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# Chapter 18
# ROYALTY LITIGATION UPDATE—WHERE WE HAVE BEEN, WHERE WE ARE, AND WHERE WE MAY BE GOING, IN KANSAS AND BEYOND

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## Synopsis

§ 18.01 Introduction
§ 18.02 Two Seminal Cases from the Kansas Supreme Court
[1] *Sternberger v. Marathon Oil Co.*
[2] *Fawcett v. Oil Producers, Inc. of Kansas*
§ 18.03 Private Royalty Litigation Overview and Update
[1] At the Well States
[a] Texas
[b] Louisiana
[c] Mississippi
[d] North Dakota
[e] Montana
[f] California
[g] Pennsylvania
[h] Kentucky
[2] Marketable Product States
[a] Oklahoma
[b] Arkansas
[c] New Mexico
[d] Michigan
[e] Nevada
[f] Wyoming

[3] Marketable Product and Marketable Location States
[a] Colorado
[b] West Virginia
§ 18.04 Royalties on Federal and Indian Oil and Gas Leases
[1] The Current Regulations and Unbundling of Costs
[2] Consolidated Federal Oil and Gas and Federal and Indian Coal Valuation Reform
[3] Proposed Rule Changes Concerning Royalties on Flared or Vented Gas and Setting the Royalty Percentage

## § 18.01 Introduction*

Oil and gas royalties have been a consistent source of litigation for over a century, and this litigation may well continue throughout the next century. Royalties emanate from contracts, the oil and gas leases between "lessors" and "lessees." Lessors are the entities or individuals who own the mineral estate and, therefore, have the right to use the mineral estate and reap whatever benefits they can from it (much in the same way the surface estate owners—who are often also the mineral estate owner—can beneficially use their land, like farmers who grow crops). Lessees are typically oil and gas companies, often referred to as "producers" or "production companies." By virtue of a lease, the lessor grants a "working interest" to the lessee, essentially assigning to the lessee the lessor's rights to explore for and produce hydrocarbons, such as oil and gas, from the mineral estate. Lessees are thus the "working interest owners." In exchange for granting a working interest, lessors obtain a "royalty interest" by which they are entitled to a percentage either of the hydrocarbons produced from the land ("in-kind" royalties) or of the value of the produced hydrocarbons. Lessors, therefore, are "royalty interest owners."

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. This increase in value reflects the costs and expenses required to transport and process oil and gas as it moves downstream. Because royalty percentages are almost always

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stated in numerical terms in a lease's royalty clause (e.g., one-eighth (1/8)), the actual percentage to which the lessor is entitled is typically not in dispute. Instead, the dispute is most often about where along the stream of commerce that royalty percentage should be applied or where the oil and gas should be valued for purposes of calculating the royalty. At the well or on the lease? After the production has been transported to a processing plant? After the production has been treated? After the production has been processed? At the inlet to the interstate pipelines? Somewhere else? The royalty valuation location is impactful because lessees bear all of the costs and expenses incurred before that point, but lessees and lessors proportionately share the burden of expenses incurred after that point.

This issue is often discussed in terms of "deductions." For example, a lessee might sell gas at or near the well to an affiliate midstream company that uses compressors to transport the gas through its gathering pipeline system to its processing plant, fractionates the gas stream into its multiple components (e.g., butane, propane, helium, and methane), and processes each component to meet the quality specifications of the interstate pipeline. Lessors often claim that lessees may not "deduct" the costs associated with gathering, transporting, compressing, treating, and/or processing the gas before applying their royalty percentage. In other words, royalty litigation often is an attempt by the lessors to move the location at which the royalty percentage is applied downstream from the well after certain value-enhancing costs have been incurred, thereby garnering their royalty percentage based on a higher downstream value. Conversely, lessees often claim their obligation to bear all costs under the lease ceases upstream of these deductions, and that the royalty percentage is properly applied to the lower, upstream value.

Contract interpretation is a matter of state law, and states take varying approaches to interpreting the same or substantially similar royalty clause language in the oil and gas leases. The vast majority of royalty clauses contain the phrase "at the well." Although not every royalty clause uses this phrase in the same way, several states recognize that this language identifies the location where the production should be valued and the royalty percentage applied. These states are sometimes classified as "at the well" states. Absent lease language to the contrary, in these states the lessors must bear their proportionate share of all post-production costs incurred downstream of the wellhead. Other states, however, rely on the implied covenant or duty to market and hold that, absent lease language to the contrary, the lessee has an obligation to bear all costs to produce a marketable product or production in a marketable condition. These states have become known as "marketable product rule" states. In these states, the point when oil or gas first becomes marketable is an issue that has been the crux of numerous lawsuits. Still other states have held that a lessee not only has the obligation to produce a marketable product, but also has the duty to transport that product to the market.

This chapter explores some recent developments in the area of royalty litigation, focusing first on the former leading case from Kansas and then the Kansas Supreme Court's seminal opinion from last year in *Fawcett v. Oil Producers, Inc. of Kansas*.[1] The chapter then surveys certain leading and recent decisions of private royalty interest owner litigation from other jurisdictions. Finally, it explores regulatory developments concerning royalty on production from federally owned land.

## § 18.02 Two Seminal Cases from the Kansas Supreme Court

Kansas has long been classified as a marketable product rule state. It has a rich history of royalty litigation. While Kansas trial and appellate courts have sometimes taken varying or even conflicting approaches, the Kansas Supreme Court's decisions have been fairly consistent, finding the lessees' burden to bear all costs ceases as soon as the production is marketable, which is most often at the well, but is always either before or when the production is sold.

### [1] *Sternberger v. Marathon Oil Co.*

The Kansas Supreme Court recently stated its decision in *Sternberger v. Marathon Oil Co.*[2] "is a seminal case in Kansas on the allocation between lessor and lessee of post-production expenses for natural gas wells, particularly gathering and transportation expenses."[3] In *Sternberger*, a multistate class of royalty interest owners and overriding royalty interest owners sued the defendant-lessee for deducting the expense of "constructing and maintaining [its own] gas gathering pipeline systems to transport gas from the lease to markets off the lease."[4] The supreme court recognized that "[h]istorically, about 85% of all gas purchasers paid the cost and built the lines necessary to gather and transport the gas to market."[5] Unlike the typical situation, however, "[t]here was no market for gas at the wellhead, and [the defendant-lessee] was unable to induce a gas purchaser to construct a pipeline to the well bore."[6]

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[1] 352 P.3d 1032 (Kan. 2015).

[2] 894 P.2d 788 (Kan. 1995).

[3] Coulter v. Anadarko Petroleum Corp., 292 P.3d 289, 305 (Kan. 2013).

[4] *Sternberger*, 894 P.2d at 792.

[5] *Id.*

[6] *Id.*

The parties stipulated that the rights of all royalty interest owners would be construed according to the language in the plaintiff's lease, which obligated the lessee "[t]o pay lessor for gas of whatsoever nature or kind produced and sold, or used off the premises, or used in the manufacture of any products therefrom, one-eighth (1/8), at the market price at the well . . . ."[7] Although the Kansas Supreme Court determined the royalty clause was silent as to post-production deductions, it ruled this language was unambiguous and "clearly specifie[d] that royalties [were] to be paid based on 'market price at the well.' "[8] The court announced that, "[g]enerally, Kansas law holds that transportation costs are borne proportionately by the lessor and the lessee where royalty is to be determined at the well but no market exists at the well."[9] After reviewing certain of its earlier decisions, the court examined and extensively quoted from its decision in *Matzen v. Hugoton Production Co.*,[10] including the portions of its holding expanding the deductibility of costs beyond just transportation to include "gathering, processing and marketing the gas."[11]

Next the Kansas Supreme Court considered additional prior rulings and arguments raised by amici curiae that "gathering" was distinct from "transportation."[12] While several of the earlier Kansas cases focused on transportation, that terminology appears to have been a shorthand way of describing all the post-production, post-wellhead costs at issue. Further, the *Matzen* decision expressly considered gathering and processing costs and treated them the same as transportation costs. However, the supreme court noted that its opinions in both *Gilmore v. Superior Oil Co.* and *Schupbach v. Continental Oil Co.* held that compression costs incurred away from the well were not deductible even though the royalties were to be

[7] *Id.* (alteration in original) (quoting the lease's gas royalty clause).

