Chapter 9
The Shale Pay: Recent Trends in Royalty Claims and Emerging Issues Surrounding Wet Gas and Natural Gas Liquids

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In recent years, there have been a number of royalty disputes in state and federal courts in the Appalachian states, including Pennsylvania, Ohio, West Virginia, Virginia and Kentucky. Courts in these states have continued to develop their body of oil and gas law, addressing the proper royalty calculation under various lease forms and what constitutes the permissible scope of post-production cost deductions. Most recently, there has been an increase in class action royalty disputes, a significant and evolving area of law that raises issues regarding post-production cost deductions, allocation of these deductions, and affiliate transactions.
Additionally, in the last few years, when the industry has seen declining natural gas prices, there has been a strong focus on the production of “wet gas” or liquid rich gas in the Appalachian Basin region. Wet gas contains constituents that, if separated, have substantial independent and stand-alone marketability and value. Given the natural gas industry’s intent to capture the additional value that wet gas has in the marketplace, royalty litigation in the Appalachian Region will likely naturally evolve and begin to focus on the calculation of royalties for wet gas.

§ 9.01. Recent Trends in Appalachian Royalty Cases.


When calculating royalties paid under an oil and gas lease, there are two approaches to the treatment of post-production cost deductions from those royalty payments. Jurisdictions that have considered the issue are split. The majority of jurisdictions, including Pennsylvania, that have developed a body of law regarding this issue calculate royalties by applying the netback method of calculating royalties. The netback method follows the “at the well” or “at the wellhead” rule, allowing the deduction of post-production costs after the gas reaches the wellhead.¹ With this method, both the lessor and the lessee share proportionately in the costs of post-production — the costs that allow the lessee to typically sell the gas at a higher price and the lessor to typically collect a higher royalty payment. Generally, in these jurisdictions, post-production cost deductions are permitted where the oil and gas lease at issue contains reference to post-production costs or language to the effect of “at the well” or “at the wellhead.”

The minority of jurisdictions that have ruled on post-production cost deductions follow the marketable product doctrine, which does not generally permit the deduction of most post-production costs from a lessor’s royalty payment because the royalty is calculated based on the price of gas after it is in a marketable condition.² After the gas reaches that marketable condition, any subsequent post-production costs may be deducted. For ex-

¹ 3-6 Williams & Meyers, Oil and Gas Law, § 645.2 (2014).
² Id.
ample, courts in marketable product jurisdictions have found that the following language permits post-production cost deductions only after the gas is in a marketable condition: “gross proceeds received at the well,” “market price at the well,” “proceeds at the well,” and “market value at the well.” West Virginia applies an extreme variation of the marketable product doctrine, the “point of sale” approach, where no post-production costs between the wellhead and the point of sale may be deducted from the royalty. West Virginia only allows a narrow exception whereby deductions are permitted if the oil and gas lease at issue specifically identifies the deductions and the method for calculating those deductions.


Pennsylvania’s Minimum Royalty Act (MRA), initially enacted in 1979 and amended recently in July 2013, guarantees all royalty owners of oil and gas leases at least a one-eighth royalty of any oil, natural gas, or gas recovered or removed from the leased property. The MRA states that any oil and gas lease that does not include the minimum royalty will be escalated to include the one-eighth minimum royalty when the original state of any well drilled pursuant to such lease is altered. The recent amendments to the MRA added certain royalty and royalty check stub responsibilities for interest owners of oil and gas leases. It added definitions for “check stub,” “division order,” “interest owner,” and “McF,” as well as creating detailed requirements for information that must be included on all check stubs or otherwise attached to the form of royalty payment.

