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THE FIRST MARKETABLE PRODUCT DOCTRINE: JUST WHAT IS THE "PRODUCT"?

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***2** I. Introduction

Oil and gas leases normally do not set a fixed price--such as "the lessee will pay the lessor a royalty of $3.00 per barrel of production"--for calculating royalty payments. 1 Instead, oil and gas leases commonly tie royalty calculations to a more flexible yardstick, such as "the lessee will pay the lessor a royalty of 1/8th of the market value of the production at the well" 2 or "the lessee will pay the lessor a royalty of 1/8th of the net proceeds that the lessee receives ***3** for its production at the well." 3 The flexibility of the yardstick--market value, net proceeds, etc.-- allows the lease relationship to survive any dramatic volatility in oil and gas prices: a fixed royalty price of $3.00 per barrel, for example, may be excessive in a market where crude oil sells for $10.00 per barrel, while the same fixed price may be inadequate in a market where crude oil sells for $60.00 per barrel. 4

However, the flexibility of the yardstick may place lessors and lessees in a position of inherent conflict. 5 In particular, lessors and lessees may vehemently disagree about the proper location for applying ***4** the yardstick. 6 Because oil and gas production is more valuable at a downstream location than it is at the wellhead, 7 lessees may argue that they should be able to calculate royalty payments on the basis of the value or price of their production at the wellhead. By contrast, lessors and other royalty owners 8 may argue that lessees should calculate royalty payments on the basis of the value or price of the production at a point downstream of the wellhead. 9 Historically, lessees have enjoyed the better side of this argument. Over the years, most courts have ruled that the term "at ***5** the well" means that lessees may apply the appropriate yardstick measure--market value, net proceeds, etc.--to their production in the condition in which they produced it at the wellhead. 10

Recently, however, the tide has turned against lessees. Courts in several states, notably Colorado, Kansas, Oklahoma, and West Virginia, have adopted variations of the "first marketable product doctrine," which holds that a lessee must calculate the value or price of its production at the location where the lessee first obtains a marketable product--a location that may be far downstream of the wellhead. [11] In adopting the first marketable product doctrine, these courts have ruled that the term "at the well" does not necessarily mean that a lessee should apply the appropriate yardstick "at the well." Instead, these courts have reasoned that an implied covenant-- specifically, the implied covenant to market--may require a lessee to apply the appropriate yardstick downstream of the wellhead, notwithstanding any lease language stating that the lessee must calculate its royalty payments on the basis of the price or value of its production "at the well."

Of course, the proof of a legal doctrine lies in its application. If a doctrine produces absurd results, it cannot survive the crucible of time. [12] One of the most glaring flaws [13] in the first marketable product doctrine is the fact that the courts which forged the doctrine neglected to define the term "product." By holding that lessees may have to calculate royalties downstream of the wellhead, these courts presumably did not intend that the term "product" would mean the raw oil or gas stream at the wellhead. Yet, these courts failed to acknowledge that, after separation and processing, the production from an oil well may generate both crude oil and casinghead gas, [14] and the production from a gas well may generate ***6** both gas and condensate. [15] Consequently, these courts lacked the foresight to recognize the potential problems that the first marketable product doctrine would create in a fact situation where the lessee arguably produces a multitude of "products."

Lessors have taken advantage of this flaw in the case law. In recent litigation, lessors have argued that the first marketable product doctrine requires a lessee to apply the appropriate yardstick measure for calculating royalties at not simply the first location where the lessee acquires a marketable product, but at each separate location where the lessee markets a "product," whether that "product" is oil, gas, condensate, or something else. If adopted, this interpretation of the first marketable product doctrine would produce absurd and unjust results.

II. The Genesis of a Doctrine: The Oil and Gas Lease

The law governing oil and gas leases "did not spring sui generis from the head of Medusa." [16] Early in the history of oil and gas law, courts struggled with the unique character of oil and gas leases, which seemingly straddle the line between property and contract: they are neither residential leases nor commercial contracts for the sale of goods. Over the years, the courts developed a body of precedent explicitly acknowledging that oil and gas leases are a hybrid of both property and contract rights. [17] Under this body of precedent, an oil and gas lease grants the parties an interest in property; but at the same time, it contains express terms, and even possibly implied covenants, which contractually define the rights and obligations of the parties. With slight variations from state to state, this body of precedent has withstood the test of time, precisely because it draws an appropriate balance between the property and contractual elements of an oil and gas lease-- until now. The first marketable product doctrine challenges the very heart of the body of precedent governing oil and gas leases.

***7** A. The Lease As Property

Most states have agreed that an oil and gas lease gives the lessee not only a contractual right to explore for oil and gas, but also an interest in property. 18 However, while the various states have agreed that a lease creates a property interest, they have disagreed about the nature of the property interest. 19 Some states have concluded that a lease creates a fee simple determinable--a corporeal real property interest in which the lessee enjoys title to all of the oil, gas, and other minerals in place under the ground for as long as the lease remains in effect. 20 By contrast, other states have reasoned that a lease creates an incorporeal hereditament or profit à prendre--an incorporeal property interest in which the lessee enjoys the exclusive right to take all of the oil, gas, and other minerals that it is able to reduce to its physical possession, for as long as the lease remains in effect. 21

Essentially, the only thing that distinguishes the fee simple states from the profit à prendre states is the timing of the acquisition of title. In fee simple states, the lessee acquires title to the oil and gas immediately upon entering into the lease, while in profit à prendre states, the lessee acquires title only after reducing the oil or gas to ***8** its physical possession. 22 This disparity between the two types of states, at least in a royalty context, is largely a distinction without a difference. 23 The latest point at which the lessee acquires title, even in profit à prendre states, is nonetheless a location on the leased premises, where the lessee captures the oil and gas from the ground and reduces these minerals to its physical possession. Moreover, even in profit à prendre states, an oil and gas lease grants the lessee "an interest in land." 24 Consequently, in both fee simple states and profit à prendre states, a lessor and lessee do not share solely a contractual relationship for the performance of specified services. The lessee acquires valuable property rights when it enters into an oil and gas lease with a lessor. 25

In virtually any transaction that conveys an interest in property, the physical location of the "property" necessarily defines the locus of the relationship between the parties. Under an oil and gas lease, the physical location of the "property" is the wellhead on the leased property --the place where the lessee either reduces the oil, gas, and other minerals to its physical possession or recovers them from where they rest in place under the ground. 26 Indeed, the parties to a lease normally expect, absent express negotiations to the contrary, that they will perform their respective obligations in the vicinity ***9** of the leased property and not at some remote location. 27 Thus, until the advent of the first marketable product doctrine, the wellhead --as the physical location of the property rights that the lessee acquires under a lease--established the traditional location for calculating the value or price of the production from a lease. 28

B. The Lease As a Contract

An oil and gas lease is a contract between a lessor and lessee. 29 As with any other type of contract, every lease contains express ***10** covenants that specify, in writing, the parties' respective promises or agreements to each other. For instance, an oil and gas lease will normally contain a "granting clause," in which the lessor expressly agrees to give the lessee the right to explore for and produce oil, gas, and other minerals. 30 As consideration for the lessor's agreement in the granting clause, a lease will normally contain one or more "royalty clauses" in which the lessee expressly agrees to pay the lessor a "royalty"--a fractional share, either in kind or in money, of any production (i.e., any oil, gas, or other minerals that the lessee produces from the lease). 31 Most leases contain at least two royalty clauses: one that describes the royalty on gas production and another that describes the royalty on oil production. 32

A lease may also contain implied covenants. Generally, implied covenants are terms that courts may impose on one or more of the parties to a lease, ostensibly for the purpose of fulfilling the parties' unwritten promises or agreements to each other. 33 Courts have recognized a variety of implied covenants that may arise in the lease relationship. 34 Some of these implied covenants impose obligations on the lessor--for example, the implied covenant forbidding a lessor from interfering with the lessee's operations on the ***11** lease. 35 Most of the recognized implied covenants impose obligations solely on the lessee, such as: (a) the implied covenant to develop the leased premises; (b) the implied covenant to protect the leasehold from drainage or waste; (c) the implied covenant to manage and administer the lease; and (d) the implied covenant to market any production from the lease. 36

Many recent oil and gas royalty disputes arise from a tension between express covenants and implied covenants: the lessee may rely on the express terms of the royalty clause to argue that it properly calculated its royalty payments on the basis of the price or value of its production at the wellhead, while the lessor may rely on an implied covenant--the implied covenant to market--to argue that the lessee should have calculated its royalty payments on the basis of a downstream price or value for its production. Theoretically, the law favors express covenants over implied covenants. 37 Thus, at least in principle, a court should not use an implied covenant to alter the express terms of the agreement between the parties; 38 and to the extent that the parties have expressly defined ***12** their rights and obligations in the lease agreement, a court should not enforce an implied covenant to impose different or greater rights and obligations. 39

Reality, however, is not always consistent with theory. 40 The first marketable product doctrine represents the unfortunate triumph of implied covenants over express covenants.

1. The Royalty Clause in an Oil and Gas Lease

The terms of an oil and gas lease, like the terms of any other type of contract, are subject to negotiation. 41 "Because each lease is individually negotiated, each varies as to the lessor's and lessee's rights and duties." 42 Consequently, "[t]here is no standard royalty clause." 43 Even within the same field of production, a royalty clause in one lease may vary substantially from a royalty clause in another lease. 44 As Justice Priscilla Owen, formerly on the Supreme Court of Texas, has explained:

> [N]ot all royalty clauses were created equal. Some are based on "proceeds," some on "amount realized," while others are based on "market value." Some specify the point at which the value of the ***13** royalty is determined, such as "at the well." Some do not. Some leases have more than one method for valuing royalty depending on whether the gas is sold or used off the leased premises or is sold at the well. 45

Nonetheless, at the risk of oversimplification, most royalty clauses will generally fall into one of two broad categories: those that require the lessee to pay monetary royalties, and those that require the lessee to provide for the delivery of royalty oil or gas in kind. 46 A lessee's obligations--and indeed, a royalty owner's rights--are different under a "monetary" royalty clause than under an "in-kind" royalty clause. 47

a. Payment of Money Royalties

Many, if not most, royalty clauses require that the lessee pay monetary royalties to its royalty owners. Customarily, a "monetary" royalty clause does not set a fixed price for royalty payments; rather, it gives the lessee a flexible yardstick for calculating royalty payments. 48 For example, a royalty clause may require that the lessee pay monetary royalties on the basis of the market value or market price of its production. 49 To illustrate, the clause may read: ***14** (1) The lessee covenants to pay royalties "on gas, including casinghead gas or other gaseous substances, produced from said land and sold or used, the market value at the well of one [-]eighth (1/8) of the gas so sold or used," 50 or (2) The lessee covenants to "pay to the lessor for such one-eighth royalty, the market price for oil of like grade and gravity prevailing on the day such oil is run into the pipe line or into storage tanks." 51

Conversely, a royalty clause may require that the lessee pay monetary royalties on the basis of the gross or net proceeds or price that the lessee receives from selling its production. For example: (1) "The royalties to be paid by lessee are: . . . on gas, including casinghead gas or other gaseous substance, produced from said land and sold on or off the premises, one-eighth of the net proceeds at the well received from the sale thereof, ..." 52 or (2) The lessee covenants to "pay Lessor as a royalty for all such oil, condensate and their constituents so produced and saved an amount equal to one-eighth of the gross [or net] sales proceeds realized by ***15** Lessee from the sale of such products." 53 As a matter of simple economics, the term "market value" does not mean the same thing as the term "proceeds." 54 The "proceeds" or "price" that a lessee receives in a transaction for the sale of oil or gas may be higher (if the lessee makes a good deal) or lower (if the lessee makes a bad deal) than the "market value" or "market price" of its oil or gas. 55

Besides giving the lessee a flexible yardstick for calculating royalty payments, a monetary royalty clause may also specify a location where the lessee should apply the yardstick. Most royalty clauses, for instance, expressly require that the lessee calculate the market value or price of its production "at the well" or "at the ***16** wellhead." 56 Some royalty clauses use slightly broader terms, such as "in the field of production." By comparison, still other royalty clauses, although a small minority, specifically require that the lessee calculate the market value or price of its production at a point downstream of the wellhead. For example:

> Lessor's royalty gas shall be free of cost to Lessor and . . . sold by Lessee (for Lessor's account) to the purchaser of Lessee's gas for the same relative consideration received by Lessee at the point of delivery of such gas . . . .
>
> . . . .
>
> Except as herein otherwise expressly provided, Lessor's royalty shall not bear, either directly or indirectly, any part of the costs or expenses of production, gathering,

> dehydration, compression, transportation, manufacturing, processing, treating or marketing the "oil and/or gas" attributable to the leased premises 57

Under a monetary royalty clause, the lessee acquires title to all of the oil and gas it produces from a lease. 58 The lessor and other royalty owners never acquire title to any part of the production. Therefore, if the lessee fails to comply with the terms of a monetary royalty clause, the lessor may potentially sue the lessee for breach of the lease agreement, but the lessor may not sue the lessee for conversion. 59

***17** b. Delivery of Royalty in Kind

Some royalty clauses, particularly oil royalty clauses, contain "in-kind" royalty language. 60 Under an "in-kind" royalty clause, the lessor is entitled to receive a proportional share of the oil or gas that the lessee produces from the lease. 61 Generally, an "in-kind" royalty clause will provide that the lessee may deliver the lessor's royalty oil--the lessor's proportional share of the lessee's production--either to the lessor's physical possession or to the lessor's credit in a pipeline or other oil storage facility. 62 For example, an "in-kind" royalty clause may provide: "In consideration of the premises, the said lessee covenants . . . to deliver to the credit of the lessor, free of cost, in the pipe line to which he may connect his wells, the equal one-eighth part of the oil produced and saved from said leased premises." 63 Alternatively, for delivery to the lessor's storage facility, the royalty clause may state: Lessee covenants "[t]o deliver to the credit of Lessor, free of cost, into the pipe line to which Lessee may connect its wells, or at Lessor's option to storage by the Lessor provided the equal one-eighth (1/8) part of all oil produced and saved from said leased premises." 64

***18** Under an "in-kind" royalty clause, the lessor owns the title to its royalty oil. 65 Therefore, if the lessee fails to comply with the requirements of an "in-kind" royalty clause, the lessor may potentially bring an action against the lessee not only for breach of the lease agreement, but also for conversion of the lessor's royalty oil. 66

The lessee's duty of performance to the lessor will necessarily depend on the terms of the royalty clause. Typically, however, a lessee may satisfy its obligations under an "in-kind" royalty clause in one of three ways:

> a. If the lessor owns storage facilities, the lessee may deliver the lessor's royalty oil to the lessor's physical possession. 67
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> b. If the lessor does not own any storage facilities where it may receive physical possession of his royalty oil, the lessee may deliver the lessor's royalty oil to a third party purchaser, 68 which may then buy ***19** the oil by entering into a division order with the lessor. 69 In this context, the division order is a contract of sale that serves to transfer title from the lessor to the purchaser. 70 The division order will specify the terms under which the purchaser will pay for the lessor's royalty oil. 71 Although these terms will vary from division order to division order, they frequently require the purchaser to pay the lessor either (1) the "market value" or "market price" of the lessor's royalty oil at the well, or (2) the "proceeds" or "price" that the purchaser ***20**

paid to the lessee for the lessee's share of the production. 72 By receiving payments from the purchaser, the lessor waives its right to receive physical possession of the royalty oil. 73

c. The lessee may itself buy the oil from the lessor. As is the case with a third party purchase, the lessee may enter into a division order that specifies the terms under which the lessee will pay for the lessor's royalty oil. 74

2. The Implied Covenant to Market

The implied covenant to market has long roots in American oil and gas law. 75 Historically, the implied covenant to market has ***21** rested upon the basic premise "that the parties to the lease transaction intend for the lessee to market the production for their common benefit." 76 Most lessors and other royalty owners hope to "benefit" from the lease relationship by receiving royalties. 77 Thus, where the lessee's marketing efforts may potentially affect the amount or existence of a lessor's royalties, the implied covenant to market recognizes that the lessee must market its oil and gas production in a way that would mutually benefit both the lessee and the lessor--not merely the lessee alone. 78 In other words, the implied covenant to market serves, where necessary, to ensure that the lessee does not elevate its own interests to the point where the lessee deprives the lessor of the very "benefit" that the lessor hoped to receive by entering into a lease in the first place. 79

The basic premise that undergirds the implied marketing covenant dates back to Iams v. Carnegie Natural Gas Co., 80 an 1899 ***22** decision from the Supreme Court of Pennsylvania. 81 The plaintiffs in Iams were lessors under a lease that required the lessee to pay $500 in royalties each year that it produced and marketed gas from the lease. 82 Although the lessee produced gas from the lease, the lessee refused to pay royalties to the plaintiffs, apparently on the basis that it had not "marketed" any of the gas. 83 The trial court ruled in favor of the plaintiffs. Affirming the trial court, the supreme court held that once the lessee had produced gas in "sufficient quantities" to justify marketing the gas from the lease, the lessee could not avoid its duty to pay royalties simply by refusing to market the gas. 84 As the court in Iams noted, the lessee was "under an 'obligation to operate for the common good of both parties, and to pay the rent or royalty reserved.'" 85

In the years following Iams, the implied covenant to market never strayed far from its basic premise of protecting the common good of both the lessor and lessee. Although oil and gas leases varied widely in their terms, most leases contained a habendum clause providing that they would remain in effect through their primary term and "so long thereafter as oil or gas or other hydrocarbon substances are produced in paying quantities." 86 Under this type of clause, a lease would terminate if the lessee failed to produce oil, gas, or other minerals in paying quantities. Therefore, the implied covenant to market served, at least in some measure, to ensure that a lessee would make reasonable efforts to preserve a lease that was capable of producing in paying quantities. Following this train of thought, "neither the lessor [nor the] lessee gained any ***23** advantage from the discovery of hydrocarbons unless those substances were marketed." 87

As it developed from its infancy, the implied covenant to market eventually embraced two distinct elements--a "timing" element and a "pricing" element. 88 Under the "timing" element, the lessee owed a duty to market its production, if prudently possible, within a reasonable period of time. 89 This element of the implied covenant ensured both that the lessor would timely receive royalty income and that the lessee would not improperly hold the lease for speculative purposes; 90 for example, by refusing to market any production from the lease, and instead, paying nominal shut-in royalties to the lessor solely for the purpose of leaving open the option of allowing the lease to terminate. 91 If the lessee discovered oil or gas in paying quantities, the lessee had to act diligently to identify and pursue a market for its production. 92 The lessee could not unreasonably delay its marketing efforts if the delay would unduly postpone its payment of royalties to the lessor. 93

***24** Under the "pricing" element of the implied covenant to market, the lessee owed a duty to market its production for a reasonable price. 94 This element of the implied covenant ensured that the lessee would not unfairly enter into contract terms that would reduce the lessor's royalty payments in situations where "the amount of the royalty depend[ed] upon the price at which the product is marketed." 95 Thus, if a lease required the lessee to pay the lessor a proportional share of the "proceeds" or "price" that the lessee received for its production, 96 the lessee could not simply sell its oil or gas to any potential purchaser on any terms whatsoever. Instead, the lessee had a responsibility to sell its production for the "best price reasonably available"; in other words the best, although not necessarily the highest, price that the lessee could reasonably attain under existing market conditions. 97

Until the advent of the first marketable product doctrine, neither the "timing" element nor the "pricing" element of the implied covenant to market ever suggested that courts may rewrite the express ***25** terms of a lease agreement to require that a lessee calculate its royalty payments on the basis of the value or price of its production at a point downstream of the wellhead. 98

Viewed in its proper historical light, the implied covenant to market is not a sweeping rule of law that allows courts to rewrite the terms of lease agreements. To the contrary, the implied covenant to market is, or at least should be, a very narrow rule of law. In four key respects, the analytical foundations for the implied marketing covenant have limited its application in royalty disputes. First, at least historically, the implied covenant to market arises only when necessary to protect the common good of both the lessor and the lessee. 99 A lessee has no duty to subordinate its own interests to those of its royalty owners. 100 Consequently, "in making decisions regarding the marketing of gas, a lessee is only required to consider beneficial alternatives. The lessee is not required to pursue a change in market value or any other course of action simply because such a change would benefit its royalty owners." 101

Second, the implied covenant to market arises only after the lessee has discovered and produced a product in sufficient quantities to justify marketing the product. 102 In other words, "[c]learly one must have a product to market before a duty to market will arise." 103

***26** Third, the implied covenant to market arises only where necessary to fulfill the parties' legitimate contractual expectations. The implied covenant to market is "implied in fact," not "implied in law." 104 Unlike an implied-in-law covenant that would exist in every contract as a matter of law, an implied-in-fact covenant is simply a "gap filler"--it fills a contractual gap in those leases where the parties have reached a meeting of the minds, but have failed to specify all of the terms of their agreement in writing. 105 Ultimately, "[i]t is the product of agreement, although it is not expressed in words." 106 As the Supreme Court of Texas has explained:

> [W]hen parties reduce their agreements to writing, the written instrument is presumed to embody their entire contract, and the court should not read into the instrument additional provisions unless this be necessary in order to effectuate the intention of the parties as disclosed by the contract as a whole. An implied covenant must rest entirely on the presumed intention of the parties as gathered from the terms as actually expressed in the written instrument itself, and it must appear that it was so clearly within the contemplation of the parties that they deemed it unnecessary to express it, and therefore omitted to do so, or it must appear that it is necessary to infer such a covenant in order to effectuate the full purpose of the contract as a whole as gathered from the written instrument. It is not enough to say that an implied covenant is necessary in order to make the contract ***27** fair, or that without such a covenant it would be improvident or unwise, or that the contract would operate unjustly. It must arise from the presumed intention of the parties as gathered from the instrument as a whole. 107

Accordingly, as an implied-in-fact covenant, the implied covenant to market exists only to fulfill, not contradict, the intent of the parties to a lease agreement. 108 The implied covenant to market, at least in its historical form, does not permit courts to rewrite a lease agreement contrary to the parties' intent, even if a contrary interpretation of the lease would arguably produce a "fairer" or more "equitable" agreement. 109

Fourth, the implied covenant to market, even in those instances where it applies, does not impose an unreasonably strict standard of care. It merely requires that lessees satisfy the standard of a reasonably prudent operator. 110 Consistent with the basic premise of the implied covenant, this standard of care demands only that a lessee pursue those marketing efforts which, under the circumstances, "would be reasonably expected of operators of ordinary ***28** prudence, having regard to the interests of both lessor and lessee." 111 This standard is a "standard of prudence, not of prescience." 112 In effect, a lessee often must make difficult marketing choices. 113 However, as long as the respective interests of the lessor and lessee are not in direct conflict, courts have traditionally declined to use the "reasonably prudent operator" standard as a pretext for second-guessing a lessee's marketing decisions. 114

***29** Regrettably, the first marketable product doctrine ignores these historical limitations on the implied marketing covenant. Under the first marketable product doctrine, the implied covenant to market may allow courts to second-guess a lessee's marketing decisions. It may apply "in law" to every lease, potentially requiring the lessee to subordinate its own interests to those of its lessors. And perhaps most disturbingly, the doctrine may allow lessors to argue that the lessee must produce--and pay royalties on--products that do not exist in paying quantities at the wellhead.

III. The Evolution of a Doctrine: From Consistency to Chaos

Prior to the first marketable product doctrine, the law governing the calculation of royalty payments was fairly uniform. Because a royalty was, by definition, a share of the "production" under a lease, courts agreed that the lessee was solely responsible for bearing all of the costs necessary to achieve "production." 115 The meaning of the term "production" was uncontroversial; in the royalty context, "production" referred simply to the oil, gas, and other minerals that the lessee extracted from the ground at the wellhead, where the lessee reduced the minerals to its physical possession. 116 Thus, under case law requiring that the lessee bear all of the costs of "production," the lessee had a duty to pay, by itself and without charge to its lessors, all of the exploration, drilling, and operational ***30** costs necessary to extract any oil, gas, or other minerals from the ground and bring them to the surface of the leased premises. 117

While agreeing that the lessee was solely responsible for paying all production costs, courts also recognized that the lessee, as a general rule, was entitled to pay royalties on the basis of the value or price of its production at the wellhead, not at any location downstream of the wellhead. 118 This rule was consistent with most royalty clauses, which usually contained language specifying that the lessee should calculate its royalty payments "at the well" or "at the wellhead." 119 But even in the absence of such language, this rule was also consistent with the definition of a "royalty"--a share of the "production," which the lessee achieved at the point where it extracted oil, gas, or other minerals from the ground. 120 Consequently, even when a lease did not contain "at the wellhead" or similar language, courts routinely held that as long as the lease did ***31** not expressly require otherwise, the lessee could properly pay royalties on the value or price of its production at the wellhead. 121

The general rule establishing that a lessee could properly calculate its royalty payments at the wellhead was "a well recognized, basic concept of oil and gas law for many decades." 122 On the basis of this general rule, courts developed a set of basic principles to guide lessees in calculating their royalty payments. For example, under a market value at the well royalty clause, 123 courts concluded that a lessee could calculate its royalty payments by using one of the two following methods: 124

> (a) the comparable sales method--a method in which the lessee determined the market value of its oil or gas production at the wellhead by averaging the prices that the lessee and other producers are ***32** receiving, at the same time and in the same field, for oil or gas of comparable quality, quantity, and availability; 125 or
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> (b) the workback or netback method--a method in which the lessee determined the market value of its oil or gas production at the wellhead by taking the sales price that it received for its oil or gas production at a downstream point of sale and then subtracting the reasonable post-production costs (including transportation, gathering, compression, processing, treating, and marketing costs) that the lessee incurred after extracting the oil or gas from the ground. 126

***33** Of these two methods for calculating market value, courts preferred the comparable sales method over the workback method, 127 principally because the workback method tended to overestimate the value of production at the wellhead. 128 Nonetheless, in those frequent instances where evidence of comparable sales was either nonexistent or unavailable, courts commonly allowed lessees to use the workback method as an alternative to the comparable sales method. 129

Under a net proceeds at the well or an amount realized at the well royalty clause, courts concluded that the lessee had to calculate its ***34** royalty payments on the basis of the actual price of its production, as measured at the wellhead. 130 If the lessee sold its oil or gas production to a third party purchaser at the wellhead, the lessee had to pay its lessors their proportional royalty-share of the actual price that the lessee received for its production. 131 Conversely, if the lessee sold its production at a location downstream of the wellhead, the lessee could calculate its royalties under a workback method--taking the price that it received on the sale of its oil or gas production and then deducting reasonable post-production costs to determine the net proceeds that the lessee realized for its production at the well. 132

***35** Most states still adhere to these basic principles for calculating royalties. 133 Generally, courts in these states continue to treat a market value royalty clause differently from a proceeds royalty clause. 134 In particular, these courts hold that the price a lessee receives under a fixed oil and gas contract does not automatically establish the market value of the product under a market value royalty clause. 135 As already established, the one type of royalty calculation that a lessee may use under both a market value or proceeds royalty clause is the workback method-- but only for the purpose of "working backward" to estimate the value or price of the lessee's production at the wellhead, in the absence of any better evidence of this value or price. In these states, the workback method remains a valid means of calculating the value or price of the lessee's production at the wellhead, when the lessee neither sells its production there nor has evidence of comparable sales from the same field. 136

***36** Unfortunately, courts frequently use imprecise language to describe the workback method, suggesting either (a) that a lessee may "deduct" post-production costs from its monetary royalty payments, 137 or (b) that a lessor must "share" post-production costs with the lessee. 138 Contrary to the inherent implication of this language, the workback method does not allow a lessee arbitrarily to "charge" costs to its lessors or otherwise "reduce" the royalties that it owes to its lessors. 139 As such, the workback method is simply an appraisal technique. 140 It is not a cost-shifting rule, and it does not apply when the lessee does not need to estimate the value of its production at the wellhead by reference to its value at a downstream location. For instance, if a lessee sells its production to a third party purchaser at the wellhead, under a proceeds royalty ***37** clause the lessee may not "deduct" any post-production costs from its royalty payments; instead, it must pay its lessors their fractional royalty share of the sales price at the wellhead. 141

Nonetheless, the imprecise language suggesting that lessees may "deduct" post-production costs from their monetary royalty payments inadvertently planted the seeds that ultimately produced the first marketable product doctrine. Royalty owners chafed at the implication that a lessee could "charge" them with a share of the costs that the lessee incurred after removing the minerals from the leased premises. 142 The earliest sprouts of what later became the first marketable product doctrine appeared in cases where lessors and other royalty owners merely sought to challenge the "deductibility" of certain types of costs. 143 From these cases, the first marketable product doctrine grew into a tangled mess of weeds challenging, on a variety of different analytical grounds, the basic principles of royalty calculation, essentially under the guise of protecting royalty owners from unfair "deductions" in their royalty payments. 144

And therein lies the problem. Although the first marketable product doctrine, by its name, appears to carry the force of an established "doctrine," it is not so much a "doctrine" as it is the ambiguous product of a widely varying and internally inconsistent set of commentaries and opinions. Consequently, with the rise of the first marketable product doctrine, oil and gas royalty law has moved from consistency to chaos.