[8] *Id.* at 794.

[9] *Id.* at 795.

[10] 321 P.2d 576 (Kan. 1958).

[11] *Sternberger*, 894 P.2d at 797 (quoting *Matzen*, 321 P.2d at 582).

[12] *Id.* at 799.

determined at the well.[13] The court held that, under the implied covenant, "[t]he lessee has the duty to produce a marketable product, and the lessee alone bears the expense in making the product marketable."[14]

Nevertheless, the supreme court rejected the amici's argument distinguishing between gathering and transportation for the practical reason that, unlike the casinghead gas at issue in both *Gilmore* and *Schupbach*, here there was no evidence of any deduction of compression, processing, dehydration, or any other cost required to make the gas marketable.[15] Although some commentators and litigants suggest the Kansas Supreme Court recognized a distinction between transportation and other post-production expenses, the court never expressly held as much, nor did it state it was departing from its prior holding in *Matzen*. Instead, the supreme court merely recognized that two amici made that argument and that the distinction, even if valid, simply did not apply under the facts of *Sternberger*.

In *Sternberger*, consistent with all of its prior decisions save for the distinguishable casinghead gas at issue in *Gilmore* and *Schupbach*, the Kansas Supreme Court determined the gas at issue was "marketable at the well," despite not being marketed or sold there. Consequently, the defendant lessee was not required to bear all reasonable costs incurred to construct the gathering system and transport the gas to the downstream market; the plaintiff-lessors (and overriding royalty owners) had to proportionately share those costs.[16] The Kansas Supreme Court also held that the lessors were not required to bear their proportionate share of any expense required to make the gas marketable, but the court did not provide a specific definition for marketable gas.[17] As one result of *Sternberger*, several more royalty

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[13] *Id.* (citing Gilmore v. Superior Oil Co., 388 P.2d 602 (Kan. 1964); Schupbach v. Cont'l Oil Co., 394 P.2d 1 (Kan. 1964)). Further note that, unlike the typical situation when the gas stream from a gas well can be connected to and enter a first purchaser's gathering system at or near the well, the gas in both *Gilmore* and *Schupbach* was casinghead gas produced as a byproduct from oil wells, which did not have enough natural pressure for delivery to the first purchaser. *See Gilmore*, 388 P.2d at 606 ("The only purpose for the compressing station was to put enough force behind the gas to enable it to enter the pipeline *on the lease*."); *see also* Ashland Oil & Ref. Co. v. Staats, Inc., 271 F. Supp. 571, 574–75 (D. Kan. 1967) (distinguishing the casinghead gas in *Gilmore* and *Schupbach*). To date, these cases are the only instances in which the Kansas Supreme Court has found gas not to be marketable at the well; in every other case, the court has either expressly found the gas to be marketable at the well or implicitly did so by issuing a ruling resulting in the royalties being calculated based on the wellhead value.

[14] *Sternberger*, 894 P.2d at 799.

[15] *Id.* at 799–800.

[16] *Id.* at 800.

[17] *See id.*

interest owner class actions were filed asserting that various post-production costs were necessary to make gas marketable in an attempt to move the valuation point of gas further and further downstream.

### [2] *Fawcett v. Oil Producers, Inc. of Kansas*

Last year, the Kansas Supreme Court unanimously reversed the court of appeals in what is now its seminal case on this topic. In *Fawcett v. Oil Producers, Inc. of Kansas*, the plaintiff represented a class of royalty interest owners with 25 oil and gas leases entered into between 1944 and 1991.[18] The lessee-operator, defendant Oil Producers, Inc. of Kansas (OPIK), operated wells on the leases and sold "raw" natural gas to various midstream companies (the first purchasers). Pursuant to the gas purchase agreements, these third-party first purchasers took title to the gas at or near the wellhead where the gas entered their gathering systems.[19] Rather than selling the gas for a fixed price, OPIK (like most other producers in that market) sold the gas for a price that fluctuated with the commodity price under a percentage-of-index or a percentage-of-proceeds formula. "Simplified, third-party purchasers pa[id] OPIK for the raw gas received at the wellhead based on a percentage of specified index prices or the third-party purchasers' actual revenue when that gas [was] sold to others, reduced by certain costs," all of which were set forth in the gas purchase agreements between OPIK and the first purchasers.[20] After acquiring the gas, the midstream companies processed and fractionated the gas stream, separated out the natural gas liquids, converted the residue gas into "pipeline-quality" gas capable of entering the interstate pipeline, and resold the gas to a second purchaser.[21]

On summary judgment in the trial court, the royalty interest owner class argued that "the 'sale' for royalty purposes occurred when the third-party purchasers resold the processed natural gas and its liquid byproducts, not when OPIK sold the raw gas at the wellhead."[22] In short, the class argued the gas was not marketable until it was delivered into interstate pipelines, and no expenses incurred before that point could be deducted from the value to which their royalty percentage should be applied. The trial court granted partial summary judgment to the royalty interest owner class, and the court of appeals affirmed. Central to the appellate panel's decision was the conclusion that the downstream index price or the third-party

[18] 352 P.3d 1032, 1034 (Kan. 2015).

[19] *Id.* at 1035–36.

[20] *Id.* at 1036.

[21] *See id.* at 1035.

[22] *Id.* at 1037.

purchasers' actual revenue when the gas was resold to the second purchasers—not the actual (necessarily lower) price the first purchasers paid to OPIK for the gas at the wellhead—was the "gross sales price" or "gross proceeds" for the gas OPIK sold to the first purchasers.[23]

The Kansas Supreme Court's analysis began with the terms of the lease.[24] After noting that the court's prior opinions had already interpreted and found unambiguous the royalty clause language at issue,[25] the court examined the gas purchase contracts between OPIK and the first purchasers and rejected the premise underpinning the lower court's decision that the gross sales price was the downstream index or resale value. Instead, the court found "the third-party purchase contract pricing formulas in this case more clearly represent[ed] a negotiated sale price for the gas, *i.e.*, the total sum paid in exchange for the gas delivered at the wellhead."[26] The court recognized the contract sales price was the price paid by the first purchasers to OPIK for delivery of gas at the wellhead, not the higher downstream value of the gas.

Regardless of the gas purchase contract language, however, the royalty interest owner class argued "OPIK [was] required to bear the entire expense of transforming raw natural gas [produced at the wellhead] into the quality required for transmission into the interstate pipeline system" because "raw natural gas sold at the well is not marketable as a matter of law or fact until it is processed and enters an interstate pipeline . . . ."[27] The supreme court disagreed and refused to equate marketable condition with interstate pipeline quality.[28] While the court reaffirmed the marketable

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[23] *Id.* at 1036–38; *see* Fawcett v. Oil Producers, Inc. of Kan., 306 P.3d 318 (Kan. Ct. App. 2013). As the appellate court found: "Apparently, OPIK calculated the royalty it owed to the royalty owners based on the gross proceeds of gas sales at the well to gas purchasers less the cost of the stipulated price adjustments contained in the gas purchase contracts between OPIK and the gas purchasers." *Id.* at 320. The appellate court also noted:

> Next, we must consider whether OPIK can avoid its obligations under the implied duty to market the gas by negotiating and contracting with a gas purchaser for a gross sale price of the gas sold at the well and then allow the gas purchaser to deduct from that gross sale price any amount used to compress, dehydrate, treat, and gather the gas.

*Id.* at 325.

[24] *See Fawcett*, 352 P.3d at 1039.

[25] *Id.* (citing Waechter v. Amoco Prod. Co., 537 P.2d 228 (Kan. 1975); Matzen v. Cities Serv. Oil Co., 667 P.2d 337 (Kan. 1983); Lightcap v. Mobil Oil Corp., 562 P.2d 1 (Kan. 1977)).