Significantly, the MRA does not contain any language regarding the permissibility of post-production cost deductions from royalty payments. The MRA does not define post-production costs or explain how deductions of such may affect the guaranteed minimum royalty. However, in March 2010, the Pennsylvania Supreme Court began to fill that void by indicating

4 Estate of Tawney, 633 S.E.2d 22 (W. Va. 2006).
6 Id.
that it would follow the netback method of calculating royalties at the well, which allows post-production cost deductions from royalty payments.\(^7\)

In *Kilmer v. Elexco Land Servs., Inc.*, the Pennsylvania Supreme Court rejected landowners’ arguments that had challenged the validity of oil and gas leases that expressly allowed deductions for post-production costs, including gathering, compression, dehydration, treatment, marketing, processing and line loss. The landowners took the position that Pennsylvania’s MRA precluded the lessees from deducting post-production costs because the deductions resulted in a royalty payment less than one-eighth. The court held that the term “royalty” should be interpreted according to oil and gas industry practices, which indicated that the lessor did not share in the costs of production but did share in the costs incurred after production. Specifically, the court found that post-production costs include “production or gathering taxes, costs of treatment of the product to render it marketable, costs of transportation to the market.”\(^8\)

Pennsylvania courts have interpreted *Kilmer* to mean that Pennsylvania follows the netback method or at the well rule, rejecting various attempts to distinguish oil and gas leases.\(^9\) Although the lease at issue in *Kilmer* specifically enumerated certain post-production costs that the lessee was permitted to deduct, that was not an exhaustive list of the type of post-production costs that may be deducted generally. In fact, the Pennsylvania Supreme Court specifically stated that post-production costs are, broadly, “expenditures from when the gas exits the ground until it is sold.”\(^10\) As confirmation of that broad interpretation of post-production costs, the Pennsylvania Superior Court held that, even where the language of an oil and gas lease is vague and does not expressly authorize post-production cost

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\(^7\) *Kilmer v. Elexco Land Servs., Inc.*, 990 A.2d 1147 (Pa. 2010).

\(^8\) *Kilmer*, 990 A.2d at 1157.


\(^10\) *Kilmer*, 990 A.2d at 1149.
deductions, the deductions are permitted as consistent with the customs and practice of the oil and gas industry. However, a Pennsylvania trial court in Allegheny County recently attempted to limit the reach of Kilmer by finding that where certain permitted post-production costs are specifically listed in the lease as permissible deductions, other types of post-production costs may not be deducted.

It is likely that Pennsylvania courts will continue to clarify lease language regarding post-production costs in part by applying principles of contract law and interpretation. So, for example, despite the Kilmer decision and its progeny, if an oil and gas lease expressly prohibits post-production cost deductions from the royalty payment, then the terms of the lease will likely be upheld. However, it is more likely that, rather than leases that explicitly state all post-production costs shall be deducted or shall not be deducted, there will be a so-called gray area in the leases. Accordingly, that is where recent Pennsylvania litigation has focused and where upcoming litigation is expected – determining more nuanced and specific issues regarding post-production cost deductions.


In Kilmer, the Supreme Court broadly defined post-production costs and, generally, the decision has been interpreted to mean that Pennsylvania follows the netback method or at the well rule for calculating royalties and allowing deductions of post-production costs. Pennsylvania courts have since been developing law regarding the permissibility of various types of post-production costs, including those associated with affiliate transactions, those not specifically listed in the lease at issue, and those where the costs were allocated rather than calculated. Recently the royalty calculation issues presented to Pennsylvania courts have emphasized class action challenges by landowners who allege that they have been underpaid royalties.

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11 Katzin, No. 08-cv-000865.
13 Williston v. Consolidated Coal Co., 637 A.2d 979, 982 (Pa. 1994) (“A lease is in the nature of a contract and is controlled by principles of contract law. It is to be construed in accordance with the terms of the agreement as manifestly expressed.”).
14 Kilmer, 990 A.2d at 1147.
One of the first significant post-Kilmer class action royalty challenges was in *Pollock v. Energy Corporation of America*,¹⁵ which is pending in the Western District of Pennsylvania. Plaintiffs, lessors with wells behind a single processing plant and sales meter, claimed they had been underpaid royalties in four ways: (1) lessee did not pay royalties on gas that was lost or otherwise unaccounted for between the well and point of sale; (2) lessee did not pay royalties on gas used before the point of sale; (3) lessee deducted post-production costs not expressly permitted by the leases and allocated post-production costs on a pro rata basis instead of calculating actual costs; and (4) lessee calculated royalties on sales price instead of price paid. On motions to dismiss and for summary judgment, the court narrowed plaintiffs’ claims.¹⁶ Importantly, the court rejected plaintiffs’ claim on allocation and found that ECA was permitted to allocate post-production costs on a pro rata basis and was not required to calculate the actual costs on a well-by-well basis. This was an issue of first impression in Pennsylvania and the court followed the customs and practice of the industry, which had been presented to the court via expert testimony.