A. The Commentators

The courts that have adopted the first marketable product doctrine have cited the writings of three professors at the University of ***38** Oklahoma School of Law: Maurice H. Merrill, Eugene O. Kuntz, and Owen L. Anderson. 145 While these three professors shared a common law school, they did not speak with a united voice. On the contrary, they reached three entirely different conclusions, during three entirely different time periods.

1. Professor Maurice Merrill

In 1926, Professor Maurice Merrill published the first edition of a treatise entitled The Law Relating to Covenants Implied in Oil and Gas Leases. 146 In his treatise, Merrill argued that the oil and gas lease was an inherently unfair bargain in which the lessee inevitably took advantage of its lessors. 147 On the basis of this argument, Merrill suggested that courts depart from the normal rules of contract construction to create a new body of implied covenants designed specifically for the purpose of protecting lessors and other royalty owners. Specifically, Merrill stated:

> May there not be, in the conditions peculiar to the oil and gas industry and to the leases executed for the purposes of that industry, circumstances affecting the relation of "lessor" and "lessee" which justify the somewhat radical departures from ordinary rules which have characterized the decisions upon the implication of covenants?
> . . . .
> . . . Since the lease is prepared by the lessee or from the point of view of his interests, since the lessor does not ordinarily know what provisions are necessary for enforcing the operations the promise of which is held out to him by the lease, and since the utter impossibility of foreseeing all of the conditions which may surround the lease in the future cuts off all chance of phrasing express provisions to meet the demands of these conditions, the lessor's opportunity to protect himself by exact stipulation is illusory. 148

Having expressed the doubt that lessors could protect themselves in lease negotiations, Merrill argued that courts should apply ***39** his new body of implied covenants "in law" to every oil and gas lease, regardless of the express terms of the lease or the intent of the parties. "Of course, the implied covenant is a fiction, used like other fictions by the law in order to achieve a desirable result. . . . The obligations are imposed, not by the agreement of the parties, but by operation of law." 149

In a second edition of his treatise published in 1940, Professor Merrill further expanded his view of the law of implied covenants. Claiming that marketing expenses were not "deductible" costs, Merrill suggested that the implied covenant to market precluded a lessee from using the workback method to calculate royalties at the wellhead. According to Merrill:

> If it is the lessee's obligation to market the product, it seems necessarily to follow that his is the task also to prepare it for market, if it is unmerchantable in its natural form. No part of the costs of marketing or of preparation for sale is chargeable to the lessor. 150

Although Merrill had previously noted that his vision of implied covenants was a radical departure from existing law, Merrill asserted in the second edition of his treatise that his interpretation of the implied covenant to market was "supported by the general current ***40** of authority." 151 He was wrong. The general current of authority did not support his interpretation of the implied covenant to market; rather, the case law at the time of Merrill's treatise uniformly recognized that a lessee could properly deduct marketing costs and other expenses in applying a workback calculation to determine the value or price of its production at the wellhead. 152

In the years immediately following Professor Merrill's treatise, few courts heeded Merrill's interpretation of the implied covenant to market, probably because Merrill's interpretation was indeed a radical departure from the royalty law existing at the time of Merrill's treatise. Only decades later would Professor Merrill's interpretation reemerge, like a phoenix from the ashes, as a key component in some courts' interpretations of the first marketable product doctrine. 153 As two oil and gas practitioners wryly observed: "Merrill's analysis was not embraced by courts when it was reasonably fresh, but lay ignored waiting to be 'discovered' over fifty years later. Unfortunately the courts that discovered Merrill's dormant analysis took no note that it had been ignored by so many for so long." 154

2. Professor Eugene Kuntz

In 1962, Professor Eugene Kuntz published a comprehensive review of oil and gas law, which he appropriately entitled A Treatise ***41** on the Law of Oil and Gas. 155 In his treatise, Professor Kuntz argued that a lessee should not be able to "charge" its lessors with any costs that the lessee incurred before it acquired a "marketable" product. Specifically, he urged:

> [T]here is a distinction between acts which constitute production and acts which constitute processing or refining of the substance extracted by production. Unquestionably, under most leases, the lessee must bear all costs of production. . . . It is submitted that the acts which constitute production have not ceased until a marketable product has been obtained . . . .

It is not always easy to determine, however, when the first marketable product has been obtained. Marketability of the product may be affected because the quality of the raw gas is impaired by the presence of impurities. In this instance, it should be necessary to determine if there is a commercial market for the raw gas. If there is a commercial market, then a marketable product has been produced and further processing to improve the product should be treated as refining to increase the value of the marketable product. If there is no commercial market for the raw gas, the lessee's responsibilities theoretically have not ended, and the lessee should bear the costs of making the gas marketable. 156

Kuntz cited no authorities for his proposition that production ceases only when the lessee acquires a marketable product, 157 and in fact, Kuntz conceded that the case law was "not all consistent with this analysis." 158

Like Professor Merrill, Professor Kuntz concluded that a lessee could not necessarily deduct all of its downstream costs in determining the value or price of its production for royalty purposes. Kuntz's analysis, however, differed entirely from Merrill's analysis. Instead of relying--as Merrill did--on the implied marketing covenant, 159 Kuntz relied solely on his interpretation of the rules of ***42** contract construction. Under Kuntz's analysis, the "deductibility" of costs is purely a function of the meaning of the term "production" in the royalty clause of a lease. Kuntz defined the term "production" to require a "marketable product." 160 Because a lessee normally bears sole responsibility for all costs of "production," Kuntz argued that a lessee must itself pay, without charge to its lessors, all of the costs necessary to produce a "marketable product"--a product for which, according to Kuntz, the lessee actually has a "commercial market." 161

Not only did Kuntz's analysis differ from Merrill's analysis, it also produced a different result. While Merrill had concluded that a lessee could charge "no part" of its marketing costs to its lessors, 162 Kuntz concluded that a lessee could potentially charge some or all of its costs, including marketing costs, to its lessors--but only after the lessee had acquired a marketable product. As Kuntz explained: "After a marketable product has been obtained, then further costs in improving or transporting such product should be shared by the lessor and lessee if royalty gas is delivered in kind, or such costs should be taken into account in determining market value if royalty is paid in money." 163 Thus, in contrast to Merrill, Kuntz recognized that a lessee could properly use a workback method to calculate its royalty payments as long as the lessee only "worked back" to the point where it first acquired a marketable product and not all the way back to the wellhead.

In the years immediately following Kuntz's treatise, courts in oil and gas producing states gave no more credence to Kuntz's analysis ***43** than they had previously given to Merrill's analysis. 164 Kuntz's analysis, as with Merrill's analysis, would lie largely unnoticed until the 1990s, when a small handful of courts rediscovered Kuntz's analysis and used it as a cornerstone for their versions of the first marketable product doctrine. 165

3. Professor Owen Anderson

In 1997, Professor Owen Anderson published a series of law review articles in which he argued that a lessee does not fulfill its duty to obtain "production" until the lessee has first acquired a marketable product. 166 Unlike Merrill and Kuntz, Anderson wrote his articles in the 1990s, at a time when courts in some states--particularly Oklahoma, Kansas, and Colorado--had already adopted the first marketable product doctrine. 167 Recognizing, however, that these courts had adopted inconsistent versions of the doctrine, 168 Anderson offered what he believed to be a definitive version of the doctrine, or as he described it, "a guiding principle for construing typical royalty provisions," which he hoped would result in "greater uniformity among the various jurisdictions, [and] more consistent interpretation of various (but essentially equivalent) royalty clauses." 169

***44** Professor Anderson argued that many courts in royalty cases had improperly pursued a "property-law" analysis, which in his view unduly emphasized that the lessee took physical possession of the minerals at the wellhead. 170 According to Anderson, a "property-law" analysis offends the likely intent of the parties, who would reasonably expect the lessee to secure--and pay royalties on--a marketable product. 171 In lieu of a "property-law" analysis, Anderson advocated a "contract-law" analysis that, in his opinion, would construe royalty clauses in a manner more consistent with the likely intent of the parties. Thus, under his contract-law analysis:

> Oil and gas lease royalty clauses should be construed as a whole . . . .

When the typical royalty clause is considered as a whole in light of what the parties may have mutually and reasonably intended, the clause contemplates actual commercial sales of a product in a real ***45** marketplace regardless of whether that sale occurs at the well or off the premises. Both "amount realized" and "market value" contemplate real and willing buyers buying a real product from real and willing sellers in a real market. . . . And a real sale cannot occur without a real sales contract. 172

Anderson observed that under every oil and gas lease, the lessee must solely bear all of the costs necessary to achieve "production." 173 Echoing Kuntz's analysis, Anderson asserted that the term "production" in the royalty clause of a lease invariably implies the existence of a "marketable product, a ready and willing seller, and a ready and willing buyer." 174 Thus, Anderson concluded that a lessee achieves "production" only "at the point where a first-marketable product has in fact been obtained, which is not necessarily at the point of extraction." 175

While advocating a "contract-law" analysis, Professor Anderson rejected the idea that courts should try to enforce the literal meaning ***46** of each term in a royalty clause. 176 Instead, Anderson urged courts to construe a royalty clause "in its entirety and against the party who offered it." 177 On the basis of this broad (and conveniently unfettered) rule of construction, Anderson suggested that most royalty clauses--whether using "market value," "net proceeds," or other royalty yardsticks--would embrace the first marketable product doctrine. In that regard, Anderson wrote:

> I submit that many of the modern gas royalty clauses encountered in printed lease forms offered by prospective lessees are best viewed as expressing practically identical obligations even though the words used may vary. . . . These clauses should be viewed as having a similar objective: to remit to the lessor the major consideration for having executed what becomes a productive oil and gas lease. In the absence of express language to the contrary, that consideration should be a share in the value of gas as a first-marketable product. 178

Anderson implicitly disagreed with Professor Merrill's view that the first marketable product doctrine derives from the implied marketing covenant. Accordingly, Anderson stated: "There is no need to resort to the implied covenant to market to reach this conclusion. Courts need only consider the object of the lease in light of its purpose: the production of hydrocarbons that generate income to the lessee and a cost-free royalty share to the lessor." 179

Professor Anderson denied that the terms "at the well" or "at the wellhead" were inconsistent with his interpretation of the typical***47** royalty clause. Interestingly, while Anderson advocated a "contract-law" analysis that would purportedly enforce the intent of the parties, 180 he agreed that the original intent behind the terms "at the well" and "at the wellhead" was to ensure that a lessee could calculate its royalty payments on the basis of the price or value of its oil or gas at the wellhead. As such, Anderson wrote:

> As the gas royalty clause evolved, there is little doubt about what lessees intended when they drafted many of the various gas royalty clauses commonly encountered over the last [fifty] plus years. Lessees gradually refined the gas royalty clause because they wanted to have the right to charge the lessor, through royalty accounting, for a proportionate share of any post-wellhead costs incurred prior to sale.

To accomplish their objective, most lessees did not choose to directly state that the lessor could be charged, through royalty accounting, for a proportionate share of post-wellhead costs. Rather, most lessees settled on the phrase "at the well," "at the wellhead," or "at the mouth of the well" in lieu of the more traditional "free of cost, in the pipeline" phrase or in lieu of silence. 181

Yet, while never actually claiming that the terms "at the well" or "at the wellhead" were ambiguous, Anderson argued that courts should not reward a lessee for using either of those terms. Essentially, Anderson alleged that the lessee, as the party that customarily drafts the lease, could and should use more explicit terms if it intends to calculate its royalties on the basis of the price or value of its production in the form at which it emerges from the wellhead. 182

Even so, Professor Anderson agreed that the terms "at the well" and "at the wellhead" were not entirely meaningless. 183 Suggesting that these terms were akin to F.O.B. shipping terms in a commercial contract, 184 Anderson argued that the terms referred simply to ***48** the physical location for calculating royalties, not to the physical condition of the oil or gas at the time that they emerge from the ground at the wellhead. 185 Anderson concluded:

> ***49** Under this approach, the added phrase "at the well" would permit the lessee to deduct a proportionate share of "freight," i.e., transportation. Accordingly, the lessee would pay royalty on the value of gas when it first becomes marketable, less the reasonable actual cost of transporting the gas to the actual marketing point beyond the vicinity of the well. The point at which gas first becomes a marketable product would be established on the basis of a known and real market. 186

In this respect, Anderson's analysis differed from Professor Kuntz's analysis, which would have required the lessee to bear all of the post-wellhead costs necessary to secure a marketable product, including apparently the transportation costs to move oil and gas from the wellhead to a commercial market. 187

Professor Anderson claimed that his version of the first marketable product doctrine did not radically revise royalty law in favor of lessors, but rather walked the "fence somewhere between the views of royalty owners and the views of oil and gas operators." 188 In a limited sense, Anderson's analysis was correct. Anderson concluded that a lessee should calculate its royalty payments at the point where it first acquires a "marketable product"--which may or may not be at the wellhead--and that the lessee owes no duty to pay royalties on any further value or profit that the lessee obtains downstream of the point where it first acquires a "marketable product." 189 Additionally, in calculating royalties from a downstream ***50** sales price, Anderson acknowledged that a lessee may: (1) deduct transportation costs back to the wellhead; 190 and (2) deduct processing, marketing, and other post-production costs back to the point where the lessee first acquires a "marketable product." 191

Nonetheless, Professor Anderson's analysis, like the analyses of Professors Merrill and Kuntz, did not find widespread acceptance. Four years after proposing his version of the first marketable product doctrine, Anderson lamented that his analysis had been "largely ignored or misinterpreted." 192

***51** B. The Case Law

Notwithstanding the rise of the first marketable product doctrine, most states continue to adhere to the general rule that a lessee may calculate its royalty payments according to the value or price of its oil and gas at the wellhead, rather than at a location downstream of the wellhead. 193 Only in four states--Kansas, Oklahoma, Colorado, and West Virginia--have courts explicitly rejected this general rule in favor of the first marketable product doctrine. 194 Nevertheless, despite their common recognition of it, the ***53** first marketable product doctrine does not even mean the same thing in each of these four states. Just as Professors Merrill, Kuntz, and Anderson each offered different versions of the doctrine, the courts in these four states have created still further permutations of the doctrine. Significantly, these permutations are not only inconsistent from state to state, but also inconsistent with the opinions of Professors Merrill, Kuntz, and Anderson.

1. Kansas

Early Kansas cases, in line with the case law in most other states, permitted a lessee to use the workback method as a formula for calculating royalty payments. 195 As the Supreme Court of Kansas explained in its 1958 Matzen v. Hugoton Production Co. 196 decision:

> [W]here, as here, the gas produced is transported by the lessee in its gathering system off the premises and processed and sold, its royalty obligation is determined by deducting from gross proceeds reasonable expenses relating directly to the costs and charges of gathering, processing and marketing the gas. Thus, proceeds from the sale of gas, wherever and however ultimately sold, is the measure of plaintiffs' royalty,

> less reasonable expenses incurred in its gathering, transporting, processing and marketing. 197

Although Kansas courts recognized that the implied marketing covenant required a lessee to market its production, they concluded--at least early in their jurisprudence--that the implied covenant ***54** did not alter the general rule that "the lessor is entitled only to his oil or gas or the value thereof at the well and not at some distant market." 198

The tide shifted in 1964, when the Supreme Court of Kansas handed down opinions in two royalty cases involving largely identical facts, Schupbach v. Continental Oil Co. 199 and Gilmore v. Superior Oil Co. 200 In each case, the parties had entered into leases that required the lessee to pay royalties in the amount of "1/8 of the proceeds of the sale [of gas] at the mouth of the well." 201 The lessee in each case sold its gas production to a company that operated a pipeline across the leased premises. 202 In calculating the royalty payments, both lessees deducted from their gross proceeds all costs incurred to compress the gas for delivery into the pipeline. 203 In both cases, the supreme court ruled that the lessee improperly deducted these compression costs. 204 Citing Professor Merrill's treatise, the Gilmore court concluded that the implied covenant to ***55** market required the lessee to bear all of the compression costs "necessary to make the gas marketable." 205

Initially, Gilmore and Schupbach produced more of a ripple than a wave. Many believed at the time that the opinions affected only the types of costs-- specifically, compression costs incurred on the leased premises--that a lessee could deduct under a workback method for calculating royalties. 206 Indeed, three years after Gilmore and Schupbach, a Kansas federal court in Ashland Oil & Refining Co. v. Staats, Inc., 207 concluded that the implied covenant to market did not require a lessee to bear all of the gathering or compression costs necessary to deliver its gas production to a distant commercial market. 208 The federal court in Ashland Oil held that Gilmore and Schupbach stood only for the limited proposition that a lessee could not deduct "costs for compressing casinghead gas which lacked sufficient pressure to enter the purchaser's line on the premises." 209

***56** Only three decades later did it become clear that the decisions in Gilmore and Schupbach were actually the first waves in the tide that would develop into the first marketable product doctrine. 210 In a 1995 decision, Sternberger v. Marathon Oil Co., 211 the Supreme Court of Kansas attempted to reconcile its previous royalty decisions by distinguishing between transportation costs and the costs of making a product "marketable." 212 The court concluded that Matzen and other early Kansas cases merely allowed a lessee to share transportation costs with its lessors. According to the court's analysis:

> These cases clearly show that where royalties are based on market price "at the well," or where the lessor receives his or her share of the oil or gas "at the well," the lessor must bear a proportionate share of the expenses in transporting the gas or oil to a distant market.
>
> . . . .
>
> [Matzen and other early cases] all stand for the proposition that reasonable transportation expenses are shared by the lessor and the lessee where royalties are paid (in oil or gas or in money) "at the well" but there is no market at the well. 213

By comparison, the court determined that Gilmore and Schupbach required the lessee to bear all of the remaining expenses--other than transportation costs-- necessary to produce a first marketable product. 214 Thus, despite the language in Matzen stating that lessors should bear a proportionate share of the gathering, processing, and marketing costs, the court in Sternberger interpreted Gilmore and Schupbach to have adopted the first ***57** marketable product doctrine as a function of the implied covenant to market. 215

Although the supreme court in Sternberger confirmed that the first marketable product doctrine was the law of Kansas, the court--perhaps surprisingly to the plaintiffs--concluded that the lessee in that case had correctly used a workback method to calculate its royalty payments to its lessors. 216 The lessee, in conducting its workback calculation, deducted only the costs incurred to build a pipeline from the wellhead to a commercial market. 217 Significantly, the court observed that oil and gas may be marketable at the wellhead even in the absence of a commercial market. The court commented:

> Once a marketable product is obtained, reasonable costs incurred to transport or enhance the value of the marketable gas may be charged against nonworking interest owners. . . . In the case before us, the gas is marketable at the well. The problem is there is no market at the well, and in that instance we hold the lessor must bear a proportionate share of the reasonable cost of transporting the marketable gas to its point of sale. 218

Finding that the pipeline costs were transportation costs rather than marketing costs, the Sternberger court ruled that the plaintiffs were "responsible for their proportionate share of the reasonable expenses in transporting the gas from [the] wellhead to market." 219 Because the court determined that a product--the gas--was marketable ***58** at the well, the court had no need to define the term "product."

Six years after Sternberger, the Supreme Court of Kansas added yet another wrinkle to its royalty jurisprudence with its decision in Smith v. Amoco Production Co. 220 The plaintiffs in Smith were lessors who brought a class action against their lessee for alleged breaches of the implied covenant to market. 221 In turn, the lessee alleged that the statute of limitations barred the lessors from pursuing their claims. 222 The Smith court concluded that the applicable statute of limitations was the five year statute for actions on written contracts, not the three year statute for oral contracts. 223 Without citing Sternberger or even acknowledging the first marketable product doctrine, Smith noted that the implied covenant to market was "implied in fact" and arose from the written terms of an oil and gas lease. 224 The court emphasized that the lessor bears the burden of proving each of the elements necessary to establish a breach of the implied covenant to market. 225

In sum, since Gilmore and Schupbach, the Kansas Supreme Court has recognized a version of the first marketable product doctrine that reflects elements of both Professor Merrill's analysis (e.g., the reliance on the implied covenant to market) and Professor Anderson's analysis (e.g., the deduction of reasonable transportation costs). As it has evolved, however, Kansas's version of the doctrine is not entirely consistent with either professor's analysis. In contrast to Professor Anderson's analysis, Kansas holds not only that the first marketable product doctrine arises from the implied covenant to market, but also that oil and gas may be marketable "at the well" even in the absence of a commercial market at the ***59** wellhead. 226 Additionally, in contrast to Professor Merrill's analysis, Kansas holds that the implied covenant to market is implied in fact, not in law. 227 While Kansas may be the first state to have embraced the doctrine, Kansas's version of the first marketable product doctrine is distinctive.