[26] *Id.*

[27] *Id.*

[28] *Id.*

condition approach, it reviewed *Gilmore*, *Schupbach*, and *Sternberger* and drew a stark distinction between non-deductible production expenses, such as drilling and equipping a well, and deductible post-production expenses, such as fractionating and processing the gas to meet interstate pipeline specifications:

> We believe these cases taken together demonstrate that when gas is sold at the well it has been marketed; and when the operator is required to pay royalty on its proceeds from such sales, the operator may not deduct any pre-sale expenses required to make the gas acceptable to the third-party purchaser. But post-sale, post-production expenses to fractionate raw natural gas into its various valuable components or transform it into interstate pipeline quality gas are different than expenses of drilling and equipping the well or delivering the gas to the purchaser.[29]

The Kansas Supreme Court also drew a stark distinction between Kansas law and the Colorado precedent in *Rogers v. Westerman Farm Co.*[30] The court recognized that in Colorado "an operator can be solely responsible for post-production, post-[wellhead-]sale processing expenses when the lease requires royalties to be calculated on the operator's proceeds from the sale of gas at the well."[31] To reach that result, "the *Rogers* court determined the 'at the well' language did not establish the geographical point of valuation for calculating royalty payments and the leases were therefore silent with respect to the allocation of post-production transportation and processing expenses."[32] The Kansas Supreme Court found this reasoning directly "at odds with our Kansas caselaw . . . giving effect to the 'at the well' language" concerning royalties due on gas sold at the well under a proceeds lease, and expressly declined to follow the Colorado precedent.[33]

Instead, the court determined that, in Kansas, the lessee's obligation to bear the costs of producing a marketable product is satisfied once gas is in a condition acceptable to a first purchaser, which can be (and in this case was) at the wellhead:

> We hold that when a lease provides for royalties based on a share of proceeds from the sale of gas at the well, and the gas is sold at the well, the operator's duty to bear the expense of making the gas marketable does not, as a matter of law, extend beyond that geographical point to post-sale expenses. In other words, the duty to make gas marketable is satisfied when the operator delivers the gas to the

[29] *Id.* at 1041–42 (citations omitted).

[30] 29 P.3d 887 (Colo. 2001); *see* Owen L. Anderson, "Rogers, Wellman, and the New Implied Marketplace Covenant," *Private Oil and Gas Royalties* 13A-1 (Rocky Mt. Min. L. Fdn. 2003).

[31] *Fawcett*, 352 P.3d at 1042.

[32] *Id.*

[33] *Id.*

> purchaser in a condition acceptable to the purchaser in a good faith transaction. OPIK satisfied its duty to market the gas when the gas was sold at the wellhead.[34]

Subject to language in the lease, once gas is in a condition acceptable to a first purchaser in a good-faith transaction, all further costs incurred are to be shared proportionately by lessors. As the Kansas Supreme Court held, "these leases do not impose on the operator as a matter of law the responsibility to perform the post-production, post-sale gathering, compressing, dehydrating, treating, or processing that may be necessary to convert the gas sold at the wellhead into gas capable of transmission into interstate pipelines."[35]

*Fawcett* appears to be the death knell for several previously common royalty interest owner claims. Most important among them was the claim that gas is per se not marketable at the wellhead and does not become marketable until it is "commercially fungible" or "pipeline quality," meaning it satisfies interstate pipeline specifications. Even if this were a legally credible argument before *Fawcett*, it is not now. Relatedly, several Kansas royalty interest owner classes contended that wellhead gas sales contracts were not true purchase and sale agreements; rather, the contracts were really gas service agreements under which lessees paid vendors to provide a service and, in essence, to perform the lessees' obligations (much like a contract to have a vendor supply a rig to drill the well).[36] *Fawcett* rejected that argument. Several Kansas royalty interest owner classes also previously argued that royalties must be paid separately on each constituent within the gas stream (e.g., methane, butane, propane, helium) instead of being paid on a single value for the entire gas stream produced from the well.[37] Again, *Fawcett* directly contradicts that position.

The *Fawcett* decision has impacted multiple pending royalty interest owner class actions in Kansas, some of which have since been voluntarily dismissed.[38] The opinion likely will be utilized in other marketable product rule jurisdictions, particularly by producers with third-party wellhead gas

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[34] *Id.* (citation omitted) (citing Waechter v. Amoco Prod. Co., 537 P.2d 228 (Kan. 1975)).

[35] *Id.* at 1035.

[36] *See, e.g.*, Complaint-Class Action, Spieker v. Quest Cherokee, LLC, No. 6:07-cv-01225 (D. Kan. dismissed Apr. 12, 2012), 2007 WL 4664579; Class Action Petition, Jerry D. Friess Living Trust v. Layne Energy Operating LLC, No. 2011CV57 (Kan. Dist. Ct. Oct. 24, 2011).

[37] *See, e.g.*, Dart Cherokee Basin Operating Co. v. Owens, 135 S. Ct. 547 (2014); First Amended Class Action Complaint, Owens v. Dart Cherokee Basin Operating Co., No. 5:12-cv-04157 (D. Kan. Dec. 29, 2015), ECF No. 71; Class Action Petition, Wallace B. Roderick Revocable Living Trust v. Kan. Natural Gas, Inc., No. 09CV14 (Kan. Dist. Ct. June 8, 2009).

[38] *See, e.g.*, Simon v. Horseshoe Operating, Inc., No. 6:15-cv-01162 (D. Kan. dismissed Mar. 23, 2016).

sales contracts. Yet *Fawcett* did not definitively answer or dispose of all royalty interest owner issues. For example, the opinion states that "[w]hat it means to be 'marketable' remains an open question."[39] Taken out of context, this sentence could suggest that there has been no further development in the Kansas story since *Sternberger*. However, although the supreme court does not purport to provide a scientific definition of the composition of a gas stream that qualifies it as being marketable, when viewed in context the opinion does clarify that gas is marketable when it is in a form acceptable to a first purchaser.

## § 18.03 Private Royalty Litigation Overview and Update[40]

### [1] At the Well States

#### [a] Texas

Texas is probably the most prominent "at the well" jurisdiction, and one of the cases cited most frequently is *Heritage Resources, Inc. v. Nationsbank*.[41] In 2014, the Texas Supreme Court decided *French v. Occidental Permian Ltd.*[42] Occidental Permian Ltd. (Oxy), the defendant-lessee, initially used secondary recovery methods, such as water injection, to enhance production, which Oxy treated as production expenses. Eventually Oxy began tertiary recovery operations by injecting carbon dioxide ($CO_2$) into the reservoir. As a result, the produced casinghead gas was heavily laden with $CO_2$. Oxy processed the gas to create concentrated streams of $CO_2$ for reinjection and to recover the natural gas liquids. Oxy accounted for the cost to remove the $CO_2$ from the casinghead gas as a post-production expense and deducted it to arrive at a value upon which the royalties were paid. The lessors disputed the deduction of that expense.[43]

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[39] *Id.* at 1041.

[40] This section reviews certain seminal and/or recent cases from various jurisdictions. It does not cover all of the jurisdictions with opinions on the topic or all of the relevant cases from any one jurisdiction. There are numerous other papers and articles addressing this subject matter. *See, e.g.*, David E. Pierce, "Royalty Jurisprudence: A Tale of Two States," 49 *Washburn L.J.* 347 (2010); George A. Bibikos & Jeffrey C. King, "A Primer on Oil & Gas Law in the Marcellus Shale States," 4 *Tex. J. Oil, Gas & Energy L.* 155 (2009); Rachel M. Kirk, "Variations in the Marketable-Product Rule from State to State," 60 *Okla. L. Rev.* 769 (2007); Byron C. Keeling & Karolyn King Gillespie, "The First Marketable Product Doctrine: Just What Is the 'Product'?" 37 *St. Mary's L.J.* 1, 31–32 (2005); Owen L. Anderson, "Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically?" 37 *Nat. Resources J.* 547 (1997); Owen L. Anderson, "Calculating Royalty: 'Costs' Subsequent to Production—'Figures Don't Lie, But . . . ,'" 33 *Washburn L.J.* 591 (1994).

[41] 939 S.W.2d 118 (Tex. 1996).

[42] 440 S.W.3d 1 (Tex. 2014).

[43] *Id.* at 2–3.

