessee sells its production to an affiliate at the wellhead, the lessee may be tempted to pay its lessor 1/8 of the sales price that the lessee receives from its affiliate.[170] The implied marketing covenant may not protect the lessor against such a sale—on the theory that the implied covenant does not typically apply to market value royalty clauses.[171] A lessor, however, could reasonably argue that the implied marketing covenant should protect it against such a sale: if the sole purpose of the affiliate sale was to drive the point of sale back to the wellhead, then the affiliate sale does not equally benefit both the lessee and the lessor and unfairly reduces the lessor's royalty payments by using an artificial or potentially sham transaction to ensure that the lessor does not share in the increased value of the production at a downstream sales location.[172]

A lessor who wishes to maximize its royalties—and minimize the risk that affiliate sales may reduce the size of its royalty payments—may prefer to

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instant hostility to lessees. Not only are there legitimate business reasons for the creation of affiliates, there are other checks in the law which discourage abuse of the relationship between affiliates . . . . [T]he mere existence of an affiliate in a transaction should not be considered a per se breach of the express or implied covenants of a lease . . . ."); Hardwick, *supra* note 31, § 10.07[4] ("[A]s long as the market obtained is as favorable as that which a prudent operator would have obtained in an unaffiliated transaction, the lessee's duty should be discharged.").

169. *See* Hardwick, *supra* note 31, § 10.07[4] ("Problems . . . will arise where the lessee markets to an affiliate, since in that case the lessor does not enjoy the lessee's inherent self-interest protection."); Joyce Colson, *Upstream, Midstream, Downstream—The Valuation of Royalties on Federal Oil and Gas Leases*, 70 U. COLO. L. REV. 563, 569 (1999) ("The concern that develops under this scheme is whether sales to affiliates constitute sham transactions designed to minimize the price upon which royalties are paid or whether such affiliates serve legitimate marketing purposes."); *cf.* Wright & Sharpe, *supra* note 110, at 236 ("[T]he marketing affiliate can be used by the producer to conveniently 'capture costs' of marketing, therefore allowing the producer to deduct costs from the sale proceeds payable to royalty owners and other working interest owners in a specific well.").

170. *E.g., Potts*, 760 F.3d at 473 (discussing facts in which the lessee calculated its royalty payments on the basis of the price it received from an affiliated company at the point of sale).

171. *See* Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373–74 (Tex. 2001) (holding the implied marketing covenant typically does not apply where an oil and gas lease contains a market value at the wellhead royalty clause); *see also supra* text accompanying notes 100, 163–65.

172. *See* Keeling, *supra* note 31, at 550–51 n.172 (noting the lessee in *Potts* arguably breached the implied marketing covenant).

negotiate for a gross proceeds royalty clause that contains language requiring the lessee to sell its production in an arm's length sale to an unrelated and unaffiliated third-party purchaser.[173]

V. OTHER STATES

Oil and gas producers with leases in several different states should not assume that the way in which they calculate their royalty payments in Texas is the proper way in which they may calculate their royalty payments in all other producing states.[174] In particular, oil and gas producing states have diverging views on the significance of "at the wellhead" language in a royalty clause.[175] Many states agree with Texas that the term "at the wellhead" designates the location in which a lessee may calculate the price or market value of its production for royalty purposes; and those states, like Texas, permit a lessee to use a workback methodology to calculate the price or market value of its production at the wellhead.[176] Other states disagree.[177]

Some states have adopted a principle of royalty accounting known as the "first marketable product" doctrine or the "marketable condition" rule.[178] Generally, the first marketable product doctrine requires that even when a lease contains a "market value at the wellhead" or "proceeds at the wellhead" royalty clause, a lessee should calculate the price or value of its production at the location where it first obtains a marketable product.[179] Thus, in first marketable product states, a lessee may not be able to use a workback methodology to calculate its royalty payments or otherwise to

173. *Id.* at 564–65. The lessor will want to ensure that the lease specifies exactly what constitutes an affiliate sale as opposed to an arm's length sale. *Id.* at 565 n.236.

174. *Id.* at 562.

175. *See id.* at 533–34 (noting many oil and gas states interpret "at the wellhead" language in a manner similar to Texas, while other states adhere to a first marketable product rule).