2. Oklahoma

As in Kansas, early cases in Oklahoma permitted a lessee to use the workback method as a formula for calculating royalty payments. 228 For example, in the 1940 decision of Cimarron Utilities Co. v. Safranko, 229 the Supreme Court of Oklahoma observed: "The rule for ascertaining market value, . . . when no prevailing market price is shown to exist, . . . holds that market value is synonymous with actual value, and may be proved by showing the selling price less the expense of marketing the commodity." 230 While Safranko acknowledged that the workback method was not an exclusive formula for calculating royalty payments, it reasoned--consistent with the prevailing rule in other states--that the workback method was an appropriate formula to determine the value of oil or gas production at the wellhead, in the absence of comparable wellhead sales. 231 Not surprisingly, many lessees in Oklahoma "relied ***60** upon this seemingly clear precedent in structuring their leases." 232

The Supreme Court of Oklahoma muddied the waters, however, in its 1992 decision in Wood v. TXO Production Corp. 233 Responding to a certified question from federal court, the state supreme court purported to answer whether a lessee was "entitled to deduct" compression costs from its royalty payments. 234 Despite language in the Safranko opinion stating that a lessee may calculate royalties by deducting marketing costs from the downstream sales price of its gas production, the Wood court interpreted Oklahoma precedent to hold "only that the lessor must bear its proportionate share of transportation costs where the point of sale was off the leased premises." 235 Implicitly overruling Safranko, the supreme court held that "the implied duty to market means a duty to get the product to the place of sale in marketable form." 236 Finding that compression costs were necessary to prepare gas production for market, 237 the court ruled that a lessee could only deduct transportation ***61** costs, not compression costs, from its royalty payments to its lessors. 238

Two years after concluding that a lessee could not deduct compression costs from its royalty payments, the Supreme Court of Oklahoma addressed whether a lessee could deduct dehydration and gathering costs. In TXO Production Corp. v. State ex rel. Commissioners of the Land Office, 239 the state land office complained that the lessee had improperly calculated its royalty payments by using a workback method that deducted compression, dehydration, and gathering costs to determine the market value of its production at the wellhead. 240 Noting that Wood forbade a lessee from deducting compression costs, the supreme court in TXO extended its decision in Wood and held that "[i]f the processes of dehydration and gathering are necessary to prepare the product for market, then the costs of these processes may not be deducted under the royalty provision of the subject lease." 241 The court then concluded, ***62** essentially as a matter of law, that dehydration and gathering are necessary to prepare gas production for a commercial market. 242

The decisions in Wood and TXO engendered a storm of criticism. 243 Arguably, in response to this criticism, the supreme court in a 1998 decision, Mittelstaedt v. Santa Fe Minerals, Inc., 244 retreated from the language in TXO suggesting that a lessee may never deduct dehydration or gathering costs. 245 While reemphasizing that the implied covenant to market requires a lessee to bear all of the costs necessary to derive a marketable product from otherwise unmarketable oil or gas production, 246 the Mittelstaedt court ***63** concluded that the lessor may have to pay a proportionate share of those post-production costs, including dehydration and gathering costs, when the lessee can prove the following three facts: "(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." 247

Essentially, Mittelstaedt held that the lessee, and not the plaintiff-lessor, bears the burden of proof on a claim that the lessee improperly used a workback method to calculate its royalty payments. 248 ***64** Thus, under Mittelstaedt a lessee may deduct post-production costs from its royalty accounting methodology only if it can satisfy the burden of proving, as an affirmative defense, that its post-production activities did not actually create a marketable product, but rather enhanced an already marketable product. 249 In light of this affirmative defense, the supreme court noted that "in some cases a royalty interest may be burdened with post-production costs, and in other cases it may not." 250 Significantly, however, the court did not attempt to define either the term "marketable" or the term "product." 251

Mittelstaedt may have tempered the effect of Wood and TXO, but it created yet another distinctive version of the first marketable product doctrine. In Oklahoma, as in Kansas, the first marketable product doctrine arises from the implied covenant to market. 252 However, unlike in Kansas where the lessor bears the burden of ***65** proving that the lessee breached the implied covenant to market, 253 Oklahoma effectively places the burden on the lessee--in the nature of an affirmative defense--to disprove a lessor's claim that the lessee breached the implied covenant to market by deducting post-production costs from its royalty payments. 254 The ways in which these two states allocate the burden of proof have produced different results; by comparison with the Kansas courts, Oklahoma courts have demonstrated less willingness to uphold a lessee's reliance on the workback method for calculating royalties. 255

3. Colorado

In contrast with Kansas and Oklahoma, Colorado does not have an extensive body of royalty case law. The first major Colorado case to discuss royalty accounting issues was a 1994 decision, Garman ***66** v. Conoco, Inc. 256 In Garman, the Supreme Court of Colorado responded to a certified question from a federal district court asking whether a lessee could require overriding royalty interest owners to bear a proportionate share of the post-production costs. 257 The supreme court summarily answered the question in the negative, but declined to address the specific terms of the leases or assignments at issue in the case. 258 Although Garman cited Professor Kuntz (and not Professor Merrill) in support of its decision, 259 the court relied on the implied marketing covenant--which it characterized as a covenant implied in every oil and gas lease 260--to conclude that the first marketable product doctrine was the law in Colorado. The court stated:

> ***67** Conoco argues that the implied covenant to market exists separately from the allocation of marketing costs. We disagree. . . . In our view the implied covenant to market obligates the lessee to incur those post-production costs necessary to place gas in a condition acceptable for market. Overriding royalty interest owners are not obligated to share in these costs. 261

The Garman court ruled that a lessee could only "charge" nonworking interest owners with those costs that it incurred to enhance the value of marketable oil or gas--those costs that the lessee incurred after it obtained a first marketable product. 262

The Supreme Court of Colorado revisited the first marketable product doctrine seven years later in Rogers v. Westerman Farm Co. 263 The plaintiffs in Rogers were royalty owners under leases which provided that their lessees would pay royalties on the price or value of their production "at the well" or "at the mouth of the well." 264 The defendant-lessees argued that the terms "at the well" and "at the mouth of the well" allowed them to calculate their royalty payments to the plaintiffs by using a workback method to deduct their post-production costs--including their transportation costs, if not also their processing, treating, and other downstream costs--from the downstream sales price of their oil and gas production. ***68** 265 The court disagreed and held that these terms were not "sufficiently clear to set forth the proper allocation between the parties of the costs of gathering, compressing, and dehydrating the gas." 266

Arguing that the bargaining power between a lessee and lessor is similar to that between an insurer and insured, 267 the Rogers court concluded that it must "strictly construe" the language of the leases in favor of the lessor. 268 Curiously, the court did not find that the terms "at the well" or "at the mouth of the well" were ambiguous. To the contrary, it conceded that a majority of states had ruled that the term "at the well" unambiguously defined the point at which a lessee may calculate the price or value of its production for royalty purposes. 269 Nonetheless, on the basis of its "strict" rule of lease construction, the court rejected the majority approach and held that the terms "at the well" and "at the mouth of the well" were "silent with respect to allocation of costs." 270 The supreme court ***69** did not identify any alternate definition for these terms; for all practical purposes, it simply deleted these terms from the leases at issue in the case. 271

Having determined that the terms "at the well" and "at the mouth of the well" were silent with respect to the allocation of costs, Rogers reemphasized that the first marketable product doctrine was the law in Colorado. 272 The court, however, could not resist the opportunity to place yet another unique spin on the doctrine--indeed, expressly acknowledging that it did not adopt Professor Anderson's version of the doctrine. 273 In particular, the court rejected Professor Anderson's view that the first marketable ***70** product doctrine arises from the express terms of the royalty clause. Instead, the court determined that the first marketable product doctrine necessarily arises out of the implied covenant to market. In that regard, the court stated:

> Although Anderson argues that there is no need to resort to the implied covenant to market in adopting the first-marketable product rule, we disagree. Instead, we conclude that under circumstances such as those presented here where there are no

> express provisions contemplating allocation of costs with respect to royalty calculations, the implied covenant to market is implicated. 274

The court suggested that every oil and gas lease, as a matter of law, imposes on the lessee an implied covenant to market. 275 Consequently, "[u]nder the implied covenant to market, the lessees have a duty to make the gas marketable. . . . Costs incurred to make the gas marketable are to be borne solely by the lessee[ ]." 276

Moreover, the court ruled that the first marketable product doctrine requires the lessee to bear all of the transportation costs--as well as the marketing costs and other downstream expenses--to the location where the lessee acquires a first marketable product. In the court's words:

> ***71** [W]e have concluded that the "at the well" lease language in this case is silent as to allocation of all costs, including transportation costs. Under these circumstances, the logic of the first-marketable product rule requires that the allocation of all costs be determined based on when the gas is marketable. Thus, we decline to single out transportation costs and treat them differently than other costs.
> . . . .
> Once gas is deemed marketable based on a factual determination, the allocation of all costs can properly be determined. Absent express lease provisions addressing allocation of costs, the lessee's duty to market requires that the lessee bear the expenses incurred in obtaining a marketable product. Thus, the expense of getting the product to a marketable condition and location are borne by the lessee. 277

To explain its reasoning, the court attempted to define the term "marketability" --but not the term "product." According to the court's definition, "marketability" demands not only that the lessee conduct those operations necessary to place its oil or gas production in a marketable condition, but also that the lessee transport its production to a marketable location. By the court's own analysis:

> In defining whether gas is marketable, there are two factors to consider, condition and location. First, we must look to whether the gas is in a marketable condition, that is, in the physical condition where it is acceptable to be bought and sold in a commercial marketplace. Second, we must look to location, that is, the commercial marketplace, to determine whether the gas is commercially saleable in the oil and gas marketplace. 278

The court observed that "the determination of marketability is a question of fact," reasoning that a jury or other factfinder should decide the point at which the "first marketable product" is in both a "marketable condition" and a "marketable location." 279

***72** Significantly, the supreme court in Rogers rejected the notion that a lessee could prove that its oil or gas production was marketable simply by identifying a potential purchaser for its production at the wellhead. 280 Despite holding that marketability is a fact question and not a matter of law, the court effectively decreed --as a matter of law --that a "marketable location" could only be a location that involves a "commercial exchange, in a viable market, [in other words], a commercial marketplace." 281 Thus, by adding a "marketable-location" component to the first marketable product doctrine, Rogers deviated dramatically from other first marketable product cases, such as Wood--which recognized that lessors must bear a proportionate share of the costs of transporting the oil or gas production to a downstream market 282--and Sternberger--which recognized that oil or gas production may be marketable at the wellhead even in the absence of a commercial market. 283

Rogers's version of the first marketable product doctrine does not mean, as is the case in Kansas and Oklahoma, that the lessee must bear the costs of acquiring a first marketable product from otherwise unmarketable oil or gas production. Under Rogers, the ***73** first marketable product doctrine means that the lessee must take its production, whether the production is in a marketable condition at the wellhead or not, and get it to a commercial market. Then, the lessee must pay royalties to the lessor on the basis of the enhanced value of the first marketable product that the lessee acquires from its production at the commercial market, without taking any deductions for the costs that contributed to the enhanced value of that product. In short, Rogers pushes the royalty valuation point downstream of the wellhead in all cases except those involving leases that specifically authorize the lessee to calculate royalties on the basis of the value or price at the wellhead (and, even then, only if the leases use language more explicit than merely "the lessee must pay royalties on the basis of the market value of the gas at the well").

By adding a "marketable-location" requirement to the definition of "marketability," Rogers represents an extreme--and results-oriented--version of the first marketable product doctrine. 284 Notably, Professor Anderson, who is a prominent advocate of the doctrine, has criticized the "marketable-location" rule in Rogers by arguing that it improperly requires "lessees to bear costs that they have not historically borne." 285 Although Professor Anderson has ***74** lamented the fact that no courts have adopted his version of the first marketable product doctrine, 286 he has complained that Rogers goes further astray from his version of the doctrine than any other first marketable product case--and not just a little bit astray, but indeed, "on an odyssey to a new and distant galaxy." 287 As Anderson has observed, "no oil and gas scholars, not even Professor Merrill, the 'Godfather' of oil and gas implied covenants, support the court's marketable-location rule." 288

The defect in the Rogers decision, however, is not simply the definition of "marketability." By defining only the term "marketability" and not the term "product," Rogers arguably leaves open several fundamental questions: (1) What "product" is sufficient to satisfy the duty of securing a "first marketable product" ?; (2) May a lessee calculate its royalty payments at the point where it first achieves a marketable product (e.g., the point where it can first sell condensate), even if not all of the components of the production stream (e.g., gas, carbon dioxide, or entrained natural gas liquids) are marketable at that point?; and (3) Despite its identification as the "first" marketable product doctrine, does the doctrine require that the lessee achieve "marketability," including both a "marketable condition" and a "marketable location," for each of the components in the production stream that it produces from its wells?

4. West Virginia

The latest state to adopt a common law version of the first marketable product doctrine is West Virginia. In Wellman v. Energy Resources, Inc., 289 the plaintiffs received royalties under leases providing that the lessee would pay "one-eighth (1/8) of the proceeds from the sale of gas as such at the mouth of the well." 290 The plaintiffs complained that the lessee did not pay royalties on the actual ***75** price--or proceeds--that the lessee received for its gas. In response, the lessee argued that it properly deducted its expenses from the price it received for its gas. 291 On appeal, the Supreme Court of West Virginia arguably could have resolved the case by observing that the lessee offered no evidence showing that it sold its gas downstream of the wellhead. 292 Such a ruling would have been relatively uncontroversial; even in states that have declined to adopt the first marketable product doctrine, a lessee under a proceeds lease may not use the workback method to calculate royalties on oil or gas that the lessee sells to a third party purchaser at the wellhead. 293

Instead, the supreme court took a different tack. While analyzing the leases at issue, the court largely ignored the term "at the mouth of the well" 294 and focused exclusively on the term "proceeds." ***76** The court summarily concluded that a "proceeds" royalty clause requires a lessee to pay royalties "on the basis of what the lessee receives from the sale of oil and gas." 295 Despite the precedent holding that a "net proceeds at the well" royalty clause allows a lessee to use the workback method to calculate royalties, 296 the court suggested that major oil and gas producers had concocted the workback method--and had actually dreamed up the term "post-production expenses"--as a means of defrauding lessors out of their "share" of the ultimate downstream sales price for oil and gas production. The court stated:

> [T]here has been an attempt on the part of oil and gas producers in recent years to charge the landowner with a pro rata share of various expenses connected with the operation of an oil and gas lease such as the expense of transporting oil and gas to a point of sale, and the expense of treating or altering the oil and gas so as to put it in a marketable condition. To escape the rule that the lessee must pay ***77** the costs of discovery and production, these expenses have been referred to as "post-production expenses." 297

Interestingly, while focused on the term "proceeds," the court acknowledged that "different issues" may arise under a "market value" royalty clause as opposed to a "proceeds" royalty clause. 298

The Wellman court purported to align West Virginia with other first marketable product states. 299 However, the court never actually used the term "first marketable product." Nor did the court recognize the variations in the first marketable product doctrine from state to state. Indeed, the court conducted only a cursory review of the case law from other first marketable product states. 300 As the following excerpt illustrates, the court incorrectly assumed that these states applied the doctrine uniformly:

> ***78** This [c]ourt believes that the rationale employed by Colorado, Kansas, and Oklahoma in resolving the question of whether the lessor or the lessee should bear "post-production" costs is persuasive. Like those states, West Virginia holds that a lessee impliedly covenants that he will market oil or gas produced. Like the courts of Colorado, Kansas, and Oklahoma, the [c]ourt also believes that historically the lessee has had to bear the cost of complying with his covenants under the lease. It,

therefore, reasonably should follow that the lessee should bear the costs associated with marketing products produced under a lease. 301

In particular, Wellman concluded--akin to the Colorado case law in Rogers but in contrast to the case law in Kansas and Oklahoma 302--that a lessee must bear all of the transportation costs necessary to deliver its production to a commercial market. 303

Arguably, Wellman took the first marketable product doctrine even a step beyond Rogers. 304 While the Colorado, Kansas, and Oklahoma courts had each ruled that a lessee must bear most, if not all, of the costs that the lessee incurs up to the point where it first acquires a marketable product, 305 the Wellman court ruled: ***79** "[I]f an oil and gas lease provides for a royalty based on proceeds received by the lessee, 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." 306 The court essentially held that even if a lessee acquires a marketable product at the wellhead or at an intermediate location short of the actual point of sale, the lessee may nonetheless have to pay its lessors a proportionate share of the actual price that the lessee receives for its production at the point of sale without taking into account any enhanced value the lessee may have added to the production through its transportation, compression, treating, processing, gathering, dehydration, or marketing efforts. 307 Thus, whether intentionally (as a result of its apparent antagonism against oil and gas producers) or unintentionally (as a result of its cursory review of the case law), the Supreme Court of West Virginia adopted yet another version of the first marketable product doctrine--a version perhaps more accurately named the "first point of sale doctrine" than the "first marketable product doctrine." 308

5. Summary of the First Marketable Product States

The first marketable product doctrine has thrown oil and gas royalty law into chaos. Four different states have emerged with four different versions of the first marketable product doctrine:

• In Kansas, the implied covenant to market provides that the lessee must bear all expenses, other than transportation costs, necessary to produce a first marketable product. However, in an action for breach of the implied covenant to market, the lessor has the burden of proving the point at which the lessee acquires a marketable ***80** product. To fulfill this burden, the lessor must do more than simply prove the absence of a market at the wellhead.

• In Oklahoma, the implied covenant to market provides that the lessee must bear all expenses, other than transportation costs, necessary to produce a first marketable product. Nonetheless, in an action for breach of the implied covenant to market, the lessee may argue, as an affirmative defense (on which the lessee has the burden of proof), that its post-production activities did not actually create a marketable product but rather enhanced an already marketable product.

• In Colorado, the implied covenant to market requires the lessee to bear all expenses, including transportation costs, necessary to produce a first marketable product--a product that is both (a) in a marketable condition, and (b) at a marketable location. As a matter of law, the location must be a sales point downstream of the wellhead if there is no commercial market at the wellhead.

• In West Virginia, the implied covenant to market, at least under a "proceeds" lease, provides that the lessee must bear all expenses it incurs at any location from the wellhead to the point of sale, including transportation costs.

The inconsistency in these versions of the first marketable product doctrine has fostered the belief--perhaps the reality--that the doctrine lacks any cornerstone principles and effectively means whatever a good advocate may persuade a court to find.

The courts in the first marketable product states have not yet attempted to define the term "product." Lessors, with the assistance of some very able advocates, have attacked this gap in the case law to suggest that the first marketable product doctrine requires lessees to produce a marketable product from each component in the stream of production--and to bear all of the costs of doing so. Good advocacy, however, does not necessarily make for good law. If the first marketable product doctrine means anything at all (and, for a variety of reasons, it should not be the law in any oil and gas producing state), it should mean only that the lessee has the duty to produce a "first" marketable product, not that the lessee has the burden of producing a marketable product from each component in the stream of production.

***81** IV. At a Crossroads: The Flaws in the First Marketable Product Doctrine

Now that at least four states have adopted common law versions of the doctrine, the first marketable product doctrine may have become a permanent addition to the oil and gas lexicon. That result is unfortunate. As two oil and gas practitioners in Mississippi have observed, the first marketable product doctrine, "though perhaps well-intentioned, is a mistake that should die the same way it was conceived." 309 These two Mississippi practitioners are not alone in recognizing that the doctrine is a mistake. Many other commentators, including scholars who generally are sympathetic to royalty owners, have criticized the various permutations of the first marketable product doctrine, identifying a variety of flaws in these permutations--both patent and latent. 310 While some permutations of the doctrine suffer from greater problems than others, the flaws that these commentators have identified in the doctrine may be generally summarized as follows:

First, the doctrine has clouded oil and gas royalty jurisprudence. The first marketable product doctrine "stands in sharp contradiction ***82** to longstanding judicial precedent." 311 Although oil and gas royalty law once recognized that a lessee may calculate its royalty payments at the wellhead, the first marketable product doctrine has uprooted established jurisprudence and divided oil and gas states into two categories: those states that have adopted the doctrine, and those continuing to follow the jurisprudence that predates the doctrine. 312 Even in those states that have adopted it, the doctrine lacks consistent rules to ensure uniform application from state-to-state and lessee-to-lessee. The net effect of the doctrine is uncertainty, both to lessees in calculating their royalty payments and to the courts in resolving royalty disputes. 313 An individual who seeks to predict a court's potential application of the doctrine to a particular set of facts may have as much luck trying to tack jello to a wall. As Professor Anderson admitted:

> Unfortunately, given the mix of views encountered in the various states concerning royalty valuation standards, we may have arrived at the worst possible result, which is that royalty valuation must be determined on a state-by-state, interest-by-interest, and clause-by-clause basis. . . . [T]hese various approaches will fuel litigation in states whose courts have not considered the various royalty valuation issues. The result will be large bodies of case law that offer little guidance to parties facing a royalty valuation dispute. The end result will serve only to make domestic exploration and production even less competitive in the world marketplace. 314

***83** The uncertainty that the doctrine brings to oil and gas royalty jurisprudence creates the illusion, if not the reality, that royalty calculation has no cardinal principles of law--certainly none that a creative advocate could not subsequently either sidestep or submit to methodological challenge in a courtroom. 315

Second, the doctrine fails to acknowledge that an oil and gas lease gives the lessee property rights as well as contractual rights. Anderson complained that many courts had favored a "property-law" analysis over a "contract-law" analysis. 316 Contrary to the implication in Anderson's argument, no court has ever used pure property law principles to resolve a royalty dispute. Even in those states that have rejected the first marketable product doctrine, courts have uniformly held that oil and gas leases are contracts--subject to the normal canons of contract construction. 317 But, as these courts have recognized, a proper construction of a lease acknowledges that it gives the lessee both contractual rights and an interest ***84** in property. 318 Ultimately, unless a lessor receives "in-kind" royalties from the lessee, 319 the lessor owns no title to any oil or gas that the lessee produces from a lease. 320 Thus, as with any other contract involving an interest in property, a lease will normally contemplate that the lessee must "pay" for the property (i.e., the production) on the basis of the price or value of the property at the location where the lessee acquires title (i.e., the leased premises). 321

Third, even to the extent that the doctrine purports to arise from a contract-law analysis, the doctrine does not correctly apply the rules of contract construction. For instance, the Colorado Supreme Court, in Rogers, held that it must "strictly construe" an oil and gas lease, allegedly because the bargaining power between a lessee and lessor is similar to that between an insurer and insured. 322 The bargaining power between a lessee and lessor, however, is not akin to that between an insurer and insured. As Professor Anderson observed in his criticism of Rogers:

> [T]he most common insurance contracts are true contracts of adhesion offered to most customers on a take it or leave it basis.

Lessors, unlike typical insurance customers, do have significant bargaining power--though many lessors may not realize this fact. Indeed, so-called "landowner oil and gas lease" forms are now fairly common. 323

***85** Even if a lease were subject to the same rule of strict construction as an insurance contract, a court may not--as the Rogers court apparently did-- summarily adopt the interpretation that favors the lessor, no matter how unreasonable another interpretation would be. In insurance cases, a court may not "strictly construe" an insurance contract unless it first determines that the contract is ambiguous and requires "construction" 324--a step that the supreme court ignored in Rogers. 325

Fourth, the doctrine fails to give effect to the plain terms of a standard royalty clause. In any case involving a contract, a court must try to give effect to the expressed intent of the parties before turning to any canons of contract construction. 326 Specifically, if the terms of a contract are plain and unambiguous, a court must enforce the contract as written. 327 The canons of contract construction "***86** are merely tools designed to assist a court in ascertaining the intent of the part[ies] rather than rules of law that may be used to defeat that intent . . . . Canons should never prevail over the language used in the instrument." 328 Yet, in at least two key respects, the first marketable product doctrine invokes canons of contract construction--such as the strict construction rule in Rogers--to rewrite lease terms that courts have long found to be plain and unambiguous. 329 To illustrate:

•"At the well" means a location "at the well," not a downstream marketing location. Historically, the words "at the well" establish the point where the lessee should calculate the value or price of its production. 330 However, in interpreting the term "market value at ***87** the well," the first marketable product doctrine argues that the proper location for calculating the value of oil and gas production is a commercial market, not the wellhead. Consequently, the doctrine--at least as described in Rogers and Wellman -- purports to give effect to the word "market" at the expense of the words "at the well." 331 This interpretation, which Rogers justified on the basis ***88** of a "strict construction," defies the rule that courts should try to ascertain the parties' intent by giving effect to all of the words in their contract. 332 Moreover, it produces a result that defies the parties' expectations. Taking an example from outside the oil and gas context, if a buyer were to purchase raw diamonds at their "market value in the ground," the parties would reasonably expect that the buyer must pay the seller a purchase price equal to the value of the diamonds at the point of extraction, not the price that the buyer receives after polishing and cutting the diamonds for a commercial market. 333

•"Production" means "the act of producing oil, gas, and other minerals," not the act of transporting, gathering, treating, processing, or marketing oil or gas. Historically, "production" ceases once the lessee extracts oil or gas from the ground at the wellhead. 334 The ***89** historical definition of "production" is consistent with the common understanding of the term; to "produce" is to make or create a product that did not previously exist, and not to refine or improve a product already in existence. 335 The first marketable product doctrine, however, argues that the act of "production" does not end until the lessee obtains a first marketable product--a product that the lessee may have had to refine or improve for market. 336 As the Colorado Supreme Court in Rogers observed, this interpretation means that "depending on the factual scenario, 'production' could end at the point of extraction,

> or elsewhere." 337 Thus, the first marketable product doctrine takes a word that formerly had a clear meaning and twists it into something that may, as Professor ***90** Anderson admits, "vary from area-to-area and perhaps [even] from well-to-well." 338

Fifth, the doctrine incorrectly assumes that "market value" requires the actual existence of a "market." One of the key assumptions underlying the first marketable product doctrine is the idea that the terms "market value" or "market price" presuppose the existence of "real and willing buyers buying a real product from real and willing sellers in a real market." 339 This assumption, however, is simply incorrect. The term "market value" does not require the presence of actual buyers or a real market. 340 Many ***91** products, such as raw materials or used goods, may lack a readily available market until after the owner does "something" to them--for example, refurbishes them, refines them, or transports them to a bulk sales center. The fact that the owner must do "something" to a product to attract potential buyers does not mean that the product lacks a "market value" in its original or unimproved state. 341 Indeed, as the Kansas Supreme Court recognized in Sternberger, oil and gas production may be marketable at the wellhead even in the absence of a market at the well. 342

Sixth, the doctrine misapplies the implied covenant to market. The decisions in Sternberger, Mittelstaedt, Rogers, and Wellman argue that the first marketable product doctrine arises from the implied covenant to market. 343 However, as Professors Kuntz and Anderson have acknowledged, the implied covenant to market is not a valid analytical foundation for the doctrine. 344 Prior to the first marketable product doctrine, the implied covenant to market was irrelevant to the question of whether a lessee could use a workback method to calculate royalties. As such:

> The implied covenant to market only requires that a lessee make reasonable efforts to obtain the best price possible. The covenant says nothing about the obligation of a lessee to employ a particular ***92** mechanism to calculate royalty, and it certainly does not require that the lessee employ a mechanism that contradicts the terms of the lease. 345

By seeking to shove a round peg down a square hole, the case law adopting the first marketable product doctrine has radically altered the very nature of the implied covenant to market. The implied covenant should conform to the following:

> •The implied covenant to market should not arise where the parties to a lease have expressly defined their rights and obligations. Under established contract-law principles, a court may not use an implied covenant to reach a result different from that which the parties contemplated in the express terms of their agreement. 346 Where a lease contains "market value at the well" or "net proceeds at the well" royalty terms, the parties have expressly defined their rights and obligations: the lessee must pay, and the lessor must receive, royalties on the basis of the market value (for a market value lease) or price (for a proceeds lease) of the lessee's production "at the well," not at a location downstream of the wellhead. 347 By dictating that a lessee may have to pay royalties on the basis of the ***93** price of its production at a downstream commercial market, the first marketable product doctrine

potentially allows the implied marketing covenant to trump the express terms of an oil and gas lease and gives lessors "the benefit of a bargain they never made." 348

•The implied covenant to market should be implied only in fact, not in law. Most states have concluded that the implied covenant to market is implied in fact--in other words, implied only as necessary to enforce the parties' intent where they did not otherwise state their intent expressly. 349 However, by concluding that the first marketable product doctrine arises from the implied covenant to market, those states that have adopted the doctrine have struggled to rationalize it with the traditional implied-in-fact character of the covenant. 350 Colorado, for instance, has simply rejected an implied-in-fact approach in favor of an implied-in-law approach and consequently concluded that the implied covenant to market applies to all oil and gas leases, regardless of the parties' intent. 351 By contrast, Kansas has expressly declared that the implied covenant to market is implied in fact; 352 but at the same time, it has suggested--more in line with an implied-in-law approach--that the first marketable product doctrine potentially applies in all cases ***94** where the lessor can prove that the lessee's oil or gas production is not marketable at the wellhead. 353

Seventh, the doctrine is unfair to lessors who receive royalties in kind. Historically, the purpose of the implied covenant to market was to protect the lessor where the amount and existence of the lessor's royalties depended upon a condition over which the lessor had no control--the lessee's marketing efforts. 354 In that sense, the implied covenant to market sought to place the lessor in the same position that it would have occupied if it had received royalty oil or gas in kind at the wellhead and marketed the oil or gas on its own. 355 The first marketable product doctrine, however, places a lessor who receives money royalties in a better position than a lessor who receives royalties in kind. While the first marketable product doctrine demands that a lessor need not bear the costs necessary to produce a first marketable product, a lessor who takes possession of royalty oil or gas under an in-kind royalty clause must make its own marketing decisions--with all of the attendant business risks--and bear all of the costs necessary to deliver the oil or gas to a commercial market and place the production in a marketable condition. 356

***95** Eighth, the doctrine potentially gives lessors an undeserved windfall. A royalty interest entitles a lessor to receive a share of the lessee's production, not a share of the lessee's profits. 357 This rule intuitively makes sense. A lessor participates in oil and gas activities only to the extent required to give its lessee the right to explore for and produce oil or gas on the leased premises. 358 If the lessee transports its production off of the lease, the lessee typically assumes all of the downstream risks. 359 For instance, if a lessee decides to process any wet gas from a lease, the lessee bears the risk that its decision may prove to be unprofitable. In other words, the value of its gas before processing (plus the costs of processing) may exceed the value that the lessee receives after processing--the value of the liquids and residue gas at the tailgate of the processing plant. 360 Absent any agreement to share in this risk (or to take in kind), a lessor should receive royalties based on the value of the ***96** gas at the wellhead--before processing. 361 Otherwise, the lessor may potentially share in the lessee's profits without sharing any of the lessee's risks. 362

Ninth, the doctrine yields illogical and inconsistent results. Common sense would suggest that a lessee should pay (a) essentially the same royalties for the same production from the same well, and (b) higher royalties for "higher quality" production than for "lower quality" production. Neither, however, necessarily holds true under the first marketable product doctrine. 363 In a first marketable ***97** state like Colorado or West Virginia, a lessee may have to pay higher royalties on gas that it sells at a downstream marketing location than on the same gas production--in the same quality and from the same well--that it sells at the wellhead. 364 By contrast, a lessee in a first marketable product state may have to pay largely the same, if not higher, royalties on sour gas than on sweet gas. Even though sour gas is "lower quality" production and not as desirable as sweet gas, 365 the first marketable product doctrine forbids a lessee from subtracting treating costs (i.e., its actual costs in treating sour gas to remove H_2S and other impurities) in its calculation of the value of its gas production. 366

***98** Tenth, the doctrine is bad policy. Because the first marketable product doctrine may require that lessees pay largely the same royalties on sour gas as on sweet gas, the doctrine encourages lessees to limit their production efforts to "higher quality" gas fields and avoid or abandon any production efforts in "lower quality" gas fields. 367 Additionally, because the doctrine may require that lessees pay higher royalties on production that they have treated to remove impurities, the doctrine encourages lessees to sell their production at the wellhead to purchasers who will themselves bear the responsibility for treating the production 368--at potentially ***99** greater cost to the ultimate consumer than if the lessees had treated the production. 369 Consequently, at a time when public policy should favor rules of law that would increase domestic oil and gas production and decrease post-production costs, the first marketable product doctrine instead creates the prospect for decreased domestic production and increased costs.