Highlighting the distinction between "at the well" states like Texas and marketable product states like Kansas, the Texas Supreme Court explained that royalties in Texas are generally "subject to postproduction costs, including . . . treatment costs to render [production] marketable,"[44] and further noted that Oxy argued "that removal of the $CO_2$ is necessary to make the casinghead gas marketable and is therefore a postproduction expense that must be shared by the royalty owners."[45] The court held that the removal of $CO_2$ injected in tertiary operations is a post-production expense that was properly deducted. The court noted that Oxy was not obligated to remove the $CO_2$ from the casinghead gas but, instead, could have chosen to directly reinject the gas into the field, in which case the lessors would not be entitled to royalties on the reinjected gas.[46] By choosing to process the gas, Oxy was creating greater economic benefit to the lessors, who would share in the value of the extracted and marketed NGLs. Moreover, the unit agreement gave Oxy discretion in determining how and whether to conduct the enhanced recovery operations, and since they had benefited from that decision, they must share in the $CO_2$ removal costs.[47] The decision to process the gas also had the overall benefit of encouraging the full recovery of hydrocarbons and precluding waste.[48]

Shortly thereafter, in *Chesapeake Exploration, L.L.C. v. Hyder*, the Texas Supreme Court ruled that Chesapeake Exploration, L.L.C. had improperly deducted post-production costs from the overriding royalties.[49] The lease established "a perpetual, cost-free (except only its portion of production taxes) overriding royalty . . . ."[50] The court concluded that the "cost-free" provision was intended to exclude post-production costs from the overriding royalty interest.[51] This clause was not, however, dispositive of the issue. The lease also allowed the overriding royalty interest owners to take in kind, and where the royalty interest holders elected to take in kind, they would take their share of the produced oil or gas at the well and be responsible

[44] *Id.* at 3 (alteration in original) (quoting *Heritage Res.*, 939 S.W.2d at 122).

[45] *Id.* at 7. The court also noted that "[t]he parties agree[d] that removing contaminants indigenous to the production field, like $H_2S$, from casinghead gas is not part of production, and the royalty owners must share in the expense." *Id.* at 9.

[46] *Id.* at 10.

[47] *Id.*

[48] *Id.* at 10 n.32.

[49] No. 14-0302, 2015 WL 3653446 (Tex. June 12, 2015), *opinion withdrawn and superseded on denial of reh'g*, 483 S.W.3d 870 (Tex. 2016).

[50] 483 S.W.3d at 872.

[51] *Id.* at 875.

for post-production costs. The court stated that though the royalty holders might be subject to post-production costs upon taking their payment in kind, this did "not suggest that they must be subject to those costs when the royalty is paid in cash."[52] The lease also disclaimed the application of *Heritage Resources*, and the court found that such a disclaimer could not "free a royalty of postproduction costs when the text of the lease itself does not do so."[53] As a result, the lease's disclaimer did not dictate the court's conclusion.[54]

### [b] Louisiana

Louisiana has also been an "at the well" state for decades. *Wall v. United Gas Public Service Co.*[55] is an early case in the development of the "at the well" rule. In *Wall*, the lease provided that royalties would be calculated on the "market price." The lessee paid transportation and processing costs to sell the gas two miles downstream and calculated the royalty based on the value of the gas at the well rather than the downstream sale price. The lessor argued the royalty should have been calculated based on the price at which the gas was sold.[56] The Louisiana Supreme Court determined the wellhead was the appropriate point for determining royalty payments.[57] The court also used a comparable sales method to determine whether the royalty paid by the lessee was adequate and noted that if such comparable sales information had not been available, the work-back method would have been appropriate.[58]

In 1960, the U.S. Court of Appeals for the Fifth Circuit considered whether under Louisiana law lessors are expected to "bear any part of the cost of processing,"[59] and determined that reasonable processing costs necessary for creating or adding value to gas may be deducted before calculating royalties.[60] The court also stated that where comparable sales

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[52] *Id.*

[53] *Id.* at 876.

[54] *Id.*

[55] 152 So. 561 (La. 1934).

[56] *Id.* at 562.

[57] *Id.* at 564.

[58] *Id.* at 564–65.

[59] Freeland v. Sun Oil Co., 277 F.2d 154, 155 (5th Cir. 1960).

[60] *Id.* at 159–60.

information is unavailable, the work-back method may be used to arrive at the market value at the well.[61]

### [c] Mississippi

Another leading "at the well" case comes from Mississippi. In *Piney Woods Country Life School v. Shell Oil Co.*, the Fifth Circuit examined the phrase "market value at the well" for computing royalties under Mississippi law.[62] The Fifth Circuit affirmed Shell Oil Co.'s practice of deducting processing costs before calculating royalty payments and defined market value at the well as "market value before processing and transportation."[63]

Similarly, in *Pursue Energy Corp. v. Abernathy*,[64] the Mississippi Supreme Court concluded that although a lessee could "deduct reasonable processing and investment costs from the payments made to royalty owners," in that case it was unreasonable for the oil company to deduct its capital investment costs from royalty payments where the prior owner of the processing plant had already recovered such costs from the royalty owners.[65]

### [d] North Dakota

In *Bice v. Petro-Hunt, L.L.C.*,[66] the North Dakota Supreme Court announced North Dakota would join the majority of states following the "at the well" rule for royalty calculations. In 1983, Gulf Oil Corporation (Gulf) and the lessors entered into a settlement agreement stating that royalties "would be determined by adding all of the sources of revenue from the sale of gas and gas products and subtracting from that total certain costs associated with processing the gas."[67] Petro-Hunt, L.L.C. (Petro-Hunt) acquired Gulf's interest in 1997. The wells did not produce marketable gas, so Petro-Hunt pumped the gas from the field and routed it to tank batteries, which separated oil and water from the gas. The oil,

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[61] *Id.* at 159; *see also* Merritt v. Sw. Elec. Power Co., 499 So. 2d 210 (La. Ct. App. 1986) (allowed deduction of compression costs from royalty where the delivery point for the sale of gas was off the leased premises); Babin v. First Energy Corp., 96-1232 (La. App. 1 Cir. 3/27/97); 693 So. 2d 813, 816 (stating that "[t]he consensus of authority in Louisiana appears to allow lessees to deduct for reasonable costs, but not additional amounts for profit").

[62] 726 F.2d 225 (5th Cir. 1984).

[63] *Id.* at 231.

[64] 2009-CA-01794-SCT, 77 So. 3d 1094 (Miss. 2011).

[65] *Id.* ¶ 17.

[66] 2009 ND 124, 768 N.W.2d 496. For an in-depth analysis of the court's decision in *Bice*, see Pierce, *supra* note 40, at 370–74. *See also* John Burritt McArthur, "Some Advice on Bice, North Dakota's Marketable-Product Decision," 90 *N.D. L. Rev.* 545 (2014).

[67] *Bice*, 2009 ND 124, ¶ 2.

water, and gas were processed at a gas plant, and then the marketable gas was sold at or downstream of the plant tailgate. Petro-Hunt used residue gas processed at the plant to fuel the tank batteries. Petro-Hunt calculated the royalties "based on the market value of the gas at the well," regardless of the royalty clause in each lease.[68] The lessors filed suit claiming Petro-Hunt had underpaid royalties by deducting post-production costs. The district court granted summary judgment in favor of Petro-Hunt, finding that the royalties should be calculated using the work-back method.[69] The North Dakota Supreme Court affirmed and also found the "free use" clause in the leases permitted Petro-Hunt to use the residue gas off the leased premises without paying royalty on the residue gas, and deductions for risk capital and depreciation were not excessive.

More recently, in *Kittleson v. Grynberg Petroleum Co.*, the North Dakota Supreme Court affirmed the principle that the express terms of a lease govern and more specific clauses trump general ones.[70] Where a royalty clause called for payment to a lessor of "the market value at the well for all gas . . . produced from the leased premises . . . ; provided however, that there shall be no deductions [for post-production costs],"[71] the supreme court affirmed the lower court's award of damages for improper royalty deductions to the lessor. The court stated that while the "at the well" language allows deductions of reasonable post-production costs from the sales price received, "the more specific 'no deductions' language qualifies and prevails over [the 'at the well' clause]."[72]

### [e] Montana

For at least three decades before the North Dakota decision in *Bice*, neighboring Montana also used the "at the well" rule. In *Montana Power Co. v. Kravik*, the Montana Supreme Court held that "[w]here no market exists in the field, in the absence of unlawful combination or suppression of price, royalty may be computed upon receipts from the marketing outlet for the products, less the costs and expenses of marketing and transportation."[73] More recently, the U.S. District Court for the District of

[68] *Id.* ¶ 4.

[69] *Id.* ¶ 6.

[70] 2016 ND 44, 876 N.W.2d 443.

[71] *Id.* ¶ 2.

[72] *Id.* ¶ 15.