Last year, the *Pollock* court also ruled on class certification. In September 2013, the Magistrate issued a Supplemental Report and Recommendation that recommended that two sub-classes be certified but one sub-class not be certified. The court, adopting the Magistrate’s Report, certified classes of lessors who alleged that post-production cost deductions were improperly taken related to transportation and marketing costs involving an affiliate. Currently the parties are engaging in class discovery on the marketing and transportation affiliate issues.

In another putative class action in the Court of Common Pleas of Allegheny County, *Lawrence v. Atlas Resources*,¹⁷ the Pennsylvania trial court was presented with a number of similar issues as those in *Pollock*. The court ruled on cross motions for summary judgment in December 2012 and held that, where the leases were silent on the issue of allocation, Atlas was permitted to allocate post-production costs rather than calculate the

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¹⁶ *Id*.
costs per well. Despite reaching this conclusion, and unlike *Pollock*, the court stated it was not bound by industry custom. Instead, the Court ruled that they could use “community standards of fairness and policy” to interpret the leases and pro-rata allocation of post-production costs met the expectations of the parties.

The court also rejected plaintiffs’ claim that Atlas breached the leases because an affiliate paid transportation and compression costs which were then deducted from the royalties paid. However, the court held that Atlas did breach the leases because the leases only expressly included deductions for transportation and compression and Atlas deducted other post-production costs, as well. This narrow interpretation of *Kilmer* is at odds with other recently royalty decisions such as *Katzin v. Chesapeake Appalachia, L.L.C.*,18 a 2012 Superior Court decision. The parties in *Lawrence* are currently engaged in discovery because, following the court’s Order on Summary Judgment, plaintiffs moved for class certification and the court certified the class of individuals who were royalty owners at some time after June 21, 2006. The law regarding post-production costs in Pennsylvania is still evolving, and it is unclear if the narrow interpretation in *Lawrence* or the broad interpretation of *Kilmer* in *Katzin* will carry more weight.

In a case also currently before the Court of Common Pleas of Allegheny County, the plaintiffs put that issue squarely before the court and seek to narrow existing Pennsylvania law on permissibility of post-production cost deductions. More specifically, the plaintiffs in *Hall v. CNX Gas Company*19 ask the court to reverse its opinion on allocation in *Lawrence* and hold that an oil and gas lessee is required to calculate the costs per well rather than allocate post-production costs. In both *Hall* and *Lawrence*, the leases are silent on the issue of allocation, rather than calculation, of post-production costs and deductions of those costs. Plaintiffs’ arguments mirror those in *Pollock*, as they claimed that deductions of lost and used gas based on allocation of post-production costs, rather than calculated costs, breached the leases. Plaintiffs filed their Motion for Summary Judgment on May 7, 2014, arguing that absent any express language permitting allocation, CNX must calculate the actual gas used or lost. The court has not yet issued a decision.

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More recently, a group of lessors filed a putative class action complaint in the Middle District of Pennsylvania. In *Demchak Partners Limited Partnership v. Chesapeake Appalachia*, the plaintiffs allege that they have been underpaid royalties because Chesapeake Appalachia paid their royalties based on the sale of gas in unmarketable condition at below market prices. The leases at issue have a Market Enhancement Clause which appears to prohibit the deduction of most post-production costs unless the costs result in enhancing the value of the marketable gas. At this time, there are no Pennsylvania decisions interpreting this type of clause.

Chesapeake reached a settlement with the plaintiffs and the court issued an order certifying the settlement class. However, similar market enhancement type clauses are in leases throughout the region, and lessors pursuing similar claims moved to intervene, asking the court to reject the settlement and arguing that Chesapeake is required to arbitrate all of the claims. Chesapeake moved for an injunction enjoining the class arbitration on the basis that the same claims were subject to a pending settlement. That motion is still pending with the court. The lessors-intervenors then moved to consolidate their class arbitration with the *Demchak* action. That motion is also still pending with the court.