Professor Anderson has observed that "[o]il and gas resources are too strategically important to the future prosperity and security of the United States to leave this policy discussion solely in the hands of jurists." 370 Quite so. On the urging of a minority of commentators, a minority of courts adopted the first marketable product doctrine transparently for the purpose of giving royalty owners ***100** additional leverage in any royalty disputes with their lessees. But where a simple lever might have sufficed, these minority courts instead created a Hydra that will terrorize oil and gas jurisprudence for years to come. The first marketable product doctrine has many different heads, bears little or no resemblance to its ancestors, and creates much greater potential for harm than for good. However, unlike the mythical beast that roamed the swamps near Lerna, the first marketable product doctrine, having gained a toehold in several jurisdictions, is now likely immune even from the flaming torches of Hercules himself.

V. The Future: Identifying the "Product" in the First Marketable Product Doctrine

With the development of the first marketable product doctrine, a lessee must inevitably ask: "Now that the doctrine is here, what do we do with it?" To answer this question, a lessee (and, for that matter, a court in a royalty dispute) must recognize both what the doctrine is and what the doctrine is not. A lessee has no need to concern itself with the first marketable product doctrine--or, for that matter, the workback method for calculating royalties-- if it can ascertain the "value" of its production by selling it to an arm's-length purchaser at the wellhead. The first marketable product doctrine, like the workback method, is simply a device for determining the value of the lessee's production--the commodity that the lessor "conveys" to the lessee-- where the lessee has no potential buyer for its production at the wellhead. But while the workback method identifies the wellhead as the proper location for determining the value of the lessee's production, the first marketable product doctrine requires that the lessee determine the value of its production at the location where the lessee first acquires a marketable product.

Although the doctrine varies widely from court-to-court and commentator-to-commentator, in most of its permutations the doctrine does not demand that a lessee calculate its royalty payments on the basis of a price that it receives at a distant trading destination for products other than those that it extracted from the lease at the wellhead. As both Professor Kuntz and Professor Anderson have observed, the purpose of the first marketable product doctrine is not to allow lessors or royalty owners to share in the downstream profits of their lessees, but rather to determine the point at ***101** which lessees fulfill their obligation to achieve "production." 371 Under their explanation, the point at which a lessee achieves "production" is the proper location for calculating royalties. They contend that the lessee should calculate its royalty payments on the basis of the value of its production at the location where the lessee first obtains a marketable product from the oil or gas stream, and not automatically at the wellhead where the lessee still may need to do something to the oil or gas stream to secure a product that would attract a potential buyer. 372

Lessors in royalty litigation often use the term "marketable product doctrine" to refer to the "first marketable product doctrine." Their omission of the word "first" is significant. Although the first marketable product case law has not fully embraced the opinions of Professors Kuntz and Anderson, the case law--with the possible exception of Wellman in West Virginia--nonetheless recognizes that a lessee fulfills its duty to produce a marketable product once the lessee first obtains a marketable product from the oil or gas stream. 373 As the Colorado Supreme Court explained in Rogers, "royalty calculations should be made at the point where a first-marketable product has been obtained." 374 Even in those states that have adopted the first marketable product doctrine, the doctrine has not required that a lessee bear all of the expenses that it incurs after it has first produced a marketable product. 375

So just what is the "product" in the first marketable product doctrine? None of the various advocates of the doctrine has directly ***102** answered this question. That fact in itself may be yet another reason, even beyond those flaws in the doctrine that commentators have already identified, 376 to doubt that the doctrine offers a sound alternative to the historical precedent recognizing that lessees generally should pay royalties on the basis of the value or price of their production at the wellhead. The first marketable product case law tends to assume that a lease will produce only oil or only gas. Few wells, however, produce only oil or only gas. 377 After initial separation, an oil well may produce both crude oil and casinghead gas. 378 Likewise, after initial separation, a gas well may produce both gas and condensate. 379 Even after initial separation, a lessee may create still further "products" that did not necessarily exist in the gas stream at the point of extraction; for example, a lessee may process the gas that it produces from an oil well or gas well to manufacture natural gas liquids (NGLs). 380

If the first marketable product doctrine means anything at all, it should mean only that, absent express language to the contrary, the lessee may calculate its royalty payments at the point where it first removes a product from the oil or gas stream that it can sell in sufficient quantities to sustain its lease. 381 The typical lease contains a habendum clause providing that the lease will remain in effect through its primary term and so long thereafter as the lessee continues to produce oil, gas, or other minerals in paying quantities. 382 Even if the term "in paying quantities" does not itself appear in the habendum clause, the term will nonetheless arise in the ***103** habendum clause by implication. 383 "Paying quantities" is the point at which the revenues from a well exceed its operating costs. 384 "Wells do not have to pay out to be producing in paying quantities. They merely have to produce sufficient revenues over a reasonable period of time to cover all day-to-day operating expenses." 385

Once a lessee achieves "production" in paying quantities, the lessee fulfills the purpose that the parties intended to accomplish by entering into a lease in the first place. 386 When revenues exceed operating costs, the parties know that the lessee has drilled a successful well, and absent any necessity to shut in the well, the lessee at that point should begin paying royalties to the lessor on its successful production. Having obtained a product that will sustain the lease, the lessee should owe no duty to do anything further to the oil or gas stream, either by way of treating, processing, refining, or marketing the oil or gas stream. To the extent that the lessee chooses to alter the oil or gas stream beyond the point of "production," the lessee should not have to pay royalties on any value that it adds to its production downstream of the point where it first obtained a marketable product. 387

***104** The doctrine most certainly should not mean that a lessee must separately calculate royalties at each and every point where it may potentially obtain a marketable product. In recent royalty litigation, royalty owners have suggested that the first marketable product doctrine requires a lessee to pay royalties on each product that the lessee may obtain from the oil or gas stream and to calculate its royalties at each separate location where each product might be marketable--for example, at the separator for condensate, at the tailgate of the treating plant for gas, at the tailgate of the processing plant for NGLs, etc. Such an interpretation of the doctrine is both unwise and unworkable. Not only does it require the lessee to divine the proper royalty calculation point for each product that it may produce from the oil or gas stream, but it also allows a lessor to participate in the downstream profits of its lessee and to recover royalties on products, such as NGLs, that did not exist in the oil or gas stream at the point of extraction.

If courts in first marketable product states were to appreciate that the doctrine seeks only to determine the point of "production"--a big "if," in light of Rogers and Wellman --the doctrine, while continuing to suffer from a variety of flaws, would at least have a solid analytical foundation. Under such an approach, the lessee would continue to pay royalties on all marketable products that exist in the oil or gas stream at the point of extraction, but the lessee would calculate its royalty payments according to the value of those products at the point where it first acquired a marketable product that would sustain the lease. In particular, if the lessee were to acquire any further marketable products beyond the point where it first acquired a product that would sustain its lease, the lessee would determine its royalties on those products by calculating their value at the point of "production." In that event, the lessee could apply a workback method in which it took the sales price for each product at the final point of sale and subtracted all of the costs that the lessee incurred beyond the point where the lessee first acquired a marketable product that would sustain the lease.

As long as the first marketable product doctrine continues to exist, it must be internally consistent and intellectually honest. Otherwise, the doctrine is nothing more than a poorly disguised device to rewrite oil and gas leases in a way that permits royalty owners to participate in downstream activities for which they have shared none of the risks and assumed none of the costs.

***105** A. The First Product

Consider the following example: Texabama Gas enters into a lease in which it agrees to pay the lessor, Rustacre Land, a royalty of 1/8th of the market value of Texabama's production at the well. 388 Texabama drills a well on the leased property and begins to produce gas and other products from an underlying condensate reservoir. 389 Upon extracting the products from the well, Texabama sends the raw gas stream to separators, which remove all of the water and condensate from the gas stream. At the point of separation, Texabama collects the condensate, which comprises a substantial part of the gas stream, and sells it to a pipeline for an arm's-length market price. Texabama then sends the remaining gas stream to a treating facility, which removes hydrogen sulfide and other impurities from the stream. After treating the gas, Texabama sells the treated gas to a third party purchaser at a downstream commercial marketing center.

In a state that has rejected the first marketable product doctrine, Texabama may correctly use a workback method to calculate its royalty payments to Rustacre. Specifically, assuming that no purchaser or market is available at the wellhead, 390 Texabama may pay Rustacre 1/8th of the price that Texabama receives for its treated gas at the downstream commercial marketing center minus a proportional ***106** share of its separation, treating, and transportation costs. 391 In that event, a workback method properly compensates Rustacre for the production that Texabama actually acquires from Rustacre--a mix of sour gas and condensate. 392 To require Texabama to pay Rustacre on the basis of the price that Texabama receives for treated sweet gas (i.e., without any cost deductions) is to give Rustacre a windfall, akin to requiring that a forester pay a landowner a price based on the value of the cut treated lumber that the forester receives at the sawmill rather than the raw untreated wood that the forester removes from the landowner's property.

Nonetheless, even in a first marketable product state, Texabama should not have to pay royalties to Rustacre on the basis of the price that Texabama receives for its treated gas at a downstream market. Texabama's production from the lease includes a substantial amount of condensate, a light crude oil that a producer may separate from the natural gas stream. 393 Condensate is a potentially marketable product. 394 If the condensate in Texabama's production is sufficient to sustain Texabama's lease, the point at which it first obtains a marketable product is the location where Texabama separates the condensate from the gas stream. Texabama may then, as the above example suggests, choose to transport its remaining production downstream of the separators--and if it does so--Texabama may have to pay royalties on any further products it removes and sells from the gas stream. However, Texabama should calculate its royalties on those further products by determining***107** their respective value at the separators, where Texabama first acquired a marketable product--the condensate.

If, in the above example, Texabama received a price for its condensate that would have justified continued operations from the lease, it should pay Rustacre condensate royalties in the amount of 1/8th of the price that it actually receives for its condensate at the separators. On any remaining gas that Texabama sells at a downstream market, Texabama should calculate its royalties by determining the value of the gas at the point where it first obtained a marketable product. At the separators where Texabama first obtained a marketable product, it had not yet treated its gas to remove any impurities. Due to the fact that Texabama had no duty to do anything further to its gas stream after separating the condensate, it should calculate its gas royalties to Rustacre according to the value of its untreated sour gas at the point of production, by deducting all of its post-production costs downstream of the separators (i.e., its treating and transportation costs) from the price it receives for its treated sweet gas at the ultimate point of sale. 395

Even with this result, the first marketable product doctrine would still allow Rustacre to receive a windfall. In other words, Rustacre will not have to share the separation costs that Texabama must incur to remove the condensate from the gas stream. The resulting windfall, however, is at least consistent with the intent of the doctrine, which encourages lessees to "produce"--and to pay royalties on their "production"--in paying quantities sufficient to sustain a lease. Absent any express lease provision to the contrary, Texabama should not have to pay royalties on something other than its "production." Any interpretation of the first marketable product doctrine that would require Texabama to pay royalties on treated sweet gas would improperly require Texabama to pay royalties on a product it secures from the oil or gas stream beyond the point of "production."

B. A Product Marketable at the Wellhead

Consider another example: Continental Production Company executes a lease in which it agrees to pay the lessor, Joe Kuhl, a ***108** royalty of 1/8th of the market value of Continental's production at the well. Continental drills a well on the leased property and begins to produce sour gas from an underlying gas field. Genuine Gas Processors, a third party that owns a treating facility in the vicinity of the leased property, offers to buy the gas from Continental at the same price that Genuine pays to several other lessees for the same quality gas in the same field--$4.25 per MMBtu. Continental declines the offer and instead signs an agreement to have Genuine treat its gas at a cost of $.25 per MMBtu. After receiving the treated gas back from Genuine at the tailgate of the treating facility, Continental sells the treated gas to an arm's-length third party purchaser at a downstream commercial marketplace for $5.00 per MMBtu.

In a state that has rejected the first marketable product doctrine, Continental has no reason to apply a workback method to calculate the market value of its gas production. Instead, Continental may calculate its royalty payments to Kuhl on the basis of the price--$4.25 per MMBtu--that Genuine offered to pay Continental for its untreated gas at the wellhead. Even if Genuine had not extended an offer to buy Continental's gas production, Genuine has purchased gas of comparable quality, quantity, and availability from other producers in the same field. As long as Genuine's purchases were arm's-length transactions, its purchases amount to comparable sales that establish the market value of Continental's gas production at the wellhead. 396 Nothing more accurately gauges the market value of gas at the wellhead than the market itself--the prices that arm's-length purchasers actually paid in comparable transactions in the same field. 397

***109** The same should be no less true in a first marketable product state. The first marketable product doctrine determines the value of a lessee's production at the location where the lessee first acquires a marketable product. A lessee who can identify an arm's-length purchaser for its gas at the wellhead must, by definition, have a marketable product at the wellhead. 398 As Professor Anderson has explained:

> Where there are comparable arm's-length equivalent wellhead sales, the gas is clearly marketable at the wellhead. Moreover, these actual, arm's-length equivalent prices are available to directly determine the actual wellhead value of the gas in question. In other words, other than a deduction for the lessor's proportionate share of any production taxes chargeable to the lessor, a work-back calculation is neither necessary nor appropriate. The use of a comparable-sales approach seems fair to both the lessee and the lessor, and the use of actual comparable arm's-length equivalent sales prices should assure the lessor of a fair royalty share. 399

In the above example, Continental first acquired a marketable product at the wellhead, where Genuine offered to pay Continental $4.25 per MMBtu for its gas production.

The fact that Continental's gas is sour should not alter the conclusion that Continental's gas is marketable at the wellhead. Wood and Rogers have fostered the notion that "lower quality" production, such as sour gas, must necessarily be unmarketable. 400 Although a lessee may have a more difficult time finding a wellhead purchaser for sour gas as opposed to sweet gas, the notion that a lessee can never sell sour gas at the wellhead is untrue and should not form the basis for an inflexible doctrine of law. 401 Sour gas and ***110** other types of lower quality production may be attractive to wellhead purchasers who have invested the necessary capital to improve the quality of the production for resale at a downstream market. 402 If a lessee, like Continental in the above example, can find an arm's-length purchaser for its production at the wellhead, the lessee should be able to calculate its royalty payments based on the price that the purchaser was willing to pay at the wellhead.

C. A Product Other Than That Which Existed at the Wellhead

Next, consider this example: Cypress Lakes Operating Company enters into a lease in which it agrees to pay the lessor, Silverlake Holdings, Inc., a royalty of 1/8th of the market value of Cypress Lakes's production at the well. Cypress Lakes drills a well on the leased property and begins to produce gas from an underlying field. The gas that Cypress Lakes produces from its lease with Silverlake is "wet gas," containing concentrations of heavier hydrocarbons such as propane, butanes, and pentanes. 403 After extracting the gas from the ground and treating the gas to remove impurities, Cypress Lakes sends the gas stream to a processing facility, which removes the heavier hydrocarbons from the gas stream and uses them to manufacture NGLs. At the tailgate of the processing facility, Cypress Lakes receives both the NGLs and the residue gas remaining in the gas stream. 404 Cypress Lakes then ***111** separately sells the NGLs and the residue gas to third party purchasers at a downstream market.

In a state that has rejected the first marketable product doctrine, Cypress Lakes may calculate its royalty payments to Silverlake on the basis of the market value of its gas production at the wellhead. Assuming that Cypress Lakes cannot identify any comparable sales for its production, it may use the workback method to determine the market value of its production at the wellhead; specifically, Cypress Lakes may subtract its transportation, treating, processing, and other post-production costs from the price that it ultimately receives for its residue gas. 405 Cypress Lakes has no obligation to pay royalties on the NGLs that it receives at the tailgate of the processing facility. Absent a royalty clause expressly to the contrary, the only obligation that Cypress Lakes owes to its lessor is to pay royalties on the gas production that it extracts from the ground at the wellhead, not on any further value that Cypress Lakes adds to its production by processing its gas downstream of the wellhead. 406

Nor should a lessee have any obligation to pay royalties on NGLs in a first marketable product state. Heavier hydrocarbons, such as propane, butane, and pentanes, exist in a gaseous state in the gas stream. Processing the gas to manufacture NGLs changes the physical characteristics of these heavier hydrocarbons. 407 To ***112** manufacture NGLs, a facility must essentially cool the gas stream to a temperature at which most of the heavier hydrocarbons will liquify into a combined mass known as "raw make." The processing facility then must fractionate the "raw make" into its various component parts, which it may convert into NGLs. 408 Thus, while heavier hydrocarbons may exist in the gas stream at the wellhead, NGLs are not a "product" that exists in the gas stream at the wellhead; a processing facility must manufacture them from the heavier hydrocarbons. 409

Even under the first marketable product doctrine, a lessor may not claim a royalty interest in products other than those that the lessor "conveyed" to the lessee at the point of extraction, at least in the absence of a lease that specifically gives the lessor the right to participate in the lessee's downstream activities. 410 As Professor Kuntz recognized, "there is a distinction between acts which constitute production and acts which constitute processing or refining of the substance extracted by production." 411 The first marketable product doctrine seeks to determine the point at which a lessee achieves production --in other words, the point at which it first produces a marketable product. Processing, however, is not a production activity. 412 The act of processing does not fix or improve an ***113** existing product to make it marketable; instead, the act of processing extracts components from an existing product and uses them to manufacture new products that, the lessee hopes, will sell for a price exceeding the value of the unprocessed product. 413

Whether in a state that has rejected the first marketable product doctrine or in a state that has adopted it, a lessee should not have to share its downstream profits--particularly its profits on products other than those acquired from the lessor at the wellhead--with its royalty owners. 414 The result is no different even to the extent that the first marketable product doctrine arises from the implied covenant to market. A lessee must have a product to market before it has any duty to market the product. 415 In the above example, Cypress Lakes had at best only a duty to market--and to pay royalties on--the gas that it received from Silverlake at the wellhead, not on any NGLs that Cypress Lakes manufactured from the gas downstream of the wellhead. 416 Cypress Lakes had no duty to account to Silverlake for any profits that Cypress Lakes earned on products manufactured downstream of the wellhead through its ***114** own investment of capital and its own assumption of the risk of loss. 417

The product that Cypress Lakes received under its lease with Silverlake was "wet gas," which is normally marketable at the wellhead. 418 If Cypress Lakes's gas production was in fact marketable at the wellhead, it may use the comparable sales method to calculate its royalty payments to Silverlake. However, even if Cypress Lakes could not identify a purchaser for its gas production at the wellhead, it need not pay royalties on NGLs that it manufactured from the heavier hydrocarbons in the gas stream. Instead, Cypress Lakes should calculate its royalty payments based on the price of its gas where it first acquires a marketable product. 419 Specifically, if residue gas is the first marketable product that Cypress Lakes acquired from the gas stream, then it may determine the amount of its royalty payments under a simple calculation that multiplies the price that it received for its residue gas by the volume of its production at the wellhead.

D. An Inconsequential Product

Now, consider a final example: DG Production Company executes a lease agreeing to pay the lessor, Ian Audrey, a royalty of 1/8th of the market value of DG's production at the well. DG drills a well on the leased property and begins to produce sour gas from an underlying field. After extracting the gas from the ground, DG sends it to a treating facility, which removes small amounts of carbon dioxide and hydrogen sulfide from the gas stream. Lacking a market for the carbon dioxide, DG arranges for the treating facility to dispose of the carbon dioxide by venting it into the atmosphere. However, DG successfully sells the hydrogen sulfide to a third ***115** party that expresses an interest in converting the hydrogen sulfide into elemental sulfur. 420 Having removed the impurities from its gas stream, DG sells the treated gas to an arm's-length third party purchaser at a downstream commercial market.

Whether in a first marketable product state or otherwise, DG probably has no duty to pay royalties to Audrey on the carbon dioxide that it removes from the stream. Although DG must act as a reasonably prudent operator, the company does not have to elevate Audrey's interests over its own. 421 Audrey may not compel DG to conduct unprofitable operations, even if those operations might potentially benefit Audrey. 422 Thus, even assuming that DG hypothetically could have sold the carbon dioxide at a downstream market, DG may reasonably conclude--in light of the small amounts of carbon dioxide in the gas stream--that the costs of transporting the carbon dioxide to a downstream market would exceed its potential profit. In that event, the carbon dioxide has no "value" as a marketable commodity. 423 It is merely an inconsequential ***116** byproduct that the lessee, as a reasonably prudent operator, may properly remove from the gas stream to produce marketable sweet gas. 424

By comparison, DG will have to pay royalties on any hydrogen sulfide that it sells to a third party purchaser. Because DG removes only small amounts of hydrogen sulfide from the gas stream, the hydrogen sulfide is likely not a first marketable product that would in itself generate sufficient revenues to sustain the lease with Audrey. Nonetheless, the hydrogen sulfide is a product that exists in the gas stream at the wellhead. Having obtained that product from Audrey, DG must pay him a royalty share of any value or consideration that DG receives for that product. If DG's gas production is marketable at the wellhead, 425 it may calculate its hydrogen sulfide royalties at the wellhead, deducting a proportionate share of its costs in removing the hydrogen sulfide from the gas stream.

Otherwise, DG may simply pay Audrey a 1/8th share of the price that it actually receives upon selling its hydrogen sulfide to a third party purchaser.

VI. Conclusion

Although the relationship between a lessor and lessee focuses on the leased premises, the first marketable product doctrine allows a lessor to argue that the proper location for calculating royalties is a location downstream of the wellhead on the leased premises. While perhaps the epiphenomenon of good intentions, the first marketable product doctrine inevitably serves more harm than good.

The doctrine lacks a sound legal foundation. To the extent that it purports to rely on rules of contract construction, it does not give effect to the plain meaning of the term "at the well" in the standard royalty clause. To the extent that the doctrine purports to rely on the implied covenant to market, it improperly uses the covenant to ***117** reach a result different from that which the parties contemplated in the express terms of their lease agreement. Not surprisingly, the doctrine, having apparently failed to anticipate all of the circumstances in which lessors might seek to apply it, yields illogical and inconsistent results. As a result, the doctrine has clouded oil and gas royalty jurisprudence, bringing chaos to an area of the law that should demand uniform and consistent rules.

To the extent that some states continue to follow the first marketable product doctrine, the courts in those states should reexamine the analytical roots of the doctrine and seek to develop a body of case law that gives lessees clearer guidance for calculating royalty payments. In particular, courts in first marketable product states should define the parameters of the word "product." If the first marketable product doctrine means anything at all, it should mean only that the lessee may calculate its royalty payments at the point where it first obtains a marketable product--the location where it first removes a product from the oil and gas stream that it can sell in sufficient quantities to sustain the lease. The lessee should not have to pay royalties on any value that it adds to its production downstream of the point where it first obtains a marketable product. The first marketable product doctrine, if it is to be intellectually honest, should be more than a convenient excuse for allowing lessors to participate in the downstream profits of their lessees.

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[1]. See 3 Eugene O. Kuntz, A Treatise on the Law of Oil and Gas § 40.2(c), at 315-18 (Anderson Publ'g Co. 1989) [hereinafter 3 Kuntz, 1989 ed.] (identifying and explaining problems of construction associated with including a fixed gas royalty provision in a gas lease). Kuntz notes that

"the most important problem from the standpoint of modern practice is the problem of correlating the gas provision with the royalty provision on other substances." Id. at 315.

[2]. See infra text accompanying notes 50-51 (providing examples of market value royalty clauses pulled from actual leases).

[3]. See infra text accompanying notes 52-53 (giving examples of proceeds royalty clauses in leases).

[4]. Early in the history of oil and gas production in the United States, most leases contained fixed gas royalty clauses requiring the lessee to pay a periodic fixed royalty on gas production. At that time, "the primary objective of exploration and drilling operations was the discovery of oil, and it was justifiably regarded as a major misfortune if gas alone were found. Although the gas had value, it was difficult to market." 3 Kuntz, 1989 ed., supra note 1, § 40.1, at 311. Fixed gas royalty clauses fell out of use by the 1940s:

> As the natural gas industry developed and natural gas pipelines were extended over the country creating and expanding the market for gas, the value of gas increased. It also became apparent that the ultimate value of gas and the value of the right to extract and sell gas could not be foreseen or determined at any given time of leasing. Accordingly, instead of merely increasing the amount of the fixed periodic payment to be made as the gas royalty, the parties to oil and gas leases changed their practices and began to provide for a royalty on gas which is measured either by volume or by the value of the gas produced.