[73] 586 P.2d 298, 303 (Mont. 1978).

Montana, as affirmed by the Ninth Circuit, relied on *Montana Power* to conclude that Montana is an "at the well" state.[74]

### [f] California

In *Atlantic Richfield Co. v. State*, the California Court of Appeals held royalties were due on the value of oil or gas at the mouth of the well.[75] Atlantic Richfield Co. (Atlantic Richfield), the defendant-lessee, held leases to land belonging to the State of California and initially did not deduct marketing costs.[76] After discovering sour oil and gas, Atlantic Richfield constructed its own treating facilities "rather than sell the sour wet gas to an independent processor at a substantial discount."[77] Atlantic Richfield sought to deduct the price of the treating facilities, and the state brought suit.[78] The court found that "[t]he term 'at the well,' when used with reference to oil and gas royalty valuation, is commonly understood to mean that the oil and gas is to be valued in its unprocessed state as it comes to the surface at the mouth of the well."[79] When the phrase "at the well" is used in conjunction with "market price," the rule in California is that "unless there is clear language to the contrary, the lessor of an oil and gas lease . . . bears its proportionate share of processing costs incurred downstream of the well."[80]

### [g] Pennsylvania

In *Kilmer v. Elexco Land Services, Inc.*,[81] the plaintiff-lessor claimed deduction of post-production costs was impermissible because the royalty statute guaranteed lessors at least one-eighth of the net sales proceeds and the deductions would reduce the royalty payment below that statutory minimum. The Pennsylvania Supreme Court disagreed and confirmed that lessees may deduct post-production costs in computing royalty payments.

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[74] S Bar B Ranch v. Omimex Canada, Ltd., 942 F. Supp. 2d 1058, 1061 (D. Mont. 2013), *aff'd*, 601 F. App'x 569 (9th Cir. 2015) (mem.).

[75] 262 Cal. Rptr. 683 (Ct. App. 1989). For a more in-depth examination of *Atlantic Richfield*, see Owen L. Anderson, "Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 2," 37 *Nat. Resources J.* 611, 659–62 (1997).

[76] *Atl. Richfield*, 262 Cal. Rptr. at 686.

[77] *Id.* at 686–87.

[78] *Id.* at 687.

[79] *Id.* at 688.

[80] *Id.*

[81] 990 A.2d 1147 (Pa. 2010).

The court defined "royalty" as "[t]he landowner's share of production, free of expenses of production"[82] and distinguished production costs from post-production costs.[83] To determine the value of gas at the wellhead, the court permitted the net-back method, allowing the costs of getting the natural gas from the wellhead to the market to be deducted from the sales price.[84]

In 2012, the Pennsylvania Superior Court in *Katzin v. Central Appalachia Petroleum* declined to declare an oil and gas lease void and in violation of the Guaranteed Minimum Royalty Act because it was allegedly vague with respect to what expenses could be deducted before calculating royalties.[85] Instead, the court noted that a promise to take actions necessary to carry out the purpose of the contract is implied in every contract, and therefore held that it must "imply a promise by [the lessee] . . . to comply with the mandates of the [Guaranteed Minimum Royalty Act]."[86] The holding left open the possibility that the lessor could bring a claim against the lessee for breach of the implied promise by improperly allocating post-production expenses.

Despite apparently following the "at the well" rule, the law in Pennsylvania is somewhat unsettled. For example, last year in *Pollock v. Energy Corp. of America*,[87] a jury found in favor of a class of plaintiff-lessors on claims that the defendant-lessee had improperly deducted interstate pipeline costs and marketing expenses from their royalties, and the U.S. District Court for the Western District of Pennsylvania denied Energy Corporation of America's (ECA) post-trial motions. The district court had previously granted summary judgment against ECA for its deduction of interstate transportation charges incurred after ECA had transferred title of the gas to third-party purchasers.[88] The court had also previously denied ECA's motion for summary judgment, stating that although *Kilmer* allows marketing cost deductions from royalties, it was ambiguous whether ECA or

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[82] *Id.* at 1157 (alteration in original) (quoting Patrick H. Martin & Bruce M. Kramer, *Williams & Meyers, Manual of Oil and Gas Terms* (2009)).

[83] *Id.* at 1157–58.

[84] *Id.* at 1158.

[85] 39 A.3d 307, 309 (Pa. Super. Ct. 2012).

[86] *Id.*

[87] No. 2:10-cv-01553, 2015 WL 3795659 (W.D. Pa. June 18, 2015), *appeal docketed*, No. 15-2648 (3d Cir. July 9, 2015).

[88] *Id.* at *1.

its marketing subsidiary actually incurred the marketing costs.[89] ECA has since appealed the case to the U.S. Court of Appeals for the Third Circuit.

### [h] Kentucky

Kentucky recently considered whether to adopt the marketable product rule and, instead, opted for the "at the well" approach. In *Baker v. Magnum Hunter Production, Inc.*,[90] the Kentucky Supreme Court interpreted lease provisions under which the defendant-lessee agreed "[t]o pay Lessor one-eighth of the market price at the well for gas sold or for the gas so used from each well off the premises."[91] In holding that Kentucky does not apply the marketable product method of royalty calculations, the Kentucky Supreme Court primarily relied on three of its prior decisions.[92] First, in *Warfield Natural Gas Co. v. Allen*[93] and *Rains v. Kentucky Oil Co.*,[94] the court held that where the lease was silent as to how or where the production was to be valued, the presumption is that the "royalty is to be valued 'at the well side.' "[95] Similarly, in *Reed v. Hackworth*,[96] the court found that where the lease was "silent as to the place of market and the price of the gas," deduction of the transportation charge was not unreasonable to determine the "at the well" value of the gas.[97] Thus, in *Baker*, the Kentucky Supreme Court reasoned that these prior decisions made it clear that the lessor's royalty is based on the value of the raw gas captured at the well, and where a lease is silent on the measure of production, that production should be measured using the "at the well" approach absent some clear indication to the contrary.[98]

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[89] *Id.* at *2.

[90] 473 S.W.3d 588 (Ky. 2015).

[91] *Id.* at 590.

[92] *Id.* at 592–95.

[93] 88 S.W.2d 989 (Ky. 1935).

[94] 255 S.W. 121 (Ky. 1923).

[95] *Baker*, 473 S.W.3d at 593.

[96] 287 S.W.2d 912 (Ky. 1956).

[97] *Baker*, 473 S.W.3d at 593 (quoting *Reed*, 287 S.W.2d at 913).

[98] *Id.* at 594; *see also* Appalachian Land Co. v. EQT Prod. Co., 468 S.W.3d 841, 847 (Ky. 2015) ("absent a specific lease provision apportioning severance taxes, lessees may not deduct severance taxes or any portion thereof prior to calculating a royalty value").

## [2] Marketable Product States

### [a] Oklahoma

There are several Oklahoma cases on this topic.[99] Perhaps the Oklahoma case most often cited is *Mittelstaedt v. Santa Fe Minerals, Inc.*, where the lessee deducted a portion of transportation, blending, dehydration, and compression fees incurred after gas was moved off lease.[100] The Oklahoma Supreme Court held that while costs associated with creating a marketable product are not deductible, some post-production costs could be deducted depending on the circumstances.[101] A lessor is responsible for a proportionate share of costs if the lessee can prove "(1) that the costs enhanced the value of an already marketable product, (2) that such costs are reasonable, and (3) that actual royalty revenues increased in proportion with the costs assessed against the nonworking interest."[102]

Another often-cited case from Oklahoma is *Howell v. Texaco Inc.*, involving an affiliate or "intra-company" contract for the sale of the gas collected at the wellhead.[103] The court found that royalty payments could not be based on an intra-company, non-arm's length wellhead gas sale.[104] Royalty values should be "based on [either] the prevailing market price or the work-back method, whichever one results in the higher market value."[105] Prevailing market price may be determined by "[p]roof of arms'-length [sic] sales from other wells in the vicinity."[106] The work-back method calculates the market value at the wellhead "by subtracting allowable costs and expenses from the first downstream, arm's-length sale."[107] There are a number of other recently decided and pending cases in Oklahoma, but *Mittelstaedt* is still good law.

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[99] For a more in-depth discussion of Oklahoma royalty case law, see John W. Broomes, "Waste Not, Want Not: The Marketable Product Rule Violates Public Policy Against Waste of Natural Gas Resources," 63 *U. Kan. L. Rev.* 149, 157–65 (2014).