176. Hurinenko v. Chevron, USA, Inc., 69 F.3d 283, 285 (8th Cir. 1995); Emery Res. Holdings, L.L.C. v. Coastal Plains Energy, Inc., 915 F. Supp. 2d 1231, 1240 (D. Utah 2012); Hemler v. Union Producing Co., 40 F. Supp. 824, 837 (W.D. La. 1941), *rev'd on other grounds*, 134 F.2d 436 (5th Cir. 1943); Cumberland Pipe Line Co. v. Commonwealth *ex rel.* Ky. St. Tax Comm'n, 15 S.W.2d 280, 284 (Ky. 1929); Atl. Richfield Co. v. State, 214 Cal. App. 3d 533, 541-42 (1989); Wall v. United Gas Pub. Serv. Co., 152 So. 561, 564 (La. 1934); Merritt v. Sw. Elec. Power Co., 499 So. 2d 210, 214 (La. Ct. App. 1986); Montana Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978); Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496, 500 (N.D. 2009).

177. *See* Keeling, *supra* note 31, at 534 (discussing the first marketable product doctrine).

178. *Id.*

179. *See* Anderson, *supra* note 49, at 642 (advocating a marketable condition rule based on the value of production at the place "where a first-marketable product has *in fact* been obtained") (emphasis in original).

deduct a proportional share of post-production costs from its royalty payments.

The first marketable product doctrine itself varies from state to state. Kansas was arguably the first state to adopt the doctrine.[180] In Kansas, a lessee must itself bear all of the post-production costs, other than transportation costs, necessary to produce a first marketable product.[181] A lessee in Kansas may not pay royalties on the basis of a workback value at the wellhead unless its production is "marketable at the well."[182] The term "marketable" does not require a commercial market at the wellhead, but it does require that the production be in a condition where the producer could sell the production if a market were to exist at the wellhead.[183]

Oklahoma is another first marketable product state. Like Kansas, Oklahoma holds that a lessee must itself bear all of the costs, other than transportation costs, necessary to produce a first marketable product.[184] In Oklahoma, a lessee may use a workback method to calculate royalty payments under a market value at the wellhead royalty clause only if the lessee can prove that (1) its post-production costs enhanced the value of an already marketable product, (2) its post-production costs were reasonable, and (3) its actual revenues (i.e., its downstream sales price) increased in proportion with the post-production costs that it desires to subtract from its revenues to calculate the wellhead value or price of its production.[185]

Colorado has adopted a more extreme version of the first marketable product doctrine. In Colorado, a lessee must itself bear all costs, *including*

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180. Schupbach v. Cont'l Oil Co., 394 P.2d 1, 5 (Kan. 1964); Gilmore v. Superior Oil Co., 388 P.2d 602, 607 (Kan. 1964).

181. Sternberger v. Marathon Oil Co., 894 P.2d 788, 796–97 (Kan. 1995); *see* Wallace B. Roderick Revocable Living Tr. v. XTO Energy, Inc., 679 F. Supp. 2d 1287, 1294 n.2 (D. Kan. 2010) ("Kansas has explicitly held that transportation costs are allocable to lessors . . . .") (citing *Sternberger*, 894 P.2d at 800); Coulter v. Anadarko Petroluem Corp., 292 P.3d 289, 306 (Kan. 2013) (stating "lessor . . . can be charged [the] proportionate share . . . of the cost to transport the gas to a market").

182. *Sternberger*, 894 P.2d at 796–97; *see* Fawcett v. Oil Producers, Inc., 352 P.3d 1032, 1034–35 (Kan. 2015) ("Broadly speaking, the rule requires operators to make gas marketable at their own expense."); *cf.* L. Ruth Fawcett Tr. v. Oil Producers Inc., 507 P.3d 1124, 1127 (Kan. 2022) (noting if the product is marketable at the wellhead in a good faith transaction, then the lessee may calculate its royalty payments on the basis of the price it actually receives at the wellhead).

183. *Sternberger*, 894 P.2d at 800.

184. Howell v. Texaco, Inc., 112 P.3d 1154, 1159–60 (Okla. 2004); Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1205 (Okla. 1998). Interestingly, the first marketable product doctrine only applies to benefit lessors, not overriding royalty interest owners. XAE Corp. v. SMR Prop. Mgmt. Co., 968 P.2d 1201, 1208 (Okla. 1998).