Id. at 312.

[5]. Professor David E. Pierce, from Washburn University School of Law, has observed that the relationship between lessors and lessees is the "classic uncooperative venture." David E. Pierce, The Royalty Value Theorem and the Legal Calculus of Post-Extraction Costs, 23 Energy & Min. L. Inst. § 6.01, at 152 (2003) (formerly named E. Min. L. Inst.) [hereinafter Pierce, The Royalty Value Theorem]. This observation is certainly true in the royalty context. Where the lessor and lessee are parties to a lease that ties royalty calculations to a yardstick such as "market value," common sense dictates that the lessee will favor an interpretation that reduces its royalty payments, while the lessor will favor an interpretation that would increase the lessee's royalty payments. Professor Pierce has described this inherent tension between the lessor and lessee as the Royalty Value Theorem: "When compensation under a contract is based upon a set percentage of the value of something, there will be a tendency by each party to either minimize or maximize the value." Id.; see also David E. Pierce, The Missing Link in Royalty Analysis: An Essay on Resolving Value-Based Royalty Disputes, 5 Tex. Wesleyan L. Rev. 185, 185 (1999) [hereinafter Pierce, The Missing Link] (explaining two methods of maximizing the landowner's royalty). In his explanation, Pierce states: "Once the oil and gas lease is entered into, and production has been obtained, there are only two ways a lessor can maximize his royalty income: (1) increase the volume of production; (2) increase the value of production." Id. Pierce further observes, "The situs of the lessor's volume- and value-enhancing efforts is often a courthouse." Id.

[6]. See Pierce, The Missing Link, supra note 5, at 187 (discussing the motivation of a lessor and lessee); see also David E. Pierce, From Extraction to Enduse: The Legal Background, Special Inst.

on Private Oil & Gas Royalties pt. 3, at 3-5 (Rocky Mtn. Min. L. Found. 2003) [hereinafter Pierce, From Extraction to Enduse] (illustrating the Royalty Value Theorem and the inherent conflict between the lessor and the lessee due to the theorem) (on file with the St. Mary's Law Journal).

[7]. See Pierce, From Extraction to Enduse, supra note 6, at 3-6 (noting that "[a]s a general proposition, as oil or gas moves downstream from the wellhead it increases in value"); see also Gary B. Conine, Crude Oil Royalty Valuation: The Growing Controversy over Posted Prices and Market Value, 43 Rocky Mtn. Min. L. Inst. § 18.04[2][a], at 18-25 (1997) [hereinafter Conine, Crude Oil Royalty Valuation] (stating that "[t]he closer a product moves to the place of consumption, the more valuable it becomes as a commodity").

[8]. See Black's Law Dictionary 1330-31 (6th ed. 1990) (defining royalty and proposing that a royalty is "reserved to [an] owner of land for permitting another to use the property"). By definition, a lessor is a royalty owner, assuming that the lessor has not conveyed all of its royalty interests. Id. However, not all royalty owners are lessors; some royalty owners, for instance, are overriding royalty interest owners. See Owen L. Anderson, Royalty Valuation: Should Overriding Royalty Interests and Nonparticipating Royalty Interests, Whether Payable in Value or in Kind, Be Subject to the Same Valuation Standard As Lease Royalty?, 35 Land & Water L. Rev. 1, 16-17 (2000) [hereinafter Anderson, Overriding Royalty Interests] (noting the distinctions between a lease royalty interest and an overriding royalty interest). Overriding royalty interest owners commonly acquire their interests by entering into an instrument that assigns them an "override" in an existing lease. See Bruce M. Kramer, Royalty Interest in the United States: Not Cut from the Same Cloth, 29 Tulsa L. Rev. 449, 456-57 (1994) [hereinafter Kramer, Royalty Interest] (discussing the differences between the terms "lease royalty" and "overriding royalty").

[9]. See Lynnette J. Boomgaarden, Shooting the Rapids Without Going Over the Brink: The "Where's" and "How's" of Gas Royalty Valuation, Special Inst. on Private Oil & Gas Royalties pt. 7, at 7-5 (Rocky Mtn. Min. L. Found. 2003) (recognizing that usually "[l]essors, seeking a share of any enhanced gas value as a result of post-extraction investment, want to locate the royalty valuation point as far downstream from the wellhead as possible") (on file with the St. Mary's Law Journal); Daniel M. McClure, Royalty Valuation and Payment Issues: Where Are We and Where Are We Headed?, 48 Rocky Mtn. Min. L. Inst. § 11.05[1][b], at 11-18 (2002) [hereinafter McClure, Royalty Valuation] (highlighting the basis of the dispute and observing: "As the lessee's role in adding value to gas extends further and further downstream, royalty owners have claimed the right to recover their 'share' of the added value, even though the original leases never contemplated that the royalty owner would share in this profit").

[10]. See infra text accompanying notes 118-19 (discussing the meaning of the term "at the well").

[11]. See infra text accompanying notes 193-308 (illustrating the differing approaches to the first marketable product doctrine in Kansas, Oklahoma, Colorado, and West Virginia).

[12]. See Pruitt v. Levi Strauss & Co., 932 F.2d 458, 466 (5th Cir. 1991) (Johnson, J., concurring in part and dissenting in part) (noting that the doctrine of stare decisis does not stand "as an insurmountable bar to the critical reexamination of flawed precedent").

[13]. See infra text accompanying notes 310-69 (listing the many flaws of that the first marketable product doctrine).

[14]. See infra text accompanying note 378 (recognizing that an oil well may produce both crude oil and casinghead gas).

[15]. See infra text accompanying note 379 (recognizing that a gas well may produce both gas and condensate).

[16]. Bruce M. Kramer, Modern Applications of the Rule Against Perpetuities to Oil and Gas Transactions: What the Duke of Norfolk Didn't Tell You, 37 Nat. Resources L.J. 281, 285 (1997).

[17]. Karolyn King Nelson, Takings Law West of the Pecos: Inverse Condemnation of Federal Oil and Gas Lease Rights, 37 Nat. Resources J. 253, 258 (1997). Karolyn King Nelson, now Karolyn King Gillespie, is one of the co-authors of this Article.

[18]. See Dayna Ferebee, Comment, Handshakes and Heartaches: Who Owns the Oil After Rogers v. Ricane?, 2 Tex. Wesleyan L. Rev. 129, 130-31 (1995) (describing oil and gas law as being "based on the uncomfortable marriage of contract and property law.... The oil and gas lease, like a conveyance, transfers an interest in property, but like a contract, contains conditions and covenants.").

[19]. See Jefferson D. Stewart & David F. Maron, Post-Production Charges to Royalty Interests: What Does the Contract Say and When Is It Ignored?, 70 Miss. L.J. 625, 629-30 (2000) (discussing how some states treat and classify the property interest created by an oil and gas lease).

[20]. E.g., Maralex Res., Inc. v. Gilbreath, 76 P.3d 626, 630 (N.M. 2003); Brown v. Haight, 255 A.2d 508, 510 (Pa. 1969); Anadarko Petroleum Corp. v. Thompson, 94 S.W.3d 550, 554 (Tex. 2002); Cherokee Water Co. v. Forderhause, 641 S.W.2d 522, 525 (Tex. 1982); see also Rock Island Oil & Ref. Co. v. Simmons, 386 P.2d 239, 241 (N.M. 1963) (stating that the law is well settled in New Mexico that an oil and gas lease creates a real property interest).

[21]. E.g., Garvan v. Kimsey, 389 S.W.2d 870, 871 (Ark. 1965); Gerhard v. Stephens, 442 P.2d 692, 704 (Cal. 1968); Miller v. Ridgley, 117 N.E.2d 759, 761 (Ill. 1954); Ralston v. Thacker, 932 S.W.2d 384, 387 (Ky. Ct. App. 1996); Doll v. Doll, 593 So. 2d 1239, 1246 (La. 1992); Shields v. Moffitt, 683 P.2d 530, 532 (Okla. 1984); Ready v. Texaco, Inc., 410 P.2d 983, 986 (Wyo. 1996).

[22]. See Ferebee, supra note 18, at 140 (discussing the differing positions, with regard to the time that title in the minerals vests, between states that either classify mineral interests as a fee simple determinable or a profit à prendre).

[23]. See id. at 139 (proclaiming that, "[i]n most instances, construing a mineral lease as creating a fee simple determinable or a profit à prendre results in a distinction without a difference").

[24]. Misha Ylette Mullins, Comment, Alabama Oil and Gas Law: Ownership or Nonownership After NCNB?, 48 Ala. L. Rev. 1065, 1067 (1997); see also Ralston, 932 S.W.2d at 387 (clarifying from the beginning of the court's analysis that "an oil and gas lease is an interest in real property").

[25]. Nelson, supra note 17, at 258-59. Indeed, if either the federal or state government were to forbid a lessee from exercising its property rights, the decision would effectively amount to a "taking" for which the lessee would be entitled to receive just compensation. Id. at 273; see also Whitney Benefits, Inc. v. United States, 926 F.2d 1169, 1172 (Fed. Cir. 1991) (reaffirming the definition of a legislative taking as "when economic development is effectually prevented," which the Federal Circuit set forth in Whitney Benefits, Inc. v. United States, 752 F.2d 1554, 1559 (Fed. Cir. 1985), a previous disposition of the instant case); Foster v. United States, 607 F.2d 943, 949 (Ct. Cl. 1979) (classifying a leasehold interest in the mineral rights as an estate in real property, compensable as a "taking" under the Fifth Amendment).

[26]. Wall v. United Gas Pub. Serv. Co., 152 So. 561, 563 (La. 1934); see also Stewart & Maron, supra note 19, at 630 (discussing expectations of the parties to a lease).

[27]. See David E. Pierce, The Renaissance of Law in the Law of Oil and Gas: The Contract Dimension, 42 Washburn L.J. 909, 930 (2004) [hereinafter Pierce, The Renaissance of Law] (providing an explanation of what the law has required from parties to a lease). Pierce explains:

> Even absent the commonly encountered "at the well" language, the entire oil and gas lease is structured around a relationship that begins, and ends, at the leased land. For example, the granting clause grants the lessee rights to explore, develop, and produce from, the leased land. The duration of the lease will continue only so long as there is production from the leased land. Activities to extend the lease beyond the stated term must take place on the leased land. Royalty is generated only from production that is obtained from the leased land.

Id. (footnote omitted); see also Pierce, The Missing Link, supra note 5, at 192 (noting that "[i]n most instances the oil and gas lease contemplates a relationship that begins, and ends, at the leased premises"). Consistent with this fact, most states have recognized that the proper venue for a royalty claim is the county where the well or leased property is located. E.g., Ala. Code § 9-17-33(e) (LexisNexis 2001); Ark. Code Ann. § 15-74- 603(a) (1994); Mont. Ann. Code § 82-10-101(1) (2003); N.D. Cent. Code § 47-16-39.1 (1999); Tex. Nat. Res. Code Ann. §91.404(c) (Vernon 2001 & Supp. 2004-05); Wyo. Stat. Ann. § 30-5-303(b) (2003); cf. Okla. Stat. Ann. tit. 52, § 529 (West 2000) (authorizing proper venue in the "county wherein the natural gas well or natural gas-gathering pipeline is situated," in an action brought for a failure of the well owner to meet its statutorily mandated duties).

[28]. See Richard B. Altman & Charles S. Lindberg, Oil and Gas: Non-Operating Oil and Gas Interests' Liability for Post-Production Costs and Expenses, 25 Okla. L. Rev. 363, 366-67 (1972) (recognizing the almost universal application of this principle); Scott Lansdown, The Marketable Condition Rule, 44 S. Tex. L. Rev. 667, 671 (2003) [hereinafter Lansdown, Marketable Condition Rule] (noting the historical recognition of valuation at the wellhead). Even where a lease did not include "at the well" royalty language or other language specifically identifying the point where the lessee was to calculate royalties, most courts "usually found that valuation at the well is consistent

with the intent of the parties." Id. at 671-72; see also La Fitte Co. v. United Fuel Gas Co., 284 F.2d 845, 849 (6th Cir. 1960) (affirming the district court's decision to consider the measurement of gas at the well as important and concluding that ultimately the well is both the marketplace and place of production for purposes of the royalty clause); Reed v. Hackworth, 287 S.W.2d 912, 913-14 (Ky. 1956) (stating that gas at the wellhead sets the price).

[29]. See Rechard v. Cowley, 80 So. 419, 419 (Ala. 1918) (discussing the fact that an oil and gas lease is a contract between the parties); Bi-County Properties v. Wampler, 378 N.E.2d 311, 314 (Ill. App. Ct. 1978) (noting that oil and gas leases are subject to the same rules of construction as contracts); Sabre Oil & Gas Corp. v. Gibson, 72 S.W.3d 812, 816-17 (Tex. App.--Eastland 2002, pet. denied) (construing a pooling provision in an oil and gas lease to determine the parties' intent and stating the presumption that "the parties to a contract intend every clause to have some effect" (emphasis added)); Moncrief v. Harvey, 816 P.2d 97, 103 (Wyo. 1991) (applying contract doctrines and noting the court's basic purpose is to determine the parties' intent); see also Jack O'Neill & Byron C. Keeling, Valuation of Oil Royalties: From the Perspective of the Payor, 47 Inst. on Oil & Gas L. & Tax'n § 6.05[1], at 6-41 (1996) ("An oil and gas lease is a contract, and as such, it is subject to the general principles of contract law.").

[30]. See David E. Pierce, Incorporating a Century of Oil and Gas Jurisprudence Into the "Modern" Oil and Gas Lease, 33 Washburn L.J. 786, 788- 89 (1994) [hereinafter Pierce, Incorporating a Century] (discussing the attributes of an oil and gas lease granting clause).

[31]. See Howard R. Williams & Charles J. Meyers, Manual of Oil and Gas Terms 974 (9th ed. 1994) (defining a royalty clause).

[32]. See Stewart & Maron, supra note 19, at 628 (explaining the typical oil and gas lease royalty clauses).

[33]. See John S. Lowe, Interpreting the Royalty Obligation: The Role of the Implied Covenant to Market, Special Inst. on Private Oil & Gas Royalties pt. 6, at 6-1 (Rocky Mtn. Min. L. Found. 2003) [hereinafter Lowe, Interpreting the Royalty Obligation] (discussing implied covenants and their effects) (on file with the St. Mary's Law Journal).

[34]. Id. The extent of recognition and manner of enforcement by the courts, for these implied covenants, differs from state to state. See Stirman v. Exxon Corp., 280 F.3d 554, 564 (5th Cir. 2002) (discussing some of the differences from state to state in the analysis of the implied covenant to market).

[35]. Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-2 n.3.

[36]. See Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 567 n.1 (Tex. 1981) (summarizing the implied covenants in an oil and gas lease); see also Patrick H. Martin, Implied Covenants in Oil and Gas Leases--Past, Present & Future, 33 Washburn L.J. 639, 641 (1994) (enumerating the implied covenants). Commentators have categorized these implied covenants in a variety of ways that differ only in organization, not in substance. See Richard W. Hemingway, The Law of Oil and Gas § 8.1,

at 541-42 (3d ed. 1991) (identifying three covenants with varying subparts); Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-2 n.3 (identifying six covenants). But see John Burritt McArthur, The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners, 41 Nat. Resources J. 795, 796 (2001) [hereinafter McArthur, The Mutual Implied Benefit Covenant] (urging that courts abandon the various separate implied covenants in favor of a single covenant requiring that operators "are to share benefits they receive with royalty owners and are not to take separate benefits from the revenue stream").

[37]. See Nelson v. Darling Shop of Birmingham, Inc., 157 So. 2d 23, 33 (Ala. 1963) ("Implied covenants are not favored."); see also Cent. States Prod. Corp. v. Jordan, 86 P.2d 790, 791 (Okla. 1939) (noting that the general rule is to favor express covenants over implied covenants).

[38]. See Brimmer v. Union Oil Co., 81 F.2d 437, 440 (10th Cir. 1936) ("An express covenant upon a given subject, deliberately entered into without fraud or mutual mistake, excludes the possibility of an implied covenant of a different or contradictory nature."); Meaher v. Getty Oil Co., 450 So. 2d 443, 446 n.2 (Ala. 1984) ("Where an express covenant is contrary to those implied in the lease, the express covenant shall supersede the implied covenant."); see also Connolly v. Samuelson, 671 F. Supp. 1312, 1318 (D. Kan. 1987) (emphasizing that courts do not find implied terms when express terms exist); Bourgeous v. Horizon Healthcare Corp., 872 P.2d 852, 856 (N.M. 1994) (discussing covenants and implied or express terms); Rogers v. Heston Oil Co., 735 P.2d 542, 546 (Okla. 1984) (questioning the effects of implied terms); Magnolia Petroleum Co. v. Page, 141 S.W.2d 691, 693 (Tex. Civ. App.--San Antonio 1940, writ ref'd) (stating that when express terms appear, implied terms disappear).

[39]. See Cont'l Potash, Inc. v. Freeport-McMoran, Inc., 858 P.2d 66, 80 (N.M. 1993) ("The general rule is that an implied covenant cannot coexist with express covenants that specifically cover the same subject matter."); Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373 (Tex. 2001) (acknowledging that "there is no implied covenant when the oil and gas lease expressly covers the subject matter of an implied covenant"); Terrell v. Lomas & Nettleton Fin. Corp., 496 S.W.2d 669, 672 (Tex. Civ. App.--Tyler 1973, writ ref'd n.r.e.) (observing that "the law is well settled that where a contract contains an express covenant upon a subject, no implied covenant can exist as to the same subject").

[40]. See John S. Lowe, Defining the Royalty Obligation, 49 SMU L. Rev. 223, 232 (1996) [hereinafter Lowe, Defining the Royalty Obligation] (describing recent case law involving the judicial construction of lease language as "a fictional intent unrelated to the reality of the transaction"). According to Lowe, "[l]itigation over the oil and gas lease royalty obligation shows the judicial construction process at its worst. In the context of royalty litigation, different courts have applied the same fundamental principles of judicial construction differently and have reached disparate and confusing results." Id.

[41]. O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6-4.

[42]. Union Pac. Res. Group, Inc. v. Neinast, 67 S.W.3d 275, 279 (Tex. App.--Houston [1st Dist.] 2001, no pet.).

[43]. Kramer, Royalty Interest, supra note 8, at 454.

[44]. See O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6-5 (recognizing that, although most royalty clauses provide a lessor with a royalty interest from production, "the terms governing the nature of the royalty interest will vary in length, language and scope").

[45]. Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 125 (Tex. 1996) (Owen, J., concurring).

[46]. See O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6-5 to -8 (discussing these two categories of royalty clauses). Some leases contain "hybrid" royalty clauses that require monetary royalties under some circumstances and in kind royalties under other circumstances. For instance, some leases may give the lessor the right to decide, at its discretion, to receive in kind royalties instead of monetary royalties. In that situation, the rules that will govern the lessee's payment obligations will depend on whether the lessor elects to receive in kind royalties or monetary royalties.

[47]. Id. at 6-8.

[48]. See supra notes 1 & 2 and accompanying text (discussing the history of oil and gas royalty payment calculations).

[49]. See Kramer, Royalty Interest, supra note 8, at 459 (explaining the difference between market value and market price). Technically, the terms "market value" and "market price" are distinguishable. Id. "Market price seemingly refers to an actual sale of the gas in exchange for a cash consideration. Thus without a sale there is no market price. Market value, however, may exist in the absence of an actual sale because it is based on a hypothetical standard." Id.; accord Atl. Richfield Co. v. Farm Credit Bank of Wichita, 226 F.3d 1138, 1166 n.14 (10th Cir. 2000) (noting that the terms market value and market price are not always synonymous); Hugoton Prod. Co. v. United States, 315 F.2d 868, 874 (Ct. Cl. 1963) (explaining that, "although the market value of gas at the wellhead is the amount that could be obtained for it under a new contract at any given time, the representative price is the price which is in fact being obtained under all existing comparable contracts"), modified, 349 F.2d 418 (Ct. Cl. 1965); Hemingway, supra note 36, § 7.4(B), at 399 (discussing market price and proffering that "[p]rice refers to actual sales; value or worth relates to opinion"). Many courts, however, have used the two terms interchangeably. See, e.g., Sartor v. United Gas Pub. Serv. Co., 84 F.2d 436, 440 (5th Cir. 1936) (interchanging value and price); Ark. Natural Gas Co. v. Sartor, 78 F.2d 924, 927 (5th Cir. 1935) (applying market price and market value as synonymous terms).

[50]. Kramer, Royalty Interest, supra note 8, at 455 (quoting from the lease form at issue in Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 228 (5th Cir. 1984)).

[51]. 3 Howard R. Williams & Charles J. Meyers, Oil and Gas Law § 642.2, at 504 (2004) [hereinafter 3 Williams & Meyers] (citing a portion of the lease in Evangelical Lutheran Church v. Stanolind Oil & Gas Co., 251 F.2d 412, 417 (8th Cir. 1958)). In lieu of tying royalties to market value or market price, some oil royalty clauses require that lessees calculate their royalty payments on the basis of a posted price. For example:

> [The lessee covenants to] pay Lessor monthly as royalty the equal [one-eighth] part of the value of all oil produced and saved ... upon the leased premises ... at the posted available market price of the district in which the premises are located for oil of like gravity, the day the oil is run into purchaser's pipe line or storage tanks ....

Id. at 502.3 (quoting the lease from Vedder Petroleum Corp. v. Lambert Lands Co., 122 P.2d 600, 601-02 (Cal. Dist. Ct. App. 1942)). "Posted prices" are prices that major crude oil purchasers publish--usually by "posting" them on their websites--as benchmark prices for crude oil from particular fields. See Conine, Crude Oil Royalty Valuation, supra note 7, § 18.01, at 18-2 to -3 n.1 (discussing the posted price). Posted prices are relevant in determining the market value of crude oil. Diamond Shamrock Exploration Co. v. Hodel, 853 F.2d 1159, 1166 (5th Cir. 1988). However, the term "posted price" does not mean precisely the same thing as "market value." Koch Indus., Inc. v. Nat'l Union Fire Ins. Co., No. 89-1158-K, 1989 WL 158039, at *19 (D. Kan. Dec. 21, 1989).

[52]. Martin v. Glass, 571 F. Supp. 1406, 1410 (N.D. Tex. 1983).

[53]. 3 Williams & Meyers, supra note 51, § 642.2, at 506 (citing a New York and Pennsylvania lease form).

[54]. See Boomgaarden, supra note 9, at 7-10 (discussing market value and proceeds). Some royalty clauses may require the lessee to apply different yardsticks in different circumstances. For instance, some leases contain "two-pronged" royalty clauses that include two different subdivisions: a subdivision that requires the lessee to pay royalties on the basis of the "market value" of oil or gas that it sells or uses off of the leased premises, and a subdivision that requires the lessee to pay royalties on the basis of the "proceeds" that it receives for oil or gas that it sells on the leased premises. Michael P. Irvin, The Implied Covenant to Market in the Deregulated Natural Gas Industry, 42 Rocky Mtn. Min. L. Inst. § 18.03[4], at 18-26 to -27 (1996); see also Pierce, From Extraction to Enduse, supra note 6, at 3-16 (noting the approaches).

[55]. See Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 372 (Tex. 2001) ("Market value may be wholly unrelated to the price the lessee receives as the proceeds of a sales contract."); see also Hemingway, supra note 36, § 7.4(C), at 401 (noting that "[t]he price of a product may or may not reflect the intrinsic value of it"); Irvin, supra note 54, § 18.03[1], at 18-21 ("This type of royalty clause [a 'market value' royalty clause] ... generally requires a determination of the worth of the gas independent of the compensation therefor received by the lessee."). Because "market value" is not the same thing as "proceeds," most courts have concluded that "market value" royalty clauses are distinguishable from "proceeds" royalty clauses. E.g., Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 236 (5th Cir. 1984); Mont. Power Co. v. Kravik, 586 P.2d 298, 302 (Mont. 1978); West v. Alpar Res., Inc., 298 N.W.2d 484, 487 (N.D. 1980); Tex. Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 871 (Tex. 1968); see also Yzaguirre v. KCS Res., Inc., 47 S.W.3d 532, 539 (Tex. App.--Dallas 2000) ("Under a market value royalty, the lessor receives a royalty based on the current market value for the oil and gas. In contrast, a royalty based on proceeds is calculated on what the lessee actually receives for the oil and gas."), aff'd, 53 S.W.3d 368 (Tex. 2001). Courts in some states, however, have declined to distinguish between "market value" and "proceeds" royalty clauses. In those states that do not distinguish between "market value" and "proceeds," the price that a lessee receives for the sale of oil or gas under an arm's-length contract automatically establishes, as a matter

of law, the market value of the oil or gas. E.g., Hillard v. Stephens, 637 S.W.2d 581, 585 (Ark. 1982); Tara Petroleum Corp. v. Hughey, 630 P.2d 1269, 1272 (Okla. 1981).

[56]. See Irvin, supra note 54, § 18.03[3], at 18-24 (discussing how market value and price determinations are frequently litigated).

[57]. This example is taken from a lease form for Temple-Inland Forest Products Corporation 1-3, executed March 1, 1995 (on file with the St. Mary's Law Journal).

[58]. See 3 Kuntz, 1989 ed., supra note 1, § 39.4(b), at 296 (stating that "the lessee becomes the owner of the oil produced"); see also Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 160-61 (discussing a monetary royalty clause with regard to the lessee's and lessor's interests). Pierce states the following:

> Upon production the lessor has no ownership interest in the gas; 8/8ths of the gas belongs to the lessee and the lessor merely has a contractual right to a cash payment that accrues as gas is extracted. Many lease forms do not even require the lessee to sell the gas in order to trigger a royalty obligation.

Id.

[59]. Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 159 n.18; see also Atwood v. Humble Oil & Ref. Co., 338 F.2d 502, 510 (5th Cir. 1964) (holding that plaintiffs cannot complain of conversion when all they are entitled to is money). Wyoming apparently recognizes a contrary rule; a royalty owner may bring a conversion action to recover unpaid monetary royalties. See Ferguson v. Coronado Oil Co., 884 P.2d 971, 975-77 (Wyo. 1994) (analyzing the language of the lease in question and determining that the royalty reserved was a "separate identifiable personal property right"); Young v. Young, 709 P.2d 1254, 1257-58 (Wyo. 1985) (finding all of the elements for a conversion cause of action were present).