[100] 1998 OK 7, ¶ 3, 954 P.2d 1203.

[101] *Id.* ¶ 2.

[102] *Id.*

[103] 2004 OK 92, 112 P.3d 1154.

[104] *Id.* ¶ 18.

[105] *Id.* ¶ 22.

[106] *Id.* ¶ 19.

[107] *Id.* ¶ 20.

### [b] Arkansas

Arkansas law is arguably unsettled; some commentators suggest it is likely to adopt the marketable product rule approach, while others suggest it already has.[108] In *Clear Creek Oil & Gas Co. v. Bushmiaer*,[109] the Arkansas Supreme Court examined a lease requiring royalties based on "the market price of royalty gas at the well."[110] Despite evidence of other gas sales from the same area, the court found that there was no market for the gas at the well.[111] The court then held that "if there be no market value at the place of delivery, the value of the goods or other product should be determined at the nearest place where they have a market value, deducting the extra expense of delivering them there."[112] The court then essentially applied a work-back methodology because it found that the royalties should be paid on the downstream sales price less the transportation costs.

In *Hanna Oil & Gas Co. v. Taylor*, the Arkansas Supreme Court examined a lease requiring royalties based on "the proceeds received . . . at the well for all gas (including all substances contained in such gas) . . . ."[113] Relying on the term "proceeds"—as distinguished from the phrase "net proceeds"—the court held the lessee could not deduct compression costs.[114] In that case, however, the compression at issue was a relatively new expense. Originally, the natural well pressure had been sufficient to satisfy the first purchaser's specifications for its pipeline. Over time, the pressure in the wells fell and compression became necessary. While this holding arguably anticipates a marketable product rule, the short opinion focuses on the lease language, not the implied duty to market. And in 2009, the U.S. District Court for the Eastern District of Arkansas found it is still unclear whether Arkansas has committed to being a marketable product rule state.[115]

### [c] New Mexico

New Mexico has been previously classified as following the "at the well" approach. However, following the New Mexico Supreme Court's decision

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[108] *See, e.g.*, Kirk, *supra* note 40, at 780–83.

[109] 264 S.W. 830 (Ark. 1924).

[110] *Id.* at 831.

[111] *Id.* at 832.

[112] *Id.*

[113] 759 S.W.2d 563, 564 (Ark. 1988).

[114] *Id.* at 565.

[115] Riedel v. XTO Energy, Inc., 257 F.R.D. 494, 505 (E.D. Ark. 2009) (citing Edward B. Poitevent, II, "Post-Production Deductions from Royalty," 44 *S. Tex. L. Rev.* 709, 747 (2003)).

in *Davis v. Devon Energy Corp.*,[116] which ruled on three consolidated class action claims, many commentators place New Mexico in the marketable product rule category. The New Mexico Supreme Court did not actually adopt the marketable product doctrine and, in fact, expressly noted that "the question of whether and under what circumstances the marketable product rule applies in New Mexico is not ripe for review at this time."[117] The court, however, did allow the three cases to proceed to trial on marketable product theories.[118]

### [d] Michigan

In *Schroeder v. Terra Energy Ltd.*, the Michigan Court of Appeals held that the costs a lessee incurred in transporting, treating, and marketing were deductible from royalties payable on "gross proceeds at the wellhead."[119] The court concluded the language used in the lease was "sufficiently unambiguous"[120] and noted this lease construction had "the virtue of establishing a uniform location for ascertaining the value of the gas, namely, its value at the wellhead."[121] The court concluded that having a uniform location for determining value was preferable to valuing the gas at "whatever location . . . the gas ultimately becomes marketable, thereby resulting in potentially different valuations for the product of the same well."[122]

Following this decision, the Michigan legislature passed a statute applicable to gas leases entered into after March 28, 2000, that prohibits lessees from deducting "any portion of postproduction costs unless the lease

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[116] 2009-NMSC-048, 218 P.3d 75.

[117] *Id.* ¶ 15; *see also id.* ("nothing in this opinion should be construed as either the recognition or disapproval of the marketable condition rule, its scope, or its applicability").

[118] *Id.* ¶ 25; *see also* Anderson Living Trust v. ConocoPhillips Co., 952 F. Supp. 2d 979, 1028 n.7 (D.N.M. 2013) ("The Court believes that, if and when the Supreme Court of New Mexico determines that the existence of the marketable condition rule is ripe for review, it will find that the rule is included in oil-and-gas contracts as part of the implied duty to market."); Anderson Living Trust v. WPX Energy Prod., LLC, 312 F.R.D. 620, 630 (D.N.M. 2015) (predicting that "the New Mexico Supreme Court [would] find that, included within the implied duty to market in New Mexico, is the marketable condition rule" (quoting *Anderson*, 952 F. Supp. 2d at 1028 n.7)).

[119] 565 N.W.2d 887 (Mich. Ct. App. 1997). For a more thorough examination of *Schroeder*, see Anderson, *supra* note 75, at 664.

[120] *Schroeder*, 565 N.W.2d at 894.

[121] *Id.* at 893 n.5.

[122] *Id.*

explicitly allows for the deduction of postproduction costs."[123] However, for leases explicitly permitting deduction of post-production costs, the statute states that the lessee may only deduct costs for certain items listed in the statute "unless the lease explicitly and specifically provides for the deduction of other items."[124]

### [e] Nevada

Nevada is commonly recognized as having adopted the marketable product rule by statute, but the statutory language focuses on production costs being non-deductible and allows for deduction of certain downstream costs. Under the statute, "[t]he lessee is liable for all of the costs of production,"[125] and "[t]he lessor's interest, the mineral owner's royalty interest and the [ORRI] must not be decreased by the costs of production."[126] "Costs of production" is defined as "all costs incurred for the exploration and development of, primary or enhanced recovery of oil or gas from, and operations associated with the abandonment of, an oil or gas well . . . ."[127] The term includes transportation of oil to storage tanks or gas into the pipeline for delivery but specifically excludes "the reasonable and actual direct costs associated with transporting oil from storage tanks to the market, gas from the point of entry into the pipeline to the market or the processing of gas in a processing plant."[128]

### [f] Wyoming

Wyoming is another jurisdiction that has statutorily addressed the issue. Wyoming has defined "royalty" as a "mineral owner's share of production, free of the costs of production,"[129] and broadly defined "costs of production" as "all costs incurred for exploration, development, primary or enhanced recovery and abandonment operations including, but not limited to lease acquisition, drilling and completion, pumping or lifting, recycling, gathering, compressing, pressurizing, heater treating, dehydrating, separating, storing or transporting the oil to the storage tanks or the gas into the market pipeline."[130] However, the statute expressly excludes from production

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[123] Mich. Comp. Laws § 324.61503b(1).

[124] *Id.*

[125] Nev. Rev. Stat. § 522.115(1)(a).

[126] *Id.* § 522.115(1)(b).

[127] *Id.* § 522.115(3).

[128] *Id.*

[129] Wyo. Stat. Ann. § 30-5-304(a)(vii).

[130] *Id.* § 30-5-304(a)(vi).

costs "the reasonable and actual direct costs associated with transporting the oil from the storage tanks to market or the gas from the point of entry into the market pipeline or the processing of gas in a processing plant."[131]

In *Wold v. Hunt Oil Co.*, the U.S. District Court for the District of Wyoming held the Wyoming statute barred deduction from an overriding royalty of gathering costs as costs of production.[132] Similarly, in *Cabot Oil & Gas Corp. v. Followill*, the Wyoming Supreme Court concluded that "gathering," as it is used in the statute, means "to collect gas and move it to a point where it can be processed or transported to the user."[133] Transportation charges incurred prior to the gas's entry into an interstate pipeline were costs of production and not deductible from royalties.[134] The Wyoming Supreme Court also agreed with *Wold*'s conclusion that "the Wyoming legislature has departed from the methodologies employed by other jurisdictions and specifically excluded all charges between the wellhead and the market pipeline except those specifically excluded from the definition."[135]

### [3] Marketable Product and Marketable Location States

#### [a] Colorado

In *Garman v. Conoco, Inc.*,[136] the Colorado Supreme Court considered whether an ORRI owner could be required to share in post-production costs. The court found that the duty to market was implied in every oil and gas lease and, based on that duty, held that the lessee was required to bear expenses necessary to obtain a marketable product.[137] The court further held that a lessee could deduct costs incurred to enhance the value of an already marketable product.[138]

In *Rogers v. Westerman Farm Co.*,[139] the Colorado Supreme Court departed from prior case law and invoked the implied duty to market to require a lessee to bear the costs both to produce a marketable product and

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[131] *Id.*

[132] 52 F. Supp. 2d 1330, 1336–37 (D. Wyo. 1999).