185. *Mittelstaedt*, 954 P.2d at 1205.

transportation costs, necessary to acquire a first marketable product.[186] A lessee in Colorado must not only place its production in a marketable condition but also transport its production to marketable location.[187] The term "at the well" does not affect royalty calculations under the first marketable product doctrine in Colorado. Indeed, courts in Colorado have stated that "at the wellhead" language in a royalty clause is "silent as to allocation of all costs, including transportation costs."[188]

West Virginia has arguably adopted still another version of the first marketable product doctrine. Like Colorado, West Virginia has ruled that a lessee must bear all of the transportation costs necessary to deliver its production to a commercial market.[189] But going even a step beyond the Colorado version of the doctrine, West Virginia has suggested that a lessee must bear all of the post-production costs up to the point of sale.[190] Courts in West Virginia have stated that "at the wellhead" language in a royalty clause is inherently ambiguous and "does not indicate *how* or *by what method* the royalty is to be calculated or the gas is to be valued."[191]

Even in first marketable product states, the parties to an oil and gas lease may contractually agree that the lessee may calculate its royalty payments on the basis of the price or value of its production in its raw natural state—so long as the parties use more explicit language than merely the words "at the wellhead" to convey their contractual intent.[192] A lessee in a first marketable product state may wish to negotiate for a royalty clause that unambiguously

186. Rogers v. Westerman Farm Co., 29 P.3d 887, 906 (Colo. 2001); *see* Garman v. Conoco, Inc., 886 P.2d 652, 659 (Colo. 1994) (noting that the implied marketing covenant requires the lessee to bear all post-production costs "necessary to place gas in a condition acceptable for market").

187. *Rogers*, 29 P.3d at 905; *see* Patterson v. BP Am. Prod. Co., 360 P.3d 211, 222 (Colo. App. 2015) (stating "[r]oyalty calculations should therefore be made at the point where a first marketable product is obtained").

188. *Rogers*, 29 P.3d at 906.

189. Est. of Tawney v. Columbia Nat. Res., L.L.C., 633 S.E.2d 22, 28 (W. Va. 2006); Wellman v. Energy Res., Inc., 557 S.E.2d 254, 265 (W. Va. 2001).

190. *Wellman*, 557 S.E.2d at 265.

191. *Est. of Tawney*, 633 S.E.2d at 28 (emphasis in original); *see* SWN Prod. Co. v. Kellam, 875 S.E.2d 216, 226–27 (W. Va. 2022) (reaffirming *Wellman* and *Tawney* are still good law in West Virginia).

192. *See Rogers*, 29 P.3d at 906 (arguing that "at the wellhead" language in itself is "silent" as to the allocation of costs); *Est. of Tawney*, 633 S.E.2d at 28 (asserting "at the wellhead" language is ambiguous); *see also* Pierce, *supra* note 65, at 374–75 ("The Colorado and West Virginia courts make it clear that it is lawful, and perfectly permissible, to allow for the deduction of costs downstream from the wellhead—one just has to use the right language.").

specifies that it may use a workback methodology in calculating its royalty payments.[193]

VI. CONCLUSION

Not all royalty clauses are alike. While only a few small words may distinguish a market value royalty clause from a gross proceeds royalty clause, the amount that a royalty owner is entitled to receive in royalties under the latter may be much different than what the royalty owner would be entitled to receive under the former. And while only a few small words may distinguish "at the wellhead" from "at the point of sale," the amount that a royalty owner is entitled to receive where the royalty valuation location is the latter may be much different than what the owner is entitled to receive where the royalty valuation location is the former.

The terms of oil and gas leases are negotiable. While form leases are available, the parties to a proposed lease may or may not agree to use a form as a model for their lease; and even if they begin with a form, they are free to modify the provisions of the form to develop a mutually agreeable lease. The scope and specific language of the royalty clause in an oil and gas lease should be something that the parties consider on the front-end during negotiations, not on the back end during litigation. The parties should take care to ensure that the royalty clause in their lease actually says what they intend it to mean.

193. Keeling, *supra* note 31, at 570.