[60]. See 3 Kuntz, 1989 ed., supra note 1, § 39.1(a), at 263-64 (proposing that the uniform method of describing oil royalties includes a royalty clause demanding the lessee to "deliver to the lessor a portion of the oil produced and saved" (emphasis added)); 1 Ernest Smith & Jacqueline Weaver, Texas Law of Oil and Gas § 4.6(A), at 4-58 (2d ed. 2004) [hereinafter 1 Smith & Weaver] (discussing the traditional practice of oil royalties being payable in kind). This Article will use the term "royalty oil" to refer to the lessor's proportional share of production under an "in-kind" royalty clause. Despite the fact that "in-kind" royalty terms more commonly appear in oil royalty clauses, some leases allow lessors the option to receive gas production in kind. See Edward B. Poitevent, II, Post-Production Deductions from Royalty, 44 S. Tex. L. Rev. 709, 715 (2003) (claiming that there is an increased practice of allowing the lessor to receive gas royalties in kind, although these royalties are usually paid in cash).

[61]. See 1 Smith & Weaver, supra note 60, § 4.6(A), at 4-58 (defining the lessor's entitlement under an in-kind royalty clause).

[62]. See 3 Williams & Meyers, supra note 51, § 642.5, at 511-12 (asserting variants of an in-kind oil royalty clause and addressing the delivery of the oil to the lessor); Daniel M. McClure,

Developments in Oil and Gas Class Action Litigation, 52 Inst. on Oil & Gas L. & Tax'n § 3.06[1][a], at 3-24 (2001) [hereinafter McClure, Developments] (describing delivery of oil under an in-kind lease).

[63]. 3 Kuntz, 1989 ed., supra note 1, § 39.2(a), at 283 (citing Shreveport-El Dorado Pipe Line Co. v. Bennett, 290 S.W. 929, 930 (Ark. 1927)).

[64]. Id. (citing Roy v. Ark.-La. Gas Co., 7 So. 2d 895, 896 (La. 1942)).

[65]. Id. § 39.2(b), at 285; James C.T. Hardwick, Private Landowner Royalties on Oil--Theory and Reality, Special Inst. on Private Oil & Gas Royalties pt. 10, at 10-4 (Rocky Mtn. Min. L. Found. 2003) (asserting that an in-kind royalty clause confers actual ownership of the oil produced to the lessor) (on file with the St. Mary's Law Journal); see also Shreveport-El Dorado Pipe Line Co. v. Bennett, 290 S.W. 929, 930-32 (Ark. 1927) (refusing to recognize the lessee's claimed ownership of all the oil and gas under in-kind terms of a lease and finding title to a 1/8 interest in the lessor); Hager v. Stakes, 116 Tex. 453, 294 S.W. 835, 840-41 (1927) (concluding that the in-kind royalty provision from the lease reserved a 1/8 "realty" interest in the mineral estate to the lessor). But see Laura H. Burney, The Interaction of the Division Order and the Lease Royalty Clause, 28 St. Mary's L.J. 353, 430 (1997) (arguing that "courts should not view the in-kind royalty option as a reservation of title to the oil, but instead, as establishing a payment method for the consideration referred to in the granting clause, the royalty").

[66]. See 3 Kuntz, 1989 ed., supra note 1, § 39.2(b), at 286 (discussing the numerous causes of action that may arise through the breach of an oil and gas lease and proposing that breach of an in-kind royalty clause can amount to conversion); Hardwick, supra note 65, at 10-5 (claiming that the purchaser of crude oil may be liable to a lessor in conversion in some instances); see also Clark v. Slick Oil Co., 211 P. 496, 501 (Okla. 1922) (stating that a conversion claim may arise).

[67]. See 3 Williams & Meyers, supra note 51, § 642.5, at 514 (giving typical examples from oil and gas leases to illustrate one of the variants-- place of delivery--of an in-kind royalty provision). A lessor who physically receives possession of his royalty oil may, of course, make his own arrangements to sell his royalty oil to a third party purchaser--at his own risk. McClure, Developments, supra note 62, § 3.06[1][a], at 3-24.

[68]. See 3 Williams & Meyers, supra note 51, § 642.5, at 514 (providing an example of a lease provision that allows delivery of the oil, by the lessee, to third parties). "As a practical matter, most royalty owners lack the resources to receive delivery of oil in kind." O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6-6. If a lessor has made no arrangements to take or store royalty oil, the lessee has the implied authority to sell the lessor's royalty oil along with the lessee's share of production. Hardwick, supra note 65, at 10-21 n.98; see also Wolfe v. Tex. Co., 83 F.2d 425, 430-31 (10th Cir. 1936) (finding that acquiescence allows the lessee to sell the oil when no storage is provided by the lessor); Pierce, Incorporating a Century, supra note 30, at 818 (stating that a lessee can market a lessor's share).

[69]. Howard R. Williams & Charles J. Meyers, Manual of Oil and Gas Terms 299 (9th ed. 1994) (defining "division order" and stating that the third party purchaser will usually require all royalty owners to execute the order).

[70]. See Hardwick, supra note 65, at 10-7 (discussing what the terms of division orders warrant); O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6- 7 n.30 (describing the sale of a royalty to a pipe line purchaser). "[D]ivision orders represent distinct sales contracts in which crude oil royalty owners ... sell their oil to the producer or a third party under a stipulated pricing formula." McClure, Developments, supra note 62, § 3.06[1] [g], at 3-32; see also Stanolind Oil & Gas Co. v. Terrell, 183 S.W.2d 743, 745 (Tex. Civ. App.--Galveston 1944, writ ref'd) (defining a division order as "the contract under which the production is purchased or accepted for transportation by the pipe line company"); cf. Ala. Code Ann. § 9-17-33 (2001) (defining a division order); Tex. Nat. Res. Code Ann. § 91.402(d) (Vernon 2001 & Supp. 2004-05) (stating that a division order may be used, giving the provisions that the division order must include, and providing a form division order). Some cases and commentators have suggested that a division order is a contract for the sale of goods under Article 2 of the Uniform Commercial Code. See, e.g., Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 231-32 (5th Cir. 1984) (citing to Miss. Code Ann §75- 2-107(1) (1981), the Mississippi statutory equivalent of U.C.C. § 2-107(a)); see also McClure, Developments, supra note 62, § 3.06[1][e][ii], at 3-30 to - 31 (proposing that "[a] lessor's sale of his in-kind share under a division order" is a U.C.C. contract). However, that proposition appears to be true only if one properly deems the lessor as a participant in the process of severing the oil or gas from the mineral estate. See U.C.C. § 2-107 cmt. 1 (2000) (noting that a sale of oil or gas that has not yet been produced as of the date of the transaction is only a U.C.C. contract for the sale of goods if the minerals are severed by the seller); O'Neill & Keeling, supra note 29, § 6.05[4], at 6-47 (discussing U.C.C. § 2-107 (1978) and explaining that, regardless of whether the royalty clause required a money payment, "the royalty owner (the 'seller') does not himself sever the royalty oil from the ground").

[71]. See Hardwick, supra note 65, at 10-6 to -8 (outlining the historical crude oil division order). Hardwick asserts the following:

> The traditional crude oil division order will typically specify that the oil run will become the property of the division order holder, usually specifying the point or location at which title to the oil will pass to the purchaser and will specify the basis upon which payment is to be made.

Id. at 10-7; see also Exxon Corp. v. Middleton, 613 S.W.2d 240, 250-51 (Tex. 1981) (noting that payments made in accordance with a division order are "final and binding").

[72]. See Hardwick, supra note 65, at 10-7 to -8 (enumerating variations found by the author after reviewing numerous division orders); McClure, Developments, supra note 62, § 3.06[1][g], at 3-32 to -33 (enumerating typical pricing terms included in division orders). Several states have enacted division order statutes that limit the purpose and use of division orders. Hardwick, supra note 65, at 10-12. Most of these statutes forbid lessees from using division orders as an indirect means of amending or altering their lease terms with their lessors. Id. These statutes do not appear to inhibit purchasers, especially third party purchasers, from using division orders to specify the terms for a purchase of crude oil. Id.

> Arguably, however, neither these statutory definitions nor prohibitions against lease amendment would preclude the inclusion in a crude oil division order of provisions for the passage of title and the terms upon which the royalty owner is to be paid because the traditional crude oil royalty clause contains no provisions directing how the royalty share of production is to be purchased - at least where a third-party purchaser is concerned - or the value that is to be given that share of production.

Id.

[73]. See 3 Kuntz, 1989 ed., supra note 1, § 39.2, at 289 ("A lessor may waive the right to royalty in kind during such time as payments are accepted in cash under a division order ....").

[74]. Id.; see also Hardwick, supra note 65, at 10-13 (examining producer-operator division orders and addressing the situation where the operator is also the lessee).

[75]. See Gilmore v. Superior Oil Co., 388 P.2d 602, 606 (Kan. 1964) ("Kansas has always recognized the duty of the lessee under an oil and gas lease not only to find if there is oil and gas but to use reasonable diligence in finding a market for the product."); Severson v. Barstow, 63 P.2d 1022, 1024 (Mont. 1936) ("Where, as here, the principal consideration for a lease is the payment of royalty, the lease carries an implied covenant to use reasonable diligence to market the product when produced ...."); Libby v. De Baca, 179 P.2d 263, 265 (N.M. 1947) (emphasizing that "[a lessee] must proceed with reasonable diligence, as viewed from the standpoint of the reasonably prudent operator ... to market the product"); cf. McVicker v. Horn, Robinson & Nathan, 322 P.2d 410, 416 (Okla. 1958) (applying an implied covenant to market); Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 567 (Tex. 1981) (discussing the history of lease obligations and covenants, including the implied covenant to market); Phillips v. Hamilton, 95 P. 846, 848 (Wyo. 1908) (asserting an implied duty to market with reasonable diligence).

Although most states have held that implied covenants may arise in a lease relationship (whether implied "in fact" or implied "in law"), some states have not specifically recognized the implied covenant to market as one of the covenants that may arise in the lease relationship. See, e.g., Sheffield v. Exxon Corp., 424 So. 2d 1297, 1299-1301 (Ala. 1982) (discussing the implied covenant of protection against drainage, but not the implied covenant to market); Hartman Ranch Co. v. Associated Oil Co., 73 P.2d 1163, 1166 (Cal. 1937) (discussing the implied covenant of exploration and protection against drainage, but not the implied covenant to market); see also Stirman v. Exxon Corp., 280 F.3d 554, 564-66 (5th Cir. 2002) (classifying states on the basis of whether the state imposes an implied covenant to market and identifying Alabama, California, Florida, Mississippi, and North Dakota as states that have not specifically recognized the implied covenant to market).

[76]. Irvin, supra note 54, § 18.02[2], at 18-11 (emphasis added).

[77]. See Brian S. Tooley & Keith D. Tooley, The Marketable Product Approach in the Natural Gas Royalty Case, 44 Rocky Mtn. Min. L. Inst. § 21.02, at 21-3 (1998) (asserting that "the mutual benefit of the lessor and lessee" is the fundamental purpose behind an oil and gas lease).

[78]. Id.; see also Hemingway, supra note 36, § 8.9(C), at 577 (noting that the implied covenant to market may arise when the lessor "will not receive any benefit from the lease" without marketing).

The implied covenant to market traditionally arises only where the lessee's marketing efforts would potentially affect the lessor's royalties. Cf. Tooley & Tooley, supra note 77, § 21.02, at 21-4 to -5 (indicating that courts do not give deference to the marketing decisions of the lessee when the lessee's and lessor's interests under the lease are divergent). Therefore, the implied covenant to market should not arise when the lessor agrees to take possession of its royalty oil at the wellhead under an in-kind royalty clause. See supra note 67 and accompanying text (discussing the fact that the lessor assumes responsibility of the oil once it accepts delivery of the product in kind).

[79]. See El Paso Natural Gas Co. v. Am. Petrofina Co., 733 S.W.2d 541, 550 (Tex. App.--Houston [1st Dist.] 1986, writ ref'd n.r.e.) (recognizing that the implied covenant to market rests on the proposition that a lessee may not act in a way that would unfairly reduce the lessor's royalty payments).

[80]. 45 A. 54 (Pa. 1899).

[81]. See Iams v. Carnegie Natural Gas Co., 45 A. 54, 55 (Pa. 1899) (refusing to disturb the jury verdict after the trial court decided to instruct the jury that, if it found "gas had been obtained in paying quantities, the [lessee] was bound to market it"); see also Bruce M. Kramer & Chris Pearson, The Implied Marketing Covenant in Oil and Gas Leases: Some Needed Changes for the 80's, 46 La. L. Rev. 787, 792 (1986) (tracing the history of the implied marketing covenant back to Iams).

[82]. See Iams, 45 A. at 54 (interpreting a lease clause that required the lessee to pay consideration "for the gas from each well, so long as it shall be sold therefrom"). The lease in Iams is an example of an older lease with a fixed gas royalty clause. See supra note 4 (explaining the early history of gas royalty clauses in the United States).

[83]. Iams, 45 A. at 54.

[84]. Id. at 55.

[85]. Id. (emphasis added) (quoting Glasgow v. Chartiers Oil Co., 25 A. 232, 232 (Pa. 1892)).

[86]. Kramer & Pearson, supra note 81, at 797 (quoting 7 Howard R. Williams & Charles J. Meyers, Oil and Gas Law § 699.1 (1983)).

[87]. Id. at 793; see also Pierce, Incorporating a Century, supra note 30, at 806 (identifying that a lease generally provides for termination if there is no production in paying quantities).

[88]. Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987).

[89]. See Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-4 to -6 (discussing how courts have interpreted the reasonable amount of time standard); Tooley & Tooley, supra note 77, § 21.02, at 21-4 (reiterating that the implied covenant requires "due diligence to market production within a reasonable time").

[90]. Tooley & Tooley, supra note 77, § 21.02, at 21-4.

[91]. Cf. Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-5 to -6 (discussing shut-in royalty clauses and concluding that they do not relieve the lessee's duty to market).

[92]. See Bristol v. Colo. Oil & Gas Corp., 225 F.2d 894, 896 (10th Cir. 1955) (outlining the general requirement of using due diligence to market the product upon discovery); Robbins v. Chevron U.S.A., Inc., 785 P.2d 1010, 1014 (Kan. 1990) (recognizing that a lease agreement includes a covenant to use due diligence to market the product); Swamp Branch Oil & Gas Co. v. Rice, 70 S.W.2d 3, 5 (Ky. 1934) (expressing that a lessee must diligently pursue a market once oil or gas is discovered); Hutchinson v. Atlas Oil Co., 87 So. 265, 270 (La. 1921) (stating the need for due diligence to explore markets for newly discovered oil, gas, or both).

[93]. See Tooley & Tooley, supra note 77, § 21.02, at 21-4 (discussing a lessee's duty "to exercise reasonable diligence to sell production within a reasonable time," after discovering the product, under the implied covenant to market). If the lessee discovered oil or gas in paying quantities, it could not skirt its duty to market simply by paying "shut-in" royalties to the lessor. See Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-6 ("[T]he purpose of the shut-in royalty clause is to protect the lessee against loss of the lease for failure of production where marketing is not possible or advisable, not to relieve the lessee of the duty to market.").

[94]. Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-15 to -17; Tooley & Tooley, supra note 77, § 21.02, at 21-4.

[95]. El Paso Natural Gas Co. v. Am. Petrofina Co., 733 S.W.2d 541, 550 (Tex. App.--Houston [1st Dist.] 1986, writ ref'd n.r.e.).

[96]. See supra text accompanying notes 52-53 (discussing proceeds royalty clauses).

[97]. Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987); see also Craig v. Champlin Petroleum Co., 300 F. Supp. 119, 125 (W.D. Okla. 1969) (stating that a lessee is obligated to find a market at the "prevailing market price"), rev'd on other grounds, 435 F.2d 933 (10th Cir. 1971). Generally, a lessee may fulfill this duty by selling its production at the prevailing market price. See Cook v. Tompkins, 713 S.W.2d 417, 421 (Tex. App.-- Eastland 1986, no writ) (holding that a lease operator complied with the covenant when it sold oil at market price). However, a lessee does not necessarily violate this duty by failing to sell its production at the prevailing market price. See Amoco Prod. Co. v. First Baptist Church, 611 S.W.2d 610, 610 (Tex. 1980) (asserting that "[a]lthough, in a proper factual setting, failure to sell at market value may be relevant evidence of a breach of the covenant to market in good faith, it is merely probative and is not conclusive"). The best price is not always the same as the highest price. See Judith M. Matlock, Payment of Gas Royalties in Affiliate Transactions, 48 Inst. on Oil & Gas L. & Tax'n § 9.06[3], at 9-48 (1997) (declaring that "[t]he implied covenant to market has never required a producer to get the highest price in a vacuum"). Under certain circumstances, the fact that a contract offers an attractive price may not mean that the contract is the most prudent option. See Parker v. TXO Prod. Co., 716 S.W.2d 644, 645-47 (Tex. App.-- Corpus Christi 1986, no writ) (holding that the evidence was

sufficient to show that the lessee had acted prudently even though it had accepted a price five percent below market value); see also Conine, Crude Oil Royalty Valuation, supra note 7, § 18.04[4], at 18-35 (noting that a short-term purchase contract, while potentially offering the prospect of a high purchase price, may not be as prudent as a long-term contract that allows a lessee "to remain with one purchaser ... and to ride out variations in [the purchaser's] pricing structure").

[98]. See Scott Lansdown, The Implied Marketing Covenant in Oil and Gas Leases: The Producer's Perspective, 31 St. Mary's L.J. 297, 348-49 (2000) [hereinafter Lansdown, Implied Marketing Covenant] (echoing that the implied covenant "says nothing about the obligation of a lessee to employ a particular mechanism to calculate royalty"). But see Maurice H. Merrill, The Law Relating to Covenants Implied in Oil and Gas Leases § 85, at 214-18 (2d ed. 1940) [hereinafter Merrill, 2d ed.] (advocating a broader definition of the implied covenant to market).

[99]. See Iams v. Carnegie Natural Gas Co., 45 A. 54, 54 (Pa. 1899) (opining that once the landlord and tenant relationship was established, the tenant had to act on behalf of the common good).

[100]. Amoco Prod. Co. v. First Baptist Church of Pyote, 579 S.W.2d 280, 285 (Tex. Civ. App.--El Paso 1979), writ ref'd n.r.e., 611 S.W.2d 610 (Tex. 1980) (per curiam), abrogated on other grounds by Amoco Prod. Co. v. Alexander, 622 S.W.2d 563 (Tex. 1981); see also Conine, Crude Oil Royalty Valuation, supra note 7, § 18.04[4], at 18-35 (stressing that a lessee is not required to incur additional expense to appease a lessor).

[101]. Lansdown, Implied Marketing Covenant, supra note 98, at 318 (footnote omitted).

[102]. Iams, 45 A. at 54-55.

[103]. Kramer & Pearson, supra note 81, at 794.

[104]. Smith v. Amoco Prod. Co., 31 P.3d 255, 268 (Kan. 2001); Danciger Oil & Ref. Co. v. Powell, 137 Tex. 484, 154 S.W.2d 632, 635 (1941); see also Hemingway, supra note 36, § 8.1, at 543 ("It appears that the majority view is that implied covenants are implied in fact and not in law." (footnote omitted)). Maurice Merrill, a professor at the University of Oklahoma School of Law, advocated a contrary view, arguing that the implied covenant to market should be "implied in law." Merrill, 2d ed., supra note 98, § 220, at 463-64; see also infra text accompanying notes 146-54 (explaining Merrill's "implied-in-law" approach to implied covenants). Until the rise of the first marketable product doctrine, however, Professor Merrill's argument "found no support ... in the adjudicated cases." Smith, 31 P.3d at 268.

[105]. Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-31; cf. 5 Howard R. Williams & Charles J. Meyers, Oil and Gas Law § 803, at 18.3 (2004) [hereinafter 5 Williams & Meyers] ("A covenant is implied in fact when its existence is derived from the written agreement and the circumstances surrounding its execution.").

[106]. Smith, 31 P.3d at 265; accord Kennedy v. Forest, 930 P.2d 1026, 1029 (Idaho 1997) (establishing that an implied-in-fact covenant's terms are inferred from the parties' conduct); Garcia

v. Middle Rio Grande Conservancy Dist., 918 P.2d 7, 11 (N.M. 1996) (supporting the proposition that implied-in-fact covenants require mutual assent); Simpson Props., Inc. v. Oexco, Inc., 916 P.2d 853, 858 (Okla. Civ. App. 1996) (noting that implied-in-fact covenants are based on intent and the course of dealing between the parties).

[107]. Danciger Oil & Ref. Co., 154 S.W.2d at 635 (emphasis added); see also Percoff v. Solomon, 67 So. 2d 31, 40-41 (Ala. 1953) (adopting the reasoning of the language quoted in Danciger).

[108]. See Cont'l Potash, Inc. v. Freeport-McMoran, Inc., 858 P.2d 66, 80 (N.M. 1993) (stating that courts look to the intent of the parties when they entered into the agreement). If implied in fact, the implied covenant to market will be unnecessary where the express terms of a lease adequately define the rights and obligations of the parties. Pierce, The Renaissance of Law, supra note 27, at 926. "Also, if the rights and obligations of the parties are not fully defined, but the problem is not an absence of terms but the meaning of the term, then an additional covenant, under an implied-in-fact analysis, would be unnecessary." Id.; cf. supra text accompanying notes 37-39 (commenting that the rights and obligations of the parties should not be increased by an implied covenant when there is an express agreement).

[109]. See Percoff, 67 So. 2d at 40-41 (dispelling the notion that equity may not overthrow a written instrument); Cont'l Potash, Inc., 858 P.2d at 80 (prohibiting an implied covenant from interfering with an express contract); Danciger Oil & Ref. Co., 154 S.W.2d at 635 (reiterating that courts prefer express terms).

[110]. Klein v. Jones, 980 F.2d 521, 523 (8th Cir. 1992); Sword v. Rains, 575 F.2d 810, 813 (10th Cir. 1978); Shelton v. Exxon Corp., 719 F. Supp. 537, 548 (S.D. Tex. 1989), rev'd on other grounds, 921 F.2d 595 (5th Cir. 1991); Eggleson v. McCasland, 98 F. Supp. 693, 695 (E.D. Okla. 1951); Fisher v. Grace Petroleum Corp., 830 P.2d 1380, 1391 (Okla. Civ. App. 1991); TransAm. Natural Gas Corp. v. Finkelstein, 933 S.W.2d 591, 596 (Tex. App.--San Antonio 1996, writ denied); see also Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 567-68 (Tex. 1981) ("Every claim of improper operation by a lessor against a lessee should be tested against the general duty of the lessee to conduct operations as a reasonably prudent operator in order to carry out the purposes of the oil and gas lease.").

[111]. Brewster v. Lanyon Zinc Co., 140 F. 801, 814 (8th Cir. 1905). "Reasonable prudence," of course, is an objective standard. See Irvin, supra note 54, § 18.02[1], at 18-9 (discussing Lanyon Zinc in depth and concluding that the reasonably prudent operator standard is an objective standard). "The prudent operator .... is a hypothetical oil operator who does what he ought to do not what he ought not to do with respect to operations on the leasehold." 5 Williams & Meyers, supra note 105, § 806.3, at 42-42.1.

[112]. Lansdown, Implied Marketing Covenant, supra note 98, at 323.

[113]. Oil and gas marketing necessarily involves economic risk. Many lessees must make marketing decisions quickly and with only sketchy information. See Craig R. Carver, Natural Gas Price Indices: Do They Provide a Sound Basis for Sales and Royalty Payments?, 42 Rocky Mtn. Min.

L. Inst. § 10.06, at 10-29 to -30 (1996) (identifying numerous obstacles a lessee must overcome to successfully market its product); see also Irvin, supra note 54, § 18.05[2] ("Given the wide range of marketing alternatives that are available to many oil and gas lessees in today's market ... a rigid application of the reasonably prudent operator standard in every instance may not be viable or beneficial to either lessor or lessee.").

[114]. See Nordan-Lawton Oil & Gas Corp. of Tex. v. Miller, 272 F. Supp. 125, 137 (W.D. La. 1967) (stating that "operators are not held to such an all-knowing standard that is only revealed by ex post facto judgments"), aff'd, 403 F.2d 949 (5th Cir. 1968); Robbins v. Chevron U.S.A., Inc., 785 P.2d 1010, 1015 (Kan. 1990) ("It is not the place of courts, or lessors, to examine in hindsight the business decisions of a gas producer."); McDowell v. PG & E Res. Co., 658 So. 2d 779, 784 (La. Ct. App. 1995) (urging that, "where the interests of the lessor and the lessee are aligned, as here, the greatest possible leeway should be extended to the lessee in his decisions about marketing gas"); see also 5 Williams & Meyers, supra note 105, § 856.3, at 415 (commenting on the potential result of close judicial scrutiny over decisions lessees make when marketing). According to this treatise:

> There is a great risk that close judicial supervision of the lessee's conduct in selling gas will inhibit his exercise of his best judgment to the detriment of both landowner and operator. Scrutiny of [the] lessee's actions by judges (or worse, juries) in the light of after-acquired knowledge will tend to encourage the operator to take the least hazardous and perhaps the least profitable course of action.

Id. Consequently, in applying the "timing" element of the implied covenant to market, courts have held that a lessee need not go to abnormal extremes to seek a market for its production. See, e.g., Fey v. A.A. Oil Corp., 285 P.2d 578, 587 (Mont. 1955) (holding that a lessee has no implied duty to build a long-distance pipeline to get its gas to market). In applying the "pricing" element of the implied covenant to market, courts have held that a lessee may, under certain conditions, take a price for its gas that is less than market value. E.g., Parker v. TXO Prod. Co., 716 S.W.2d 644, 647 (Tex. App.-- Corpus Christi 1986, no writ); see also supra note 97 (listing cases and other authorities discussing a lessee's obligation to market oil and gas).

[115]. See Kramer, Royalty Interest, supra note 8, at 450 (defining the term "royalty"); see also Altman & Lindberg, supra note 28, at 365 (stating that "[i]t seems unnecessary to support with judicial authority the fact that under most, if not all leases, an oil and gas lessee must bear all of the costs of actual production").

[116]. Energy Oils, Inc. v. Mont. Power Co., 626 F.2d 731, 738 (9th Cir. 1980); Saturn Oil & Gas Co. v. Fed. Power Comm'n, 250 F.2d 61, 64 (10th Cir. 1958); Wall v. United Gas Pub. Serv. Co., 152 So. 561, 563 (La. 1934); Riley v. Meriwether, 780 S.W.2d 919, 923 (Tex. App.--El Paso 1989, writ denied); see also Piney Woods Country Life Sch. v. Shell Oil Co., 539 F. Supp. 957, 971 (S.D. Miss. 1982) (stating that "production ceases once the product is extracted from the earth"), aff'd in part, rev'd in part on other grounds, 726 F.2d 225 (5th Cir. 1984); Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-12 ("The conventional analysis in the oil and gas industry in the latter part of the [twentieth] century had been that 'production' occurs for royalty calculation purposes when oil or gas is captured and held at the wellhead or on the lease ....").