Although the majority of the class action royalty challenges are in Pennsylvania state and federal courts, there are similar class action challenges pending in federal court in Ohio and Virginia.

[a] — Recent Royalty Litigation Trends in Ohio.

At this time, the law regarding calculation of royalty payments under an oil and gas lease and the deduction of post-production costs has not been well developed in Ohio. Ohio law has not yet definitely adopted either the netback method or marketable product doctrine for royalty calculation. However, Ohio, like Pennsylvania, treats oil and gas leases as contracts that are interpreted by the principles of contract law. Accordingly, the terms

of any royalty provision in an oil and gas lease will be significant in any royalty dispute.\textsuperscript{21} There is an unpublished decision from 1994 where the court, based on the terms of the contract, found there was no indication that transportation or other post-production costs were permissible, as it was not expressly stated in the lease agreements.\textsuperscript{22} The court recognized that other states had previously held that “no market exists for the natural gas at the point where it is removed from the well; that the lessee provides a valuable service in transporting that gas to a market and thereby increasing its value and price to the benefit of the lessor; and that the lessee should be entitled to charge a fee for rendering that service.”\textsuperscript{23} The court declined to adopt or reject the netback method, finding instead that the issues before the court could be decided without broader discussion of royalty calculation law.

Although the Ohio Revised Code contains various provisions relating to royalties paid under oil and gas leases, there have been no recent court opinions clarifying royalty calculation law or the permissibility of post-production costs and the state legislature has not weighed in.\textsuperscript{24}

However, in a putative class action pending in the Northern District of Ohio, \textit{Lutz v. Chesapeake Appalachia},\textsuperscript{25} the plaintiffs claim that they were underpaid royalties beginning in 1993. In 2010, the District Court dismissed the plaintiffs’ complaint as barred by the applicable four-year statute of limitations because certain claims accrued in 1993 and the remaining

\begin{enumerate}
\item Harris v. Ohio Oil Co., 48 N.E. 502, 506 (Ohio 1897) (“The rights and remedies of the parties to an oil and gas lease must be determined by the terms of the written instrument, and the law applicable to one form of lease may not be, and generally is not, applicable to another and different form. Such leases are contracts, and the terms of the contract with the law applicable to such terms must govern the rights and remedies of the parties.”); Morrison v. Petro Evaluation Servs., Inc., 2005 Ohio 5649 (Ohio App. 5th Dist. 2005).
\item \textit{Id.} at *5.
\item Ohio Revised Code §1509.30 requires upon request of the recipient of the royalty that the lessee timely report volumes of gas produced and the price per thousand cubic feet that the producer received. Section 1509.04 states that the Chief of the Division of Oil and Gas of Ohio Department of Natural Resources is to enforce Section 1509.30, and Section 1509.99 indicates a possible penalty of between $100 to $1,000 per day for failure to comply with Section 1509.30.
\end{enumerate}
claims accrued in 2000. In May 2013, the Sixth Circuit Court of Appeals reversed and remanded, holding that the leases are divisible contracts so the four-year statute of limitations accrues from each monthly royalty payment. The Sixth Circuit also remanded the issue of whether plaintiffs were permitted to go back further than four years under the doctrine of fraudulent concealment, because plaintiffs claim that the original lessee fraudulently concealed allegedly improper deductions and royalty calculations. The Court of Appeals instructed the District Court to analyze whether plaintiffs could prove fraudulent concealment and that they did not discover alleged underpayments despite their due diligence. In addition to the fraudulent concealment and due diligence issues before the District Court, the plaintiffs’ other claims are still pending. Specifically, plaintiffs claim they were not paid royalties on gas lost between the wellhead and point of sale and that royalties were calculated based on long term sales contracts instead of current market values. The parties spent the past year conducting class discovery and plaintiffs’ motion for class certification is due this summer.