[133] 2004 WY 80, ¶ 15, 93 P.3d 238.

[134] *Id.*

[135] *Id.* ¶ 12.

[136] 886 P.2d 652 (Colo. 1994).

[137] *Id.* at 659.

[138] *Id.* at 661.

[139] 29 P.3d 887 (Colo. 2001).

to deliver it to market.[140] The leases provided for the lessee to pay royalties at the well, and the parties agreed the gas required gathering, compression, and dehydration to enter into the pipeline.[141] The court found that the "at the well language" was silent as to all costs and their allocation, and when a lease is silent, the implied covenant to market obligates the lessee to make the oil or gas marketable with respect to both "condition" and "location."[142]

Several cases have since cited *Rogers*. For example, in 2005 the Colorado Court of Appeals applied the *Rogers* holding in *Savage v. Williams Production RMT Co.*, where the court found improper deductions for processing and transportation costs.[143] Last year, the court of appeals in *Patterson v. BP America Production Co.* affirmed a jury verdict finding, among other things, that the evidence was sufficient to support the finding that the first market for the gas was downstream of the well.[144]

#### [b] West Virginia

The only other jurisdiction following the Colorado condition and location application of the marketable product rule is West Virginia. In *Wellman v. Energy Resources, Inc.*,[145] the West Virginia Supreme Court expressly adopted the marketable product rule, stating that "a lessee impliedly covenants that he will market oil or gas produced" and that "the lessee should bear the costs associated with marketing products produced under a lease."[146] Thus, the court held that "unless the lease provides otherwise, the lessee must bear all costs incurred in exploring for, producing, marketing, and transporting the product to the point of sale."[147]

In 2006, the West Virginia Supreme Court elaborated on its approval of the marketable product rule in *Estate of Tawney v. Columbia Natural*

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[140] For an in-depth look at *Rogers*, see Pierce, *supra* note 40, at 358–64.

[141] *Rogers*, 29 P.3d at 892.

[142] *Id.* at 902, 906.

[143] 140 P.3d 67, 71 (Colo. App. 2005).

[144] 2015 COA 28, ¶ 64, 360 P.3d 211, *cert. denied*, No. 15SC246, 2015 WL 5934693 (Colo. Oct. 13, 2015) (mem.); *see also* Lindauer v. Williams Prod. RMT Co., 2016 COA 39, ¶ 53, 2016 WL 908452 (as of the date of this chapter, the opinion had not yet been released for publication) (permitting operator deduction of reasonable costs of transporting gas beyond the first commercial market to downstream markets and concluding that those costs do not have to enhance the value of the gas to be deductible).

[145] 557 S.E.2d 254 (W. Va. 2001); *see* Anderson, *supra* note 30, at § 1.04.

[146] *Wellman*, 557 S.E.2d at 265.

[147] *Id.*

*Resources, L.L.C.*,[148] where several thousand lessors argued that the lessee had failed to disclose that post-production costs had been deducted from royalty payments. The court concluded that various royalty clauses were ambiguous and without additional clarifying language in the lease, the lessee could not deduct any post-production costs.[149] A lease allocating post-production costs between a lessor and lessee "must expressly provide that the lessor shall bear some part of the costs incurred between the wellhead and the point of sale, identify with particularity the specific deduction the lessee intends to take from the lessor's royalty . . . , and indicate the method of calculating the amount to be deducted . . . ."[150]

More recently, in *W.W. McDonald Land Co. v. EQT Production Co.*,[151] a federal district court strictly interpreted the *Tawney* requirements to find that the lessees had a duty to bear all costs incurred until the gas reached the downstream, third-party market.[152] The court, however, rejected the plaintiff-lessors' argument that royalties should be calculated based on the higher gas volume measured at the wellhead instead of the smaller volume sold at the interstate pipeline connection, holding that it would be "illogical and inequitable" to require lessees to pay royalties on gas that was never sold.[153]

## § 18.04 Royalties on Federal and Indian Oil and Gas Leases

The federal government is the largest royalty interest owner in the country.[154] Under the Mineral Leasing Act of 1920 (MLA)[155] and the Mineral Leasing Act for Acquired Lands,[156] the Bureau of Land Management (BLM) is responsible for oil and gas leasing on approximately 564 million acres of BLM, national forest, and other federal lands, as well as state and private

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[148] 633 S.E.2d 22 (W. Va. 2006).

[149] *Id.* at 28.

[150] *Id.* at 30.

[151] 983 F. Supp. 2d 790 (S.D. W. Va. 2013), *opinion clarified* (Jan. 21, 2014).

[152] *Id.* at 802.

[153] *Id.*

[154] For a timely and more complete explanation of the issues discussed in this section, see Judith M. Matlock, "ONRR Royalty Update: The Marketable Condition Rule and Unbundling Pending RIK Imbalance Resolution Litigation," *Federal Offshore Regulatory Enforcement* 13A-1 (Rocky Mt. Min. L. Fdn. 2016); Peter J. Schaumberg, "ONRR Royalty Update: Proposed Regulations for Oil and Gas Valuation; Civil Penalties," *Federal Offshore Regulatory Enforcement* 13B-1 (Rocky Mt. Min. L. Fdn. 2016).

[155] 30 U.S.C. §§ 181–263.

[156] *Id.* §§ 351–360.

surface lands where the federal government has retained mineral rights.[157] Federal royalties are based on leases using provisions prepared under the Secretary of the Interior's power to implement the MLA, which requires payment based on the "amount or value of the production removed or sold from the lease."[158] The federal regulations implementing the MLA require lessees to put oil and gas into marketable condition largely at their own expense; however, the regulations allow certain deductions.[159]

The Office of Natural Resources Revenue (ONRR) is responsible for managing revenues associated with onshore federal and Indian leases and offshore Outer Continental Shelf leases. In 2015 alone, ONRR reported $915,071,846.18 in royalties from gas recovered on federal onshore leases and $135,002,710.26 in royalties paid to Indian royalty owners. ONRR reported $1,269,596,133.67 in royalties from oil recovered on federal onshore leases and $601,836,549.94 in royalties paid to Indian royalty owners.[160]

### [1] The Current Regulations and Unbundling of Costs

As part of its charge to manage revenues associated with federal leases, ONRR performs compliance reviews of federal lessees.[161] Enforcement efforts are currently focused on royalties due on the production of gas. The current gas valuation regulations were adopted in 1988 and define "marketable condition" as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area."[162]

Federal lessees are permitted to deduct transportation and processing allowances to account for costs they might incur that are not necessary to make the gas marketable.[163] Of course, "[f]ederal lessees may not include in their transportation and processing allowances, any costs incurred to put their gas into marketable condition," and "[i]f they sell their gas before

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[157] *See* BLM, "Questions and Answers About Leasing," http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/questions_and_answers.html.

[158] 30 U.S.C. § 226(b)(1)(A).

[159] *See* 30 C.F.R. pt. 1206.

[160] *See* ONRR, Statistical Information, Reported Revenues by Category for Fiscal Year 2015, http://statistics.onrr.gov/ReportTool.aspx.

[161] For a more thorough examination of recent developments relating to the marketable condition rule and the associated unbundling requirement, see Matlock, *supra* note 154.

[162] 30 C.F.R. § 1206.151.