[117]. See TXO Prod. Corp., 716 S.W.2d at 648 (distinguishing production costs from post-production costs); see also Kramer, Royalty Interest, supra note 8, at 450 (noting that a royalty-interest owner does not bear the costs for production or exploration).

[118]. E.g., La Fitte Co. v. United Fuel Gas Co., 284 F.2d 845, 849 (6th Cir. 1960); Ashland Oil & Ref. Co. v. Staats, Inc., 271 F. Supp. 571, 575 (D. Kan. 1967); Scott v. Steinberger, 213 P. 646, 647 (Kan. 1923); Katschor v. Eason Oil Co., 63 P.2d 977, 981 (Okla. 1936); Danciger Oil & Refineries, Inc. v. Hamill Drilling Co., 141 Tex. 153, 171 S.W.2d 321, 322-23 (1943); TXO Prod. Corp., 716 S.W.2d at 648; see also Reed v. Hackworth, 287 S.W.2d 912, 913 (Ky. 1956) (holding that under a market value royalty clause "the lessee need account only for the recited proportion of a sale at the well side, even though he may market the gas elsewhere for a greater sum"); Lawrence Mills & J.C. Willingham, The Law of Oil and Gas § 130, at 189 (1926) ("[T]he lessor is entitled only to his oil or gas or the value thereof at the well and not at some distant market."); George Siefkin, Rights of Lessor and Lessee with Respect to Sale of Gas and As to Gas Royalty Provisions, 4 Inst. on Oil & Gas L. & Tax'n 181, 184 (1953) (noting that royalty cases reflected "the almost universally recognized rule that the lessee's marketing obligation is measured at the well"); supra note 28 (explaining that the intent of the parties is usually consistent with valuation at the well).

[119]. See Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983) ("[I]t must first be determined where [the lease] establishes the point fixing the price (hereinafter referred to as point).... It is well settled that the phrase 'at the well received,' or similar terminology, establishes the 'point' at the mouth of the well."); Atl. Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) (stating 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"); see also supra text accompanying note 56 (noting that royalty clauses can expressly require a lessee to calculate market value at the well).

[120]. La Fitte Co., 284 F.2d at 849; Altman & Lindberg, supra note 28, at 366-67; see also supra text accompanying note 31 (commenting that the definition of royalty is a fractional share of any production).

[121]. La Fitte Co., 284 F.2d at 849; Reed, 287 S.W.2d at 913-14; see also Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989, 992 (Ky. 1935) (holding that the lessee must account for the gross proceeds, as determined at the well, when the lease is silent concerning the place of determination); Lansdown, Marketable Condition Rule, supra note 28, at 671-72 (acknowledging that valuation at the well, absent a contradictory provision in the agreement, is consistent with the parties' intentions); Joseph T. Sneed, Comment, Value of Lessor's Share of Production Where Gas Only Is Produced, 25 Tex. L. Rev. 641, 643-44 (1947) ("Even where the well is not designated as the place where the standard [market price] is applied, the courts will construe the lease so as to make the well the place of application of the standard."). The parties, of course, were free to negotiate a different result. See supra text accompanying notes 56-57 (discussing the possible locations for calculating royalties). If, for instance, the parties negotiated a lease term expressly requiring that the lessee calculate its royalties at a location downstream of the wellhead, the lessee could not pay royalties on the basis of the price or value of its production at the wellhead. See Lansdown, Implied Marketing Covenant, supra note 98, at 328 n.123 (expressing that, "while it is customary that royalties be calculated at the

well, there is nothing that would prevent the parties from agreeing to a royalty clause which provides that royalty is to be calculated at some other point or which prohibits the deduction of some or all of such costs"); see also Old Kent Bank & Trust Co. v. Amoco Prod. Co., 679 F. Supp. 1435, 1445 (W.D. Mich. 1988) (noting that, if the parties used the phrase "at the market," they would not have to share post-production costs).

[122]. Lansdown, Marketable Condition Rule, supra note 28, at 672; Siefkin, supra note 118, at 184.

[123]. The same was also true for "market-value-at-the-well" terms in division orders. See supra text accompanying notes 71-73 (establishing the basic terms for most division orders).

[124]. Lansdown, Implied Marketing Covenant, supra note 98, at 326-27. Some states do not distinguish between "market value" and "proceeds" royalty clauses. In these states, the price that a lessee receives for the sale of oil and gas under an arm's-length contract automatically establishes the market value of the oil or gas. See supra note 55 (identifying case law from multiple states). But even in these states, the price that a lessee receives on the sale of oil or gas at a point downstream of the wellhead arguably should not establish the value of the oil or gas at the wellhead.

[125]. See Hugoton Prod. Co. v. United States, 315 F.2d 868, 871 (Ct. Cl. 1963) (concluding that the comparable sales method--called the market comparison method by the court--demands that "the representative price must be calculated as the weighted average price paid during the year in question for comparable gas at the wellhead under contracts in effect during that year, regardless of the year in which the contracts were entered"); Exxon Corp. v. Middleton, 613 S.W.2d 240, 246 (Tex. 1981) (explaining the comparable sales method); see also Owen L. Anderson, Calculating Royalty: "Costs" Subsequent to Production--"Figures don't lie, but ....", 33 Washburn L.J. 591, 598 (1994) [hereinafter Anderson, Calculating Royalty] ("When there is not an arm's-length sale at the wellhead, the courts first look to other contemporaneous, arm's-length wellhead sales from the same well and then, if there are none, to other comparable sales.").

[126]. See Freeland v. Sun Oil Co., 277 F.2d 154, 159 (5th Cir. 1960) (espousing the rule that "in the analytical process of reconstructing a market value where none otherwise exists with sufficient definiteness, all increase in the ultimate sales value attributable to the expenses incurred in transporting and processing the commodity must be deducted"); Hemler v. Union Producing Co., 40 F. Supp. 824, 832 (W.D. La. 1941) (discussing the workback method for computation of price or value of the product), rev'd on other grounds, 134 F.2d 436 (5th Cir. 1943). The Hemler court stated the following in its discussion:

> [I]f there were no sales of sufficient quantities and prices, that a reasonable man could say that a market existed at the well in the field, ... [i]t has been uniformly held ... that the usual price paid at the nearest point where a market existed, less the additional cost of taking the gas or other product to that market, is the criterion upon which the lessee or purchaser is bound to settle. This ruling is nothing but common sense and simple justice.

Id.; Atl. Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) ("[I]t is commonly understood that 'market price at the well' is often determined by working back from the price at the point of sale, deducting the cost of processing and transportation to the wellhead, to determine 'market value at the wellhead.'"). Numerous other courts have applied the workback method as a proper method to determine market value. E.g., Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984); Scott Paper Co. v. Taslog, Inc., 638 F.2d 790, 799 (5th Cir. Unit B Mar. 1981); Clear Creek Oil & Gas Co. v. Bushmiaer, 264 S.W. 830, 832 (Ark. 1924); Alamitos Land Co. v. Shell Oil Co., 44 P.2d 573, 578 (Cal. 1935); W. Gulf Oil Co. v. Title Ins. & Trust Co., 206 P.2d 643, 647-48 (Cal. Dist. Ct. App. 1949); Cumberland Pipe Line Co. v. Commonwealth ex rel. Ky. State Tax Comm'n, 15 S.W.2d 280, 284 (Ky. 1929); Wall v. United Gas Pub. Serv. Co., 152 So. 561, 564 (La. 1934); Mont. Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978); Katschor v. Eason Oil Co., 63 P.2d 977, 981 (Okla. 1936); see also Barby v. Cabot Corp., 465 F.2d 11, 15 (10th Cir. 1972) (precluding the lessor from collecting royalties calculated on the product after extraction); Tyson v. Surf Oil Co., 196 So. 336, 339-41 (La. 1940) (approving of the trial court's decision to deduct an extraction charge in calculating gas royalties).

[127]. See Piney Woods Country Life Sch., 726 F.2d at 239 (discussing the court's preference for the workback method); Mont. Power Co., 586 P.2d at 303-04 (noting that the workback method is the "least desirable method" for calculating market value at the well); see also Hemler v. Union Producing Co., 134 F.2d 436, 437-38 (5th Cir. 1943) (noting that where the evidence establishes the existence of a market at the wellhead, there is no need to resort to the workback method for calculating the value or price of the production at the wellhead); Amoco Prod. Co. v. First Baptist Church of Pyote, 579 S.W.2d 280, 287 (Tex. Civ. App.--El Paso 1979) (agreeing that the price paid by others is the strongest evidence of the gas's market value), writ ref'd n.r.e., 611 S.W.2d 610 (Tex. 1980) (per curiam), abrogated on other grounds by Amoco Prod. Co. v. Alexander, 622 S.W.2d 563 (Tex. 1981).

[128]. See Conine, Crude Oil Royalty Valuation, supra note 7, § 18.04 [1], 18-23 to -24 ("The added value derived from post-production operations may actually exceed the costs incurred by the lessee, causing wellhead values determined by this workback methodology to overstate the value of the original product and underestimate the contribution made by the expense and risk of voluntary, post-production efforts by the lessee."); Matlock, supra note 97, § 9.04, at 9-20 (echoing that "the netback method has the potential of giving the lessor a windfall over what the lessor would have received had the gas been sold at the wellhead"); Pierce, The Missing Link, supra note 5, at 191 (noting that the workback method "will typically result in an overpayment of royalty because the lessor will be receiving a share of the downstream 'profit' in addition to the wellhead value of the gas").

[129]. See Marla J. Williams et al., Determining the Lessor's Royalty Share of Post-Production Costs: Is the Implied Covenant to Market the Appropriate Analytical Framework?, 41 Rocky Mtn. Min. L. Inst. § 12.02[2], at 12-9 (1995) (noting that courts have historically found the workback method to be "a particularly useful tool for determining market value at the well where no wellhead market exists"). Professor Owen Anderson, a prominent advocate of the first marketable product doctrine, has recognized that prior to the rise of the doctrine, most courts allowed lessees to use the workback method to calculate market value at the wellhead. According to Professor Anderson:

> If there are no comparable sales, which is the case much of the time, the courts allow the parties to calculate wellhead values through use of the "work-back" method. Under this method, also called the "net-back" method, "at-the-well" royalty is

> generally calculated as the downstream/arm's-length sales price (or downstream market value) of gas, minus the lessee's downstream costs and expenses.

Anderson, Calculating Royalty, supra note 125, at 598 (footnotes omitted).

[130]. E.g., Holbein v. Austral Oil Co., 609 F.2d 206, 209 (5th Cir. 1980); Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983); Le Cuno Oil Co. v. Smith, 306 S.W.2d 190, 193 (Tex. Civ. App.--Texarkana 1957, writ ref'd n.r.e.); Rimledge Uranium & Mining Corp. v. Fed. Res. Corp., 374 P.2d 20, 23 (Utah 1962).

[131]. See Sondrol v. Placid Oil Co., 23 F.3d 1341, 1345 (8th Cir. 1994) (holding that the lessor was entitled to one-sixth of proceeds received from the lessee selling to a third party); Old Kent Bank & Trust Co. v. Amoco Prod. Co., 679 F. Supp. 1435, 1438 (W.D. Mich. 1988) (finding that the plaintiff's royalty share was dependent upon the price received by the lessee from a third party purchaser). The implied covenant to market prevented a lessee from structuring a wellhead sale to take unfair advantage of its lessors under a proceeds royalty clause; specifically, where a royalty clause provided that the lessee would pay its royalty owners a proportional share of the price that the lessee received for its production, the implied covenant to market required that the lessee obtain a fair price--the "best price reasonably available"--for the sale of its production. Cabot Corp. v. Brown, 754 S.W.2d 104, 106 (Tex. 1987); see also supra notes 94-97 and accompanying text (examining the phrase "best price reasonably available").

[132]. See Holbein, 609 F.2d at 209 (holding that the lessee properly deducted severance taxes and dehydration costs from royalty payments); Old Kent Bank & Trust Co., 679 F. Supp. at 1445 (declaring that, in determining royalties, the phrase "amount realized at the mouth of the well" equates to proceeds minus expenses); Martin, 571 F. Supp. at 1411 (asserting that net proceeds include certain deductible costs); Matzen v. Hugoton Prod. Co., 321 P.2d 576, 582 (Kan. 1958) (agreeing that reasonable expenses are to be deducted to determine royalties when an agreement contains the phrase "proceeds from the sale of gas, as such"); Le Cuno Oil Co., 306 S.W.2d at 193 (furthering the workback method of calculating royalty payments). In contrast with the term "net proceeds at the well," the terms "gross proceeds at the well" and "proceeds at the well" caused confusion among the courts in oil and gas producing states. Some courts interpreted the terms "gross proceeds" and "proceeds" no differently from the term "net proceeds," allowing a lessee to use the workback method to calculate the price of its production at the well. E.g., Phillips Petroleum Co. v. Johnson, 155 F.2d 185, 188-89 (5th Cir. 1946); Matzen, 321 P.2d at 582; Schroeder v. Terra Energy Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App. 1997); Johnson v. Jernigan, 475 P.2d 396, 399 (Okla. 1970); cf. Frederick R. Parker, Jr., Comment, Costs Deductible by the Lessee in Accounting to Royalty Owners for Production of Oil or Gas, 46 La. L. Rev. 895, 897 (1986) (arguing that the "general current of authority" holds that the term "proceeds" is synonymous with "net proceeds").

Other courts, however, interpreted the terms "gross proceeds" or "proceeds" to preclude a lessee from using the workback method to calculate its royalty payments. See Hanna Oil & Gas Co. v. Taylor, 759 S.W.2d 563, 565 (Ark. 1988) (noting that the term "proceeds," standing alone, means "gross proceeds"); Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989, 991 (Ky. 1935) (commenting that the term "proceeds" refers to the total proceeds from a sale); West v. Alpar Res., Inc., 298 N.W.2d 484, 489 (N.D. 1980) (questioning whether the court should construe "proceeds" as net or gross proceeds); see also Martin, 571 F. Supp. at 1411 (distinguishing between the terms "net proceeds" and "gross proceeds" and noting that "'net proceeds' is typically defined as the sum remaining from gross proceeds of sale after payment of expenses"); Altman & Lindberg, supra note 28, at 375 n.58 ("The term 'gross proceeds' usually implies no deductions of any kind."); cf. Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996) (noting that there is "inherent conflict" in a royalty clause that uses the term "gross proceeds at the well"). But cf. Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1206 (Okla. 1998) (suggesting that the term "gross proceeds" forbids a lessee from deducting post-production costs "only when the point of sale occurs at the leased premises").

[133]. Infra note 193.

[134]. See Pierce, From Extraction to Enduse, supra note 6, at 3-15 to - 16 (discussing the two types of gas royalty clauses).

[135]. See, e.g., Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373 (Tex. 2001) (upholding the idea that under a market royalty clause, a lessee is required only to pay market value, even if it receives more).

[136]. See, e.g., Hurinenko v. Chevron, USA, Inc., 69 F.3d 283, 285 (8th Cir. 1995) (interpreting North Dakota law to allow a lessee to use the workback method to calculate royalties under a "market value at the well" royalty clause); Merritt v. Sw. Elec. Power Co., 499 So. 2d 210, 214 (La. Ct. App. 1986) (permitting use of the workback method for royalty calculation under a "market value at the well" royalty clause); Creson v. Amoco Prod. Co., 10 P.3d 853, 857 (N.M. Ct. App. 2000) (asserting that the workback method is a proper way for a lessee to calculate royalties under a "net proceeds at the well" royalty clause); Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996) (allowing a lessee to use the workback method to calculate royalties under a "market value at the well" royalty clause).

[137]. See Martin v. Glass, 571 F. Supp. 1406, 1415 (N.D. Tex. 1983) (establishing that "post-production costs are properly deductible from royalty").

[138]. See Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.-- Corpus Christi 1986, no writ) ("Costs incurred after production of the gas or minerals are normally proportionately borne by both the operator and the royalty interest owners."); see also Holbein v. Austral Oil Co., 609 F.2d 206, 209 (5th Cir. 1980) (concluding that the lessor must share its proportion of the dehydration costs and severance taxes); Johnson v. Jernigan, 475 P.2d 396, 399 (Okla. 1970) (emphasizing that once gas is made available, the lessor and lessee proportionately share further expenses).

[139]. See Lansdown, Marketable Condition Rule, supra note 28, at 673 (noting that "the issue may best be framed not as whether post-production costs are deductible, but rather the point at which royalty is to be calculated"); David E. Pierce, Developments in Nonregulatory Oil and Gas Law: The Continuing Search for Analytical Foundations, 47 Inst. on Oil & Gas L. & Tax'n § 1.07[4] [a], at 1-41 (1996) [hereinafter Pierce, Developments in Nonregulatory Oil and Gas Law] (stating "the deduction of costs [is] an evidentiary issue, not an entitlement issue"); Tooley & Tooley, supra note 77, § 21.04[2], at 21-9 (claiming that determining the issue as to "whether the royalty clause permits

the lessee to deduct post-production expenses 'from the lessor's royalty' begs the issue because it assumes the royalty owner is entitled to a share of the value of, or the proceeds received for[,] the gas at a point away from the well").

[140]. See AMAX Coal W., Inc. v. Wyo. State Bd. of Equalization, 896 P.2d 1329, 1333 (Wyo. 1995) (agreeing that the workback method "is a recognized appraisal technique"). Even outside the oil and gas context, the workback method is an accepted technique for determining the value of an item at a particular location. See, e.g., Millmaster Int'l, Inc. v. United States, 427 F.2d 811, 815 (C.C.P.A. 1970) (involving imported merchandise); Swenson v. Dep't of Revenue, 553 P.2d 351, 353-54 (Or. 1976) (applying a workback method to timber); R&R Energies v. Mother Earth Indus., Inc., 936 P.2d 1068, 1072 (Utah 1997) (allowing for workback methodologies to apply to geothermal energy); Thunder Basin Coal Co. v. Wyo. State Bd. of Equalization, 896 P.2d 1336, 1339 (Wyo. 1995) (using a workback method for coal production).

[141]. Babin v. First Energy Corp., 693 So. 2d 813, 816 (La. Ct. App. 1997); see also Lansdown, Marketable Condition Rule, supra note 28, at 673 ("In a situation where royalty is to be based on proceeds, and the point of valuation and the point of sale are the same, no deductions are necessary to determine the value to be used in calculating royalty."); Pierce, From Extraction to Enduse, supra note 6, at 3-17 n.61 (stating that "there will be no need to consider costs the lessee incurs downstream from the stated location" if the lessee can determine "the 'proceeds' or 'market value' at the stated location").

[142]. See Pierce, The Missing Link, supra note 5, at 186-87 (explaining the predisposed condition of lessors to seek more value and its implication after gas deregulation).

[143]. Schupbach v. Cont'l Oil Co., 394 P.2d 1, 5-6 (Kan. 1964); Gilmore v. Superior Oil Co., 388 P.2d 602, 605-07 (Kan. 1964); infra text accompanying notes 200-05.

[144]. Infra text accompanying notes 193-308.

[145]. Infra text accompanying notes 200-05, 256-62.

[146]. Maurice H. Merrill, The Law Relating to Covenants Implied in Oil and Gas Leases (1926).

[147]. Merrill, 2d ed., supra note 98, § 221, at 468.

[148]. Id. at 465, 468. Upon reviewing Professor Merrill's writings, Professor David Pierce concluded that Merrill's "ultimate goal was to get the lessor a better bargain than the express terms of the lease would otherwise allow." Pierce, The Renaissance of Law, supra note 27, at 911-12.

[149]. Merrill, 2d ed., supra note 98, § 7, at 27 (emphasis added); see also Martin, supra note 36, at 640 (noting that Professor Merrill "readily admitted the artificial character" of the implied marketing covenant as a device to protect lessors and other royalty owners). Although Merrill advanced his radical theory of implied covenants for the purpose of protecting unsophisticated lessors, he argued

that the implied covenants would apply as a matter of law to all leases, including leases involving sophisticated lessors. Specifically, he stated the following:

> Obviously, the implied covenant doctrine is not rendered inapplicable merely because in a particular instance the factors which justify its imposition as an incident of the relation do not exist. It would impede the administration of justice if the courts were required in each case to embark upon a calculation of the relative knowledge and of the bargaining power of the parties.

Maurice H. Merrill, The Law Relating to Covenants Implied in Oil and Gas Leases § 221, at 227 (2d ed. Supp. 1964).

[150]. Merrill, 2d ed., supra note 98, § 85, at 214-15 (emphasis added). Although Merrill argued that a lessee could not deduct any of its marketing costs, Merrill agreed that if the lessee had to transport its production to a distant downstream market, the lessee could calculate its royalty payments on the basis of the price that it received for its production, "less the reasonable cost of transportation from the lease to the market." Id. § 86, at 219. "The transportation to the distant point is no part of the legitimate operating expense of the lease." Id.

[151]. Id. § 85, at 215 (citing Hamilton v. Empire Gas & Fuel Co., 230 P. 91 (Kan. 1924); Warfield Natural Gas Co. v. Allen, 88 S.W.2d 989 (Ky. 1935); Clark v. Slick Oil Co., 211 P. 496 (Okla. 1922); Harlan v. Cent. Phosphate Co., 62 S.W. 614 (Tenn. Ch. App. 1901)).

[152]. See Altman & Lindberg, supra note 28, at 370 (reluctantly concluding that the case law Merrill cited in support of his interpretation of the implied covenant to market "does not support his premise"); see also Siefkin, supra note 118, at 199 (concluding that the cases Merrill cited in his treatise were "rather old opinions which approach the point collaterally with none of the authoritativeness of even considered dicta"). Interestingly, in a later law review article, Professor Merrill conceded that "[a]ctually the decisions vary." Maurice H. Merrill, Implied Covenants in Oil and Gas Leases, 1959 U. Ill. L.F. 584, 591 (1959).

[153]. See Rogers v. Westerman Farm Co., 29 P.3d 887, 905 (Colo. 2001) (en banc) (implicitly adopting a form of Merrill's approach to the implied covenant to market); see also Gilmore v. Superior Oil Co., 388 P.2d 602, 607 (Kan. 1964) (citing Professor Merrill's work as a sound approach); West v. Apar Res., Inc., 298 N.W.2d 484, 490-91 (N.D. 1980) (reporting on Professor Merrill's approach to the implied covenant to market).

[154]. Marla J. Williams & William D. Watson, The Deductibility of Postproduction Costs in Determining Royalty and Overriding Royalty Under Nonfederal Leases, 48 Inst. on Oil & Gas L. & Tax'n § 6.02[2], at 6-7 (1997).

[155]. Eugene Kuntz, A Treatise on the Law of Oil and Gas (W. H. Anderson Co. 1962).

[156]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351 (emphasis added).

[157]. Id.; see also Lansdown, Marketable Condition Rule, supra note 28, at 680 ("Kuntz's contention consisted of nothing more than an assertion.").

[158]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351; see also supra note 116 and accompanying text (explaining the historical definition of "production" prior to the first marketable product doctrine).

[159]. Indeed, Professor Kuntz expressly rejected Merrill's view that the implied covenant to market required the lessee to bear all of the costs of marketing. As Kuntz explained, the implied covenant may impose on the lessee a duty to seek a market for its production, "but the existence of such [a] duty should not require that the lessee carry the entire expense of delivering gas at a point other than at the well as contemplated." 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 355; see also Lansdown, Marketable Condition Rule, supra note 28, at 680 ("Professor Kuntz ... expressly rejected the concept that the implied covenant to market mandates that the lessor should not bear its proportionate part of post-production costs ....").

[160]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351; see also Pierce, The Royalty Value Theorem, supra note 5, § 6.03[1], at 163 ("Professor Kuntz's analysis is based upon an interpretation of the express term 'production' as opposed to Professor Merrill's use of an implied covenant analysis."); cf. Lansdown, Marketable Condition Rule, supra note 28, at 682 ("Professor Kuntz correctly identifies the issue as one of contractual interpretation, but then gets the interpretation wrong.").

[161]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351.

[162]. Merrill, 2d ed., supra note 98, § 85, at 214-15.

[163]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351.

[164]. See Williams et al., supra note 129, § 12.04, at 12-16 (noting that Professor Kuntz's analysis did not initially find any favor in the courts, "perhaps because 'production' is more typically understood, and more useful a word, when used to refer to the 'act of bringing forth gas from the earth'" (quoting Martin v. Glass, 571 F. Supp. 1406, 1415 (N.D. Tex. 1983))).

[165]. See infra text accompanying notes 256-62 (discussing the Garman decision and its reliance on Kuntz).

[166]. Owen L. Anderson, Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 1, 37 Nat. Resources J. 547 (1997) [hereinafter Anderson, Part 1]; Owen L. Anderson, Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 2, 37 Nat. Resources J. 611 (1997) [hereinafter Anderson, Part 2].

[167]. See Garman v. Conoco, Inc., 886 P.2d 652, 659 (Colo. 1994) (en banc) ("In our view the implied covenant to market obligates the lessee to incur those post-production costs necessary to place gas in a condition acceptable for market."); Sternberger v. Marathon Oil Co., 894 P.2d 788, 795 (Kan. 1995) (claming, "Kansas law holds that transportation costs are borne proportionately by the lessor and the lessee"); Wood v. TXO Prod. Corp., 854 P.2d 880, 882 (Okla. 1992) ("In our view, the implied duty to market means a duty to get the product to the place of sale in marketable form.");

see also infra text accompanying notes 195-283 (discussing the specifics of Garman, Sternberger, and Wood).

[168]. See Anderson, Part 2, supra note 166, at 665-71 (discussing the varying approaches taken by the different states to the first marketable product doctrine).

[169]. Anderson, Part 1, supra note 166, at 552.

[170]. Id. at 572; see also Anderson, Overriding Royalty Interests, supra note 8, at 7 ("[A] pure property-law approach, based upon severance of gas at the wellhead and its conversion to personal property, is not convincing."). Interestingly, although Professor Anderson now rejects "a pure property-law approach" to royalty calculation, he has previously argued that "property principles could be used to address the question of post-wellhead costs." Anderson, Part 1, supra note 166, at 572 (citing Owen L. Anderson, David v. Goliath: Negotiating the 'Lessor's 88" and Representing Lessors and Surface Owners in Oil and Gas Plays, 27B Rocky Mtn. Min. L. Inst. 1029, 1114-16 (1982)). Moreover, Anderson has previously admitted that the property-law approach, which permits the use of the workback method to calculate royalties at the wellhead, represents the majority rule in the United States. See Anderson, Calculating Royalty, supra note 125, at 598 ("If there are no comparable sales, which is the case much of the time, the courts allow the parties to calculate wellhead values through use of the 'work-back' method." (emphasis added)).