The Virginia courts have not yet considered in a reported opinion whether the state will follow the netback method of royalty calculation and allow lessees to deduct post-production costs from royalty payments, or whether it will adopt the stricter marketable product doctrine. However, according to an opinion issued by the Virginia Attorney General, the Virginia Gas and Oil Board may issue compulsory pooling orders that authorize the lessee to pay unleased owners a one-eighth royalty based on net proceeds. The opinion found that the royalty calculation is typically made on the basis of the sales price received for the gas less the cost of marketing, transportation, and treatment.26 The opinion further stated that the lack of actual sales at the wellhead or in the field is irrelevant. The Virginia Attorney General’s opinion is based, in part on the custom and practice of the natural gas industry, and strongly indicates that the commonwealth’s preference is to follow the netback method. But, because the courts have not considered the issue, and the Virginia legislature has not weighed in, it is unclear how much precedential value the Attorney General’s opinion will ultimately have.

Issues of royalty calculation and allegedly underpaid royalties were recently raised before the Western District of Virginia. In *Adair v. EQT Production Company*,27 which is five consolidated cases, the court certified classes in each of the cases. With claims similar to those in *Pollock* and *Demchak*, plaintiffs allege that EQT and CNX miscalculated and underpaid royalties by deducting certain post-production costs or by calculating royalties based on actual sales volumes. Whether Virginia will adopt the majority rule and follow the netback method of royalty calculation would be an issue of first impression in the Virginia courts. However, the court has not reached that issue and it is unclear if the court will hear, or rule, on that issue. Instead, the central class-related dispute in *Adair* is whether royalties were improperly withheld in escrow based on the ownership of the coalbed methane. EQT and CNX have placed certain royalties in escrow because there may be an ownership dispute regarding the coalbed methane and who is owed payments for production of coalbed methane – the owner of the coal estate or the owner of the natural gas estate. Plaintiffs’ position is that this issue is settled law under an earlier Virginia Supreme Court decision. Accordingly, plaintiffs seek a full accounting and a declaratory judgment, on behalf of the class of all unleased owners of gas estates in coalbed methane pooled units.

This past fall, the court adopted the Magistrate’s Report and Recommendations and granted plaintiffs’ motion for class certification, certifying a class of any person or successor-in-interest identified by EQT as the “unleased owner of gas and lessor of gas estate interests in a tract included in a force-pooled coalbed methane gas (“CBM”) unit operated by EQT in Buchanan, Dickensen, Lee, Russell, Scott, and/or Wise County, Virginia, and whose ownership of the coalbed methane gas attributable to that tract has been further identified by EQT as being in conflict with a person or persons identified by EQT as owning coal estate interests.” Further, in addition to the declaratory judgment plaintiffs seek, they also allege assorted tort claims, including conversion, trespass, and negligence. In April 2014, EQT moved for summary judgment based on the statute of limitations, arguing that any claims for alleged underpayments accrue – and are thus now time

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barred—regardless of if the ownership of the gas still needs to be determined. EQT also separately moved for summary judgment on all remaining tort claims on the basis that plaintiffs are trying to re-cast breach of contract claims into tort claims. The motions are pending before the court.

[c] — Recent Royalty Litigation Trends in Kentucky.

In recent years, as development has increased in the Appalachian Basin region, Kentucky state and federal courts have been presented with a number of royalty disputes. Historically, Kentucky law has held that, absent language to the contrary, there is a presumption that the wellhead is the point of sale and delivery, which is where the royalty should be calculated.28 This historical precedent was examined by the United States Court of Appeals for the Sixth Circuit, applying Kentucky law, in 2011. In Poplar Creek Development Co. v. Chesapeake Appalachia, L.L.C., plaintiffs in the putative class action attempted to distinguish the earlier cases, in part based on the fact that gas used to be sold more literally at the well site, which is no longer the case.29 The court rejected plaintiffs’ various arguments, instead explaining that gathering, compression, and treatment costs cannot be distinguished from the costs of transportation. Plaintiffs had claimed that, under earlier Kentucky law, transportation is the only permissible post-production cost deduction but the court disagreed, and explained that gathering and compression are “clearly necessary to transport gas” and so the earlier precedent suggests that transportation costs were not to be viewed narrowly. Importantly, the Sixth Circuit held that Kentucky follows the “at the well” rule for calculating royalties.