[163] *Id.* §§ 1206.156, .158. "Allowance" is defined as "a deduction in determining value for royalty purposes." *Id.* § 1206.151.

it is in marketable condition, they must gross up [(i.e., increase)] the value to the extent their gross proceeds were reduced by costs to put their gas into marketable condition."[164]

Consequently, federal lessees should distinguish between costs that are required to make the production marketable and those that are not. Practically, however, the particular costs incurred are typically "bundled" in gathering, transportation, or processing deductions, charges, or fees. As a result, federal lessees must "unbundle" the costs into allowed and disallowed costs or take no transportation and processing allowances. This is true even for those federal lessees who sell their production at the wellhead.[165]

In addition to the laborious task of identifying and unbundling the particular costs involved, federal lessees should consider the conflicting authority concerning what costs are required to put the production in a marketable condition under the regulations. For example, in 1995, the Minerals Management Service (MMS), a predecessor to ONRR, issued a Compression Guidance Memorandum indicating that compression costs incurred before the pipeline inlet immediately after the BLM or MMS approved measurement point were costs necessary to make the gas marketable, but compression costs incurred thereafter were not and were "an allowable deduction from royalty as part of the lessee's cost of transportation."[166] The following year, the MMS repeated this guidance.[167] This guidance, however, was not followed by decisions from the Assistant Secretary of the U.S. Department of the Interior, which were affirmed on appeal.[168] At issue were the transportation deductions taken by Devon Energy Corporation (Devon) on production from the Powder River Basin. Ultimately, the court affirmed the decisions requiring Devon to bear the compression costs required to boost the pressure of the gas to the mainline pipeline specifications. However, as Devon was able to show the gas reached that pressure prior to the inlet to the mainline pipeline, it was

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[164] Matlock, *supra* note 154, at 13A-2; *see* 30 C.F.R. § 1206.151 (definition of "gross proceeds").

[165] Matlock, *supra* note 154, at 13A-17. For a more through discussion of the unbundling requirement, see *id.* at 13A-17 to 13A-27.

[166] *Id.* at 13A-3 (quoting the Compression Guidance Memorandum).

[167] *Id.* (citing MMS Dear Payor Letter dated April 22, 1996).

[168] *Id.* (citing Devon Energy Corp. v. Norton, No. 1:04-cv-00821, 2007 WL 2422005 (D.D.C. Aug. 23, 2007), *aff'd sub nom.* Devon Energy Corp. v. Kempthorne, 551 F.3d 1030 (D.C. Cir. 2008)).

allowed to deduct compression costs incurred downstream of the point where the gas first reached the requisite pressure.[169]

Proper application of the current regulations, therefore, presents challenges in terms of both varying interpretations of the regulations and unbundling the costs at issue to make sure they are properly categorized for purposes of the allowances and calculating the royalties.

### [2] Consolidated Federal Oil and Gas and Federal and Indian Coal Valuation Reform

On July 1, 2016, ONRR published a new rule significantly altering regulations applicable to oil and gas valuation for royalty reporting and payment by oil and gas lessees on federal lands onshore and on the Outer Continental Shelf.[170]

The regulations do not change the entire method by which oil sales are valued under the prior regulations. Instead, the regulations largely eliminated what ONRR considered unused valuation options and attempt to make the oil rule consistent with the rules relating to gas valuation. However, the most significant change under the rule is the "default provision," under which ONRR may determine the value of the production if it determines that the lessee did not do so properly.[171]

The rule also restructures the gas valuation regulations to conform them to the general structure of the previously revised oil valuation regulations.[172] The rule does not dramatically change the valuation of arm's-length gas sales. If the lessee or its affiliate sells unprocessed gas, residue gas after processing, or gas plant products resulting from processing, under an arm's-length contract, the value of the gas is based on the arm's-length gross proceeds.[173] However, where an affiliate is selling the gas or gas plant products under an arm's-length contract, the federal lessee has the option of choosing the valuation method applicable to sales not under an

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[169] *See id.* at 13A-3 to 13A-6 (discussing the opinion).

[170] *See* Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, 81 Fed. Reg. 43,338 (July 1, 2016) (to be codified at 30 C.F.R. pts. 1202, 1206) (effective Jan. 1, 2017). For an in-depth examination of the proposed version of this regulation, see Schaumberg, *supra* note 154 (although this source discusses the proposed rule, the final rule is substantively very similar to the proposed rule). This chapter does not address the rule's effect on coal valuation.

[171] *See* Schaumberg, *supra* note 154, at 13B-6.

[172] *Id.* at 13B-9.

[173] *Id.*

arm's-length contract rather than having to determine the affiliate's gross proceeds to the sales point and adjust for transportation.[174]

The rule, however, adopts an entirely new methodology for valuing non-arm's-length sales of gas and gas plant products. For such gas sales, the rule eliminates benchmarks, which are a series of indicators of market value, and instead uses valuation methodologies based on how gas is sold using the first arm's-length sale price, optional index prices, or weighted average pool prices.[175] The rule also consolidates the definitions applicable to both oil and gas valuation. Notably, the definition of "gathering" for oil and gas produced from Outer Continental Shelf leases declares any movement of production from the wellhead to a platform as non-deductible gathering, as opposed to a deductible transportation cost, in determining the royalty value.[176]

### [3] Proposed Rule Changes Concerning Royalties on Flared or Vented Gas and Setting the Royalty Percentage

On February 8, 2016, the BLM published a proposed rule that would impact primarily two areas: (1) the royalties due on natural gas losses, such as where gas is vented, flared, or leaked during production activities, from onshore federal and Indian leases; and (2) the royalty percentage allowable under federal leases.[177]

The MLA requires the BLM to ensure lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land . . . ."[178] The existing regulations relating to venting, flaring, and royalty-free use of gas were promulgated in 1979 in a Notice to Lessees and Operators (NTL-4A).[179] Currently, "[u]nder NTL-4A, operators must apply to the BLM on a case-by-case basis for approval to flare royalty-free, based on economic

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[174] *Id.*

[175] *See* 81 Fed. Reg. at 43,346. For a more detailed explanation of how the proposed version of the regulations would practically affect royalty calculations, see Schaumberg, *supra* note 154, at 13B-9 to 13B-17.

[176] Schaumberg, *supra* note 154, at 13B-5.

[177] *See* Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 6616 (proposed Feb. 8, 2016) (to be codified at 43 C.F.R. pts. 3100, 3160, 3170).

[178] 30 U.S.C. § 225.

[179] U.S. Dep't of the Interior, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, "Royalty or Compensation for Oil and Gas Lost" (NTL-4A Jan. 1, 1980); *see* 44 Fed. Reg. 76,600 (Dec. 27, 1979) (notice that NTL-4A superseded and revoked NTL-4).

criteria."[180] The proposed rule is anticipated to increase the amount of royalties federal lessees are required to pay for gas that is flared, vented, or otherwise lost.

The proposed rule's asserted purpose is to clarify when flared or vented natural gas is subject to royalties.[181] "A loss of gas would be deemed unavoidable," and therefore royalty-free, "when an operator has complied with all applicable requirements and taken prudent and reasonable steps to avoid waste, and the gas is lost from [certain] specified operations or sources," subject to some further limits.[182] "A loss of gas would also be deemed unavoidable when gas is flared . . . from a well that is not connected to gas capture infrastructure, provided the BLM has not otherwise determined that the loss of gas is avoidable . . . ."[183] Conversely, "[a]ll losses of gas not specifically found to be unavoidable would be considered avoidable and subject to royalties."[184]

Additionally, under current law, the BLM must set royalty rates for noncompetitive leases at 12.5% or one-eighth.[185] However, while the MLA allows the BLM to set a royalty rate of 12.5% or greater for competitive leases,[186] the BLM's existing regulation sets a flat rate of 12.5% for all new competitive leases.[187] The proposed rule purports to do three things to the royalty rates applicable to onshore oil and gas leases: (1) clarify that the royalty rate on all existing leases would remain at the same rate prescribed in the lease or regulations applicable at the time of lease issuance; (2) specify the fixed, statutory rate of 12.5% for all noncompetitive leases issued after the rule's effective date; and (3) for competitive leases issued after the effective date of the rule, align the rule text with the corresponding MLA text, allowing the BLM to set royalty rates at or above 12.5%.[188]

As of the date of this chapter, the final rules had not been released, so federal lessees would be wise to continue to monitor the proposed rules and be ready to implement any necessary modifications.

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[180] 81 Fed. Reg. at 6617.

[181] *Id.* at 6616.

[182] *Id.* at 6620.

[183] *Id.*

[184] *Id.*

[185] 30 U.S.C. § 226(c)(1).

[186] *Id.* § 226(b)(1)(A).

[187] 43 C.F.R. § 3103.3-1(a)(1).

[188] 81 Fed. Reg. at 6624.