Several years later, the Kentucky Supreme Court confirmed. In Baker v. Magnum Hunter Production,30 an opinion similar to the Pennsylvania Supreme Court’s in Kilmer, plaintiffs asked the court to apply the marketable product doctrine, which would prohibit the majority of post-production cost deductions from royalty payments. The appellate court affirmed the decision below, rejecting plaintiffs’ argument and applying the “at the well”

rule, permitting post-production cost deductions. The court stated that the costs of gathering, compression and treatment could be considered “transportation and processing costs” and could be deducted before lessee determined market value of the gas and apportioned the royalties. The court also expressly found that the phrase “market price at the well for gas” is unambiguous. Although a Motion for Discretionary Review was filed with the Kentucky Supreme Court in July 2013, the court has not heard the case.

Kentucky law on royalty calculation is considered well-settled that the state follows the netback method of calculation, allowing royalties to be calculated at the wellhead and post-production costs to be deducted. However, it is likely that the upcoming trends in royalty litigation in Kentucky will mirror what has been occurring in Pennsylvania – the scope of permissible deductions will need to be determined, as landowners potentially raise issues regarding allocation, specific types of post-production costs, and affiliate transactions.

The legal landscape for royalty calculation and royalty litigation in the Appalachian Basin region continues to evolve. There has also been state legislation aimed at clarifying royalty calculation practices. In particular, there is Pennsylvania state legislation that would affect the calculation of royalties, the permissibility of deduction of post-production costs, and the extent to which exploration and production companies must disclose royalty calculation information to lessors. While this law continues to develop in the region, it is likely that the increased industry attention on wet gas and natural gas liquids will create a corresponding emerging area of law.


In general, wet gas presents unique challenges for the industry in order to capture the value of the constituents. Unlike natural gas, which may be pipeline quality when produced, or may require some costs such as compression or treatment, the cost to separate out natural gas liquids may be substantial. Additionally, in order to separate out natural gas liquids, there must be separation facilities. Many of the already-built facilities are in the southern states and so to separate out the natural gas liquids, it must be piped over substantial distances to separation facilities, or substantial in-
vestment must be made to build facilities in the Appalachian Basin region, which involves additional costs. Another challenge is identifying and creating the regional market for natural gas liquids. Unlike natural gas, which is used throughout the region for manufacturing and heating, there are few facilities that can use the natural gas liquids in the Appalachian Basin region. This requires transportation of the liquids or further investment in manufacturing facilities, which again increases costs or, alternatively, decreases the value of the liquids when produced.

As the industry continues to invest in the development of natural gas liquids in the Appalachian Basin, it is likely that the next trend in royalty litigation will also focus on natural gas liquids. Much like the royalty litigation thus far in the Appalachian Basin, litigation with respect to natural gas liquids will likely focus on the proper allocation of the costs associated with getting these natural gas liquids to market, such as what costs should be proportionally shared by lessee and lessor, and what costs should be paid entirely by the lessee, given the higher costs associated with getting the natural gas liquids to market.


At this time, the current royalty litigation in the Appalachian Basin region has not focused on issues unique to natural gas liquids. However, case law relating to post-production costs litigation may extend to post-production cost deductions associated with extracting and transporting natural gas liquids to market. Based on case law developed in other jurisdictions, there are certain unique issues that may arise in the context of natural gas liquids. Case law across the region is consistent in holding that the language of the lease is paramount in any type of royalty dispute. Certain newer lease forms may specify how a royalty should be paid on natural gas liquids and, if so, then the language of the lease controls. However, more commonly, most leases are silent on issues related to the calculation and payment of royalties for wet gas and how courts in the Appalachian Basin region will interpret that silence is uncertain.

Even more broadly, it is uncertain whether a royalty is owed at all on natural gas liquids. Nationwide, a few courts have addressed this issue. Although certain lessees took the position that a lease that required a royalty
for “natural gas” did not include natural gas liquids, this position has been rejected in other jurisdictions. For example, a Texas appellate court ruled squarely that the term “natural gas” meant all components within the natural gas, so that a calculation of royalties based upon the natural gas after other minerals had been removed was improper.\textsuperscript{31} Where a lease calls for royalties to be paid on “natural gas constituents,” as many do, this issue will not arise. Further, the arguably better – and safer from a litigation standpoint — practice is to generally pay a royalty on anything of value from the gas.

Because a common practice in the Appalachian Basin region is to pay a royalty based upon the British thermal unit (BTU) factor of the natural gas and wet gas has a higher BTU factor due to the presence of the liquids, a higher royalty will be paid on wet gas. Courts in other jurisdictions have endorsed this practice on a net proceeds lease, provided that the first sale occurred prior to any separation of the natural gas liquids. In this scenario, both the lessee and lessor are being proportionally compensated for the additional value of the wet gas by the BTU adjustment factor. For example, in \textit{Sowell v. Natural Gas Pipeline Co.}, the Northern District of Texas affirmed the payment of a royalty based on the value of the natural gas received by the lessee at the first point of sale.\textsuperscript{32} The court rejected the lessor’s challenge that it was not compensated for natural gas liquids, because it received a higher royalty based on the increased BTU content. Similar to court decisions interpreting royalty payments for natural gas, whether the payment of royalty based upon the increase in BTU factor (prior to separation) is adequate will likely depend on where the first sale takes place, which can be a factual issue that turns on various legal and practical factors.

A significant factor in such an analysis is whether the sale is made to an affiliate downstream that is doing the separation and capturing the value of the separated liquids. Even after costs, the value of the separated liquids is higher than the fractional increase in value the lessor/lessee recovers from payment based on the BTU factor. So if an affiliate is capturing the increased value later in the process, legal challenges are more likely, particu-

larly as affiliate transactions have been contested recently in class action royalty disputes in Pennsylvania.

Another practical factor that will likely be considered in any analysis is what other companies are doing in the same area. The majority of the litigation involving payment of royalties for wet gas has developed in marketable product doctrine jurisdictions such as Oklahoma, Kansas, and Colorado. These jurisdictions require that the producer bear all costs associated with making the gas “marketable.” The relevant issues that have been presented in these jurisdictions are: (1) is there a duty to separate out natural gas liquids in order to make the gas marketable, and (2) who should bear the costs associated with separating out natural gas liquids. The jurisdictions have not reached a consensus on how a lessee should treat natural gas liquids and, instead, each of the marketable product doctrine jurisdictions has different rules as to what is required.

For example, two recent decisions from the Western District of Oklahoma issued contradictory opinions as to how to treat natural gas liquids. In *Naylor Farms, Inc. v. Anadarko*, the district court found that the lessee had an implied duty to separate out natural gas liquids and pay a royalty based upon the value of the natural gas liquids, without cost to the lessor, under certain lease forms at issue. The court ruled that as a matter of law, the sale of the raw gas to an unaffiliated third party that separated out the liquids and later sold them did not alter the lessee’s duty to calculate a royalty based upon the value of the natural gas liquids. The lessor in this case, however, did not argue that the gas was marketable at the wellhead and that the separation added value to any already-marketable product. In contrast, in *Fankhouser v. XTO Energy, Inc.*, the court ruled that it could not determine, as a matter of law, whether the separation of natural gas liquids was required in order to make the gas marketable. The court also stated it could not determine whether, if already marketable, the costs associated with separating out the natural gas liquids were reasonable, particularly given that an affiliate undertook these processes. These two opinions from the

Western District of Oklahoma illustrate the difficulty in assessing a lessee’s obligations with respect to natural gas liquids in marketable product rule jurisdictions. It is possible that even an arms-length sale to an unaffiliated third party may not displace implied duties. It is likely that many of these same issues will be litigated in the Appalachian Basin states. Although Pennsylvania and Kentucky courts have firmly rejected the marketable product doctrine, there are lease forms that contractually impose a similar sounding duty. Additionally, the law in Virginia and Ohio is unclear, and still evolving, as to the treatment of the marketable product doctrine, and West Virginia employs a stricter version of the marketable product doctrine.

§ 9.03. Conclusion.
Royalty calculation continues to be a highly contested and evolving area of law and class action litigation, as well as potential state legislation, is likely to continue. It is also likely that an upcoming trend in royalty litigation in the Appalachian Basin region will focus on wet gas and natural gas liquids. The law in this area is largely uncertain, although it is possible that courts in the region will look to already existing royalty calculation law for natural gas and recent opinions in Texas and Oklahoma.