[171]. Anderson, Part 2, supra note 166, at 689. Anderson objected that the property-law approach is inconsistent with the ancient history of Roman and English law governing royalties on products such as marble, silver, tin, and ore. See Anderson, Part 1, supra note 166, at 573-83 (analyzing the evolution of "royalty entitlements"). While Anderson's review of this history is interesting, its relevance is marginal. See David E. Pierce, Defining the Role of Industry Custom and Usage in Oil & Gas Litigation, 57 SMU L. Rev. 387, 416-17 n.175 (2004) [hereinafter Pierce, Industry Custom & Usage] ("Other than use of the term 'royalty' to describe the landowner's compensation in the event of production, the oil and gas industry has little connection to the Greeks, Romans, or even the English."). The simple fact remains that up until the development of the first marketable product doctrine, most courts in the United States allowed a lessee to calculate its royalty payments on the basis of the market value or price of its production at the wellhead. Supra notes 118-121 and accompanying text. "Where a jurisdiction has adopted a rule that bases the deductibility of post-production costs on the point that oil and gas is severed from the ground, there does not appear to be any compelling reason to apply the mining law of old Great Britain to overturn that rule." Lansdown, Marketable Condition Rule, supra note 28, at 699.

[172]. Anderson, Part 2, supra note 166, at 683. Anderson's interpretation of the "likely intent" of the parties unrealistically assumes that all lessors have a sophisticated understanding of economic terms. As Lansdown has explained:

> If ... one asks whether an unsophisticated landowner would expect to receive royalty based on: (1) the value of the oil and gas when it reaches the surface; or (2) the value of the oil or gas when it is placed in a 'marketable condition,' an economic concept that no one has attempted to explain with any specificity, a reasonable argument

> could be made that most land owners (assuming they answered honestly) would choose the former.

Lansdown, Marketable Condition Rule, supra note 28, at 699-700.

[173]. Anderson, Part 2, supra note 166, at 611. Although Anderson described his version of the first marketable product doctrine as a contract law analysis, the word "production" does not appear in many gas royalty clauses. See Bruce M. Kramer, Interpreting the Royalty Obligation by Looking at the Express Language: What a Novel Idea?, 35 Tex. Tech L. Rev. 223, 234 (2004) [hereinafter Kramer, Interpreting the Royalty Obligation] ("As for gas royalty clauses, the term produced is not as universally present as in oil royalty clauses.").

[174]. Anderson, Part 2, supra note 166, at 638; accord Anderson, Overriding Royalty Interests, supra note 8, at 7 (explaining that "[t]he words 'production' and its derivatives, such as 'produced,' ... necessarily refer to a product. A 'product' is something that can be used or marketed."); Owen L. Anderson, Rogers, Wellman, and the New Implied Marketplace Covenant, Special Inst. on Private Oil & Gas Royalties pt. 13A, at 13A-9 (Rocky Mtn. Min. L. Found. 2003) [hereinafter Anderson, New Implied Marketplace Covenant] ("When read as a whole, these phrases plainly state that royalty is payable on a marketable or salable product--otherwise there could be no proceeds, market value, or market price ....") (on file with the St. Mary's Law Journal).

[175]. Anderson, Part 2, supra note 166, at 642. Professor Anderson suggested that the "question of when a product first becomes marketable is a question of fact, not law." Id.

[176]. Id. at 613-14; cf. Pierce, Industry Custom & Usage, supra note 171, at 417 n.177 (noting that the "property analysis" that Anderson seeks to eschew is actually a "contract analysis," and that "[t]he terms of the oil and gas lease contract, like most any contract, define the rights of the parties which give rise to their 'property' interests in oil and gas as produced").

[177]. Anderson, Part 2, supra note 166, at 636.

[178]. Id. at 612. Professor Anderson disagreed with those decisions that had distinguished between "market value" and "proceeds," arguing that the result should be the same whether a royalty clause includes "market value" or "proceeds" language. Id. at 613-14; see also id. at 683-84 ("[W]hether royalty is due on 'market value,' 'market price,' 'amount realized,' 'proceeds,' 'net proceeds,' or 'gross proceeds,' ... royalty should be paid on the value of gas as a first-marketable product in the vicinity of the well."). Significantly, Anderson criticized these decisions for failing to consider whether "the parties specifically negotiated for the use of one of these terms in lieu of the others." Id. at 614. However, Anderson did not suggest that the terms "market value" or "proceeds" were ambiguous; and he did not explain the relevance of considering whether the "parties specifically negotiated for the use of one of these terms" if those terms were not ambiguous. Id.

[179]. Id. at 684, 686 (footnote omitted).

[180]. See supra text accompanying notes 170-75 (explaining Anderson's rejection of a "property-law" analysis). Professor Pierce has argued that "Professor Anderson's approach seeks to

substitute a 'reasonable royalty' analysis for the terms of the oil and gas lease." Pierce, The Royalty Value Theorem, supra note 5, § 6.02[3], at 157.

[181]. Anderson, Part 2, supra note 166, at 633-34 (footnote omitted).

[182]. Id. at 636.

[183]. Id. at 640; see also Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-11 (noting that the phrases "at the well" and "at the wellhead" are certainly not mere surplusage).

[184]. See Anderson, Part 2, supra note 166, at 644 (comparing F.O.B. sales in other markets); see also Owen L. Anderson, 2001: A Royalty Odyssey, 53 Inst. on Oil & Gas L. & Tax'n § 4.03, at 4-17 (2002) [hereinafter Anderson, Royalty Odyssey] (noting that "the plain meaning of 'at the well' is 'F.O.B.' the well"); Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-11 (noting that "at the well" language in a royalty clause is "tantamount to F.O.B. the well"). Professor Anderson is incorrect in suggesting that the terms "at the well" or "at the wellhead" are akin to F.O.B. shipping terms in a commercial contract. In a commercial contract for the sale of goods, the term "F.O.B." means that title to the goods passes to the buyer at the specified shipping point--for example, if a contract contemplates that a manufacturer will sell 50,000 widgets to a distributor "F.O.B. Cushing, Oklahoma," the distributor will receive title to the widgets in Cushing. See, e.g., Future Tech Int'l, Inc. v. Tae Il Media, Ltd., 944 F. Supp. 1538, 1549 (S.D. Fla. 1996) (noting that lawful title passed upon delivery at the specified shipping point); Miami Paper Corp. v. Magnetics, Inc., 591 F. Supp. 52, 55 n.2 (S.D. Ohio 1984) (explaining that the term F.O.B. determines when title and risk of loss pass). By contrast, under a royalty clause that calls for the payment of monetary royalties, the lessor never receives title to the oil or gas production--either at the wellhead or downstream of the wellhead. See supra text accompanying note 58 (explaining that the lessee receives all title to produced oil and gas under a monetary royalty clause).

[185]. See Anderson, Part 2, supra note 166, at 664 ("F.O.B. speaks only to the location of goods, not their condition."). Contrary to Professor Anderson's claim, the term "F.O.B." speaks not only to the location of goods, but also to their condition. Under F.O.B. shipping terms, the buyer agrees to accept title to the goods in their condition at the specified shipping point or F.O.B. location, and the buyer assumes all risk of loss (and, for that matter, all benefit of gain) after it acquires title to the goods. See Jacobson v. Neuensorger Korbwaren-Industrie Friedrich Kretz, K.-G., 109 So. 2d 612, 614 (Fla. Dist. Ct. App. 1959) (noting that the term "F.O.B. Hamburg" meant that title to the goods passed to the buyer in Hamburg and "[f]rom that point, and during the balance of the journey, the risk of loss was on the purchaser"). Consequently, if a third party shipper damages the goods after the buyer acquires title to them, the buyer must still pay the seller the price or value of the goods at the specified F.O.B. location--in other words, the price or value of the goods in their pre-damaged condition at the specified location. See U.C.C. § 2-509(1)(a) (2000) (allocating the risk of loss to the buyer when a carrier is used); cf. United States v. Carl M. Geupal Const. Co., 423 F.2d 818, 821 (7th Cir. 1970) (holding that the term "F.O.B. jobsite" entitled the supplier to be paid for the raw materials as measured by the cubic yard at the jobsite, and not as measured by the enhanced value of the assembled materials at the final destination point after assembly at the jobsite).

If, as Anderson claims, the term "at the well" is really akin to the term "F.O.B. at the wellhead," then the buyer (i.e., the lessee) should have to pay the seller (i.e., the lessor) a royalty based on the price or value of the goods (i.e., the production) in their condition at the specified F.O.B. location--the wellhead. See Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 892-93 (Mich. Ct. App. 1997) (arguing, in an oil and gas royalty context, the difference in risk allocation under shipment F.O.B. and shipment at the seller's risk and expense). In the words of Schroeder:

> As with any other sale of goods, there is one price for goods sold f.o.b. the seller's place of production, where the buyer must pay freight costs and accept the risk of loss during transportation, and a second, higher price if the goods are sold on the understanding that the seller, at its own risk and expense, will deliver them to the buyer at the buyer's place of use.

Id. (emphasis added).

[186]. Anderson, Part 2, supra note 166, at 640-41 (emphasis added) (citation omitted). Professor Anderson reasoned that transportation costs would also "include compression costs incurred to deliver gas into extensive gathering lines or transmission pipelines." Id. at 691.

[187]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351. Anderson apparently believes that Kuntz would have agreed that a lessee could deduct transportation costs in calculating royalties on oil or gas that the lessee sells downstream of the wellhead. See Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-15 (discussing Kuntz's opinion, as reflected in a conversation Kuntz had with Anderson prior to Kuntz's death). Kuntz's writings, however, suggest differently. See 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351 (arguing that only after a marketable product has been obtained are "further costs in improving or transporting such product ... shared by the lessor and lessee" (emphasis added)).

[188]. Anderson, Royalty Odyssey, supra note 184, § 4.01, at 4-2.

[189]. See Anderson, Part 2, supra note 166, at 637 ("[T]he point where a marketable product is first obtained is the logical point ... where the primary objective of the lease contract is achieved, and therefore is the logical point for the calculation of royalty."); see also Owen L. Anderson, Royalty Valuation: Calculating Freight in a Marketable-Product Jurisdiction, 20 Energy & Min. L. Inst. § 10.02[1], at 337 (2000) (formerly named E. Min. L. Inst.) [hereinafter Anderson, Calculating Freight] (reaffirming his view that "lessees should not have to share proportionately with the lessor in the event that gas is first sold downstream of the first market in states that adopt a marketable-product approach").

[190]. See Anderson, Part 2, supra note 166, at 691 ("Transportation costs, apart from delivery of gas in the vicinity of the well, should be proportionately charged to lessors through royalty accounting, because royalty should not be payable on transportation.").

[191]. See Anderson, Part 1, supra note 166, at 549 (agreeing that, "[i]n the absence of an express lease provision to the contrary, lessees should be allowed to deduct 'post-production' costs when calculating royalty"). Although Professor Anderson stated that lessees should be allowed to deduct post-production costs, Anderson denied his analysis would require that lessees use a workback

method for calculating royalty payments. Specifically, Anderson claimed: "Once [a] first-marketable product has been obtained, its value is readily determinable because third parties are buying the production in arm's [-]length equivalent transactions. There is no need for work-back calculations ...." Anderson, Part 2, supra note 166, at 682.

Despite Professor Anderson's assurances, his version of first marketable product doctrine does not necessarily eliminate the need for a workback calculation. Anderson himself concluded that lessees could charge transportation costs to their lessors "through royalty accounting." Anderson, Part 2, supra note 166, at 691. Thus, even Anderson would agree that, at a minimum, lessees may still have to use a form of the workback method to take transportation costs into account in calculating royalties. See Anderson, Calculating Freight, supra note 189, § 10.02[2], at 341 (discussing "work-back" calculations under a "true first-marketable-product royalty valuation approach"). Moreover, Anderson's version of the first marketable product rule requires only the putative existence of a market, not any actual contracts or sales. For instance, Anderson recognized that sweet, dry gas normally is marketable at the wellhead. Anderson, Part 2, supra note 166, at 634. If, however, the lessee chooses not to market sweet, dry gas at the wellhead and instead sells it to a third party purchaser downstream of the wellhead, the lessee may have to use a workback method, in the absence of any actual sales at the wellhead, to determine the value of the gas at the wellhead where it was first marketable. See id. at 653-54 (agreeing with those cases that permit a lessee to calculate royalties by deducting gasoline extraction costs from the downstream value of wet gas because "wet gas is probably a marketable product").

[192]. Anderson, Royalty Odyssey, supra note 184, § 4.01, at 4-1. Anderson observed that his views "do not appear to have been expressly adopted by any courts or justices, except reversed justices of the Colorado Court of Appeals and one dissenting justice on the Oklahoma Supreme Court." Id. at 4-2.

[193]. Based upon existing federal and state court precedent, the states that continue to adhere to this general rule include the following: (1) Texas --Heritage Resources, Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996); Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 135 (Tex. 1996); (2) Louisiana --Freeland v. Sun Oil Co., 277 F.2d 154, 159 (5th Cir. 1960); Wall v. United Gas Public Service Co., 152 So. 561, 564 (La. 1934); Merritt v. Southwestern Electric Power Co., 499 So. 2d 210, 213 (La. Ct. App. 1986); (3) Montana --Montana Power Co. v. Kravik, 586 P.2d 298, 303 (Mont. 1978); (4) California --Alamitos Land Co. v. Shell Oil Co., 44 P.2d 573, 576 (Cal. 1935); Atlantic Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989); (5) Mississippi --Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984); (6) Kentucky --Reed v. Hackworth, 287 S.W.2d 912, 913 (Ky. 1956); (7) North Dakota --Hurinenko v. Chevron, USA, Inc., 69 F.3d 283, 285 (8th Cir. 1995); Koch Oil Co. v. Hanson, 536 N.W.2d 702, 707 (N.D. 1995); and (8) New Mexico --Elliott Industries Ltd. Partnership v. BP American Production Co., 407 F.3d 1091, 1113- 14 (10th Cir. 2005); Creson v. Amoco Production Co., 10 P.3d 853, 857 (N.M. Ct. App. 2000). But see San Juan 1990-A, L.P. v. El Paso Prod. Co., No. D-0101-CV-9501997, at 9 (N.M. Dist. Ct. Nov. 6, 2000) (mem.) (concluding that, notwithstanding the opinion in Creson, the New Mexico Supreme Court is likely to "adopt the marketable condition rule under an implied covenant to market" when directly presented with the issue) (on file with the St. Mary's Law Journal). Additionally, Michigan has adopted the general rule, at least for leases dated prior to March 28, 2000. Compare Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App.

1997) (explaining that the general rule exemplifies the intent of the parties), with Mich. Comp. Laws Serv. §324.61503b(1) (LexisNexis Supp. 2005) ("A person who enters into a gas lease as a lessee after March 28, 2000 shall not deduct from the lessor's royalty any portion of postproduction costs unless the lease explicitly allows for the deduction of postproduction costs.").

Although no appellate court in Alabama has specifically addressed the issue in a royalty context, some case law suggests that Alabama likewise would adopt the general rule. See Scott Paper Co. v. Taslog, Inc., 638 F.2d 790, 799 (5th Cir. Unit B Mar. 1981) (applying Alabama law to approve the use of a workback method for calculating the fair market value of hydrogen sulfide at the wellhead); State v. Phillips Petroleum Co., 638 So. 2d 893, 895 (Ala. 1994) (approving the use of a workback method to calculate the fair market value of gas at the wellhead for privilege tax purposes).

[194]. See infra text accompanying notes 195-308 (analyzing the first marketable product doctrine in Kansas, Oklahoma, Colorado, and West Virginia). Three states--Wyoming, Nevada, and Michigan--have enacted statutes that arguably codify versions of the first marketable product rule. See Mich. Comp. Laws Serv. §324.61503b(1) (LexisNexis Supp. 2005) (permitting lessees to deduct post-production costs only if the lease specifically allows such deductions); Nev. Rev. Stat. §§ 522.115(1)(a), (3)(d) (2003) (prohibiting a lessee from deducting production costs, but defining "costs of production" as not including costs incurred to transport a product "to the market" or "the processing of gas in a processing plant"); Wyo. Stat. Ann. § 30-5-304(vi) (2003) (defining "costs of production" and stating that the costs do not "include 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"). But see supra note 193 (observing that the Michigan statute applies only to leases dated after March 28, 2000). The statutes in these states are subject to different rules of interpretation than the common law versions of the first marketable product rule. See, e.g., Wold v. Hunt Oil Co., 52 F. Supp. 2d 1330, 1336 (D. Wyo. 1999) (disagreeing that Wyoming has codified the first marketable product rule, and noting that the Wyoming statute "must be read alone and without reference to the common law as it may have evolved in other states such as Colorado"). Nonetheless, the flaws in the first marketable product doctrine are just as apparent in the states with codified rules of interpretation as they are in the states that have adopted common law versions of the doctrine. Dante L. Zarlengo, An Analysis of State Oil and Gas Royalty Payment Laws: The Political Process Crosses with the Common Law, Special Inst. on Private Oil & Gas Royalties, pt. 12, at 12-13 to -14 (Rocky Mtn. Min. L. Found. 2003) (on file with the St. Mary's Law Journal).

Although no appellate court in Illinois has specifically addressed the issue in a royalty context, some case law suggests that Illinois would adopt the first marketable product doctrine. See Marlin Energy, Inc. v. Sorling, Northrup, Hanna, Cullen & Cochran, Ltd., 243 F. Supp. 2d 835, 842 (C.D. Ill. 2003) (adopting the first marketable product rule for use in interpreting the word "production" under the Illinois Oil and Gas Lien Act).

Some commentators have argued that Arkansas and North Dakota "can also be counted among those that follow the marketability approach." Robert S. Raynes, Jr., Comment, A Royalty Pain in the Gas: What Costs May Be Properly Deducted from a Gas Royalty Interest?, 98 W. Va. L. Rev. 1199, 1210 (1996) (citing Garman v. Conoco, Inc, 886 P.2d 652, 658 (Colo. 1994) (en banc), in the discussion of his proposition). Garman cites Hanna Oil & Casualty Co. v. Taylor, 759 S.W.2d 563 (Ark. 1988), as well as West v. Alpar Resources, Inc., 298 N.W.2d 484 (N.D. 1980), in its discussion of Arkansas and North Dakota law. Garman, 886 P.2d at 658. The decisions in Hanna Oil and West, however, involve "gross proceeds" or "proceeds" leases. See Hanna Oil, 759 S.W.2d at 564 (considering a proceeds royalty clause); West, 298 N.W.2d at 486 (evaluating a proceeds lease). Even in jurisdictions that have rejected the first marketable product doctrine, a "gross proceeds" lease may forbid a lessee from using a workback method to calculate its royalty payments. See Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996) (noting that the term "gross proceeds" is unclear); see also supra note 132 (observing that some courts interpret the term "gross proceeds" to preclude a workback methodology). North Dakota, in fact, has arguably rejected the first marketable product doctrine. See Hurinenko v. Chevron, USA, Inc., 69 F.3d 283, 285 (8th Cir. 1995) (applying North Dakota law and distinguishing West v. Alpar Resources, Inc.); cf. Bice v. Petro-Hunt, L.L.C., 681 N.W.2d 74, 80 (N.D. 2004) (suggesting that whether the implied covenant to market would require lessees to produce a first marketable product is "unsettled law" in North Dakota). Arkansas has not squarely faced the question. Cf. Poitevent, supra note 60, at 747 ("[T]he Arkansas courts appear reluctant to choose sides in the developing schism. Oklahoma is doing its best to pull Arkansas onto the marketable product side by citing its decisions. However, it appears that Arkansas is still reluctant to commit." (footnote omitted)).

The federal government has enacted regulations that arguably codify a version of the first marketable product rule where the lessee has taken a lease on federal lands. See, e.g., 30 C.F.R. § 206.106 (2002) ("You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government."); 30 C.F.R. § 206.152(i) (2002) ("The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government."); see also Thomas F. Reese & Drake D. Hill, Wyoming's Powder River Basin: A Study in Federal Royalty Valuation, 4 Wyo. L. Rev. 629, 630 (2004) (discussing royalty calculation issues on production from leases on federal lands).

[195]. See, e.g., Matzen v. Hugoton Prod. Co., 321 P.2d 576, 581 (Kan. 1958) (holding that the duty to market "did not extend to providing a gathering system to transport and process the gas off the leases ... in order to obtain a market at which the gas might be sold"); Molter v. Lewis, 134 P.2d 404, 407 (Kan. 1943) (noting that the duty to market "is a matter of reasonable diligence and does not touch the question of expense"); Scott v. Steinberger, 213 P. 646, 647 (Kan. 1923) (explaining that royalty should be based on the value at the well rather than at some "distant market"); cf. Johnson v. Kan. Natural Gas Co., 135 P. 589, 592 (Kan. 1913) (rejecting the defendant's claim that the costs of a pipeline rental are within reasonable expenses to market).

[196]. 321 P.2d 576 (Kan. 1958).

[197]. Matzen v. Hugoton Prod. Co., 321 P.2d 576, 582 (Kan. 1958) (emphasis added).

[198]. Molter, 134 P.2d at 407 (quoting Lawrence Mills & J.C. Willingham, The Law of Oil and Gas § 130, at 189 (1926)).

[199]. 394 P.2d 1 (Kan. 1964).

[200]. 388 P.2d 602 (Kan. 1964).

[201]. Schupbach v. Cont'l Oil Co., 394 P.2d 1, 2 (Kan. 1964); Gilmore v. Superior Oil Co., 388 P.2d 602, 605 (Kan. 1964).

[202]. Schupbach, 394 P.2d at 3; Gilmore, 388 P.2d at 604.

[203]. Schupbach, 394 P.2d at 4; Gilmore, 388 P.2d at 604-05. A lessee must frequently compress gas (i.e., apply pressure to the gas stream) to allow it to enter and move through a pipeline. Thus, compression costs are those costs that a lessee incurs "to increase pressure necessary to allow natural gas to move within a gathering or transportation system to the point of first sale." Stewart & Maron, supra note 19, at 662.

[204]. Compare Gilmore, 388 P.2d at 607 (finding that the payment of compression costs is part of a lessee's duty to prepare the gas for market, and that a lessee cannot deduct such costs), with Schupbach, 394 P.2d at 5 (finding Gilmore controlling precedent, and holding that the trial court erred in holding that the lessee was entitled to deduct the costs of compression). Justice Fontron, on the other hand, filed a concurring opinion in Schupbach acknowledging that Gilmore was binding precedent, but noting that he found it "extremely difficult to accept the rationale of Gilmore." Schupbach, 394 P.2d at 7 (Fontron, J., concurring). He explained:

> It offends my sense of logic to say that the market value of gas at the mouth of the well is the price for which the gas is ultimately sold after having been so processed that it has become marketable. I would consider that market value of gas at the well would be that amount for which it could be sold, after deducting such reasonable expense as was required to render it saleable.

Id.

[205]. Gilmore, 388 P.2d at 607 (citing Maurice H. Merrill, The Law Relating to Covenants Implied in Oil and Gas Leases § 85, at 61 (Supp. 1959)). Gilmore distinguished Matzen on the basis that the parties in Matzen had stipulated to the deduction of gathering costs. Gilmore, 388 P.2d at 605. In truth, the deductibility of gathering costs was a hotly disputed issue in Matzen. See Matzen v. Hugoton Prod. Co., 321 P.2d 576, 583 (Kan. 1958) (considering which expenses could be properly deducted); see also R. Kevin Redwine & Steven G. Heinen, Deductibility of Natural Gas Compression Costs in Light of Fox Wood III v. TXO Production Co., 29 Tulsa L.J. 677, 687 (1994) ("The Gilmore court attempted to distinguish Matzen but did so unconvincingly."); Williams et al., supra note 129, § 12.06[1][c], at 12-38 to -39 (noting that Gilmore's attempt to distinguish Matzen was based on "dubious" grounds). Professor Summers, whom the court in Gilmore cited in support of its decision, argued that Gilmore was "contrary to the majority rule and lays upon the lessee a financial burden not necessarily part of the duty to market." 3A W.L. Summers, The Law of Oil and Gas § 589, at 22 n.18 (2d ed. Supp. 2004); see also Piney Woods Country Life Sch. v. Shell Oil Co., 539 F. Supp. 957, 973 (S.D. Miss. 1982) (observing that Gilmore and Schupbach were "in conflict with prior authority"), aff'd in part, rev'd in part on other grounds, 726 F.2d 225 (5th Cir. 1984).

[206]. See Lowe, Interpreting the Royalty Obligation, supra note 33, at 6- 13 n.52 (noting the common perception at the time that Gilmore and Schupbach were distinguishable).

[207]. 271 F. Supp. 571 (D. Kan. 1967).

[208]. Ashland Oil & Ref. Co. v. Staats, Inc., 271 F. Supp. 571, 575 (D. Kan. 1967).

[209]. Id. at 574 (emphasis added). The court commented:

> We will not so enlarge the lessee's duty to market production so as to require it to devote a long and costly gathering system to transport gas to the nearest commercial market. The two state cases [Gilmore and Schupbach] do not support such a holding and nowhere have we found the lessee's duty to market thus extended.

Id. at 575.

[210]. See Kramer, Interpreting the Royalty Obligation, supra note 173, at 256 (explaining that Gilmore and Schupbach were the progenitors of more recent first marketable product cases); see also David E. Pierce, Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market, 48 Rocky Mtn. Min. L. Inst. § 10.05[1], at 10-18 n.60 (2002) [hereinafter Pierce, Exploring the Jurisprudential Underpinnings] (identifying Gilmore as "perhaps the first statement of the marketable product rule").

[211]. 894 P.2d 788 (Kan. 1995).

[212]. Sternberger v. Marathon Oil Co., 894 P.2d 788, 797 (Kan. 1995).

[213]. Id. at 796-97.

[214]. Id. at 799-800. The court in Sternberger did not attempt to define the term "marketable," although the court ultimately concluded that the lessee's gas production was "marketable at the well." Id. at 800. Similarly, the court did not attempt to define the term "product."

[215]. See id. at 799 (discussing a lessee's duties to make the product marketable and to market it).

[216]. Id. at 800.

[217]. Sternberger, 894 P.2d at 800.

[218]. Id. (emphasis added); see Lansdown, Marketable Condition Rule, supra note 28, at 684 ("[T]he Sternberger opinion alluded to the fact that the absence of an immediate purchaser did not render the gas unmarketable, leaving entirely open the question of what the term 'marketable' actually means."); Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07 [4][b], at 1-47 ("The court's holding supports the concept that one can have a marketable product without having anyone willing to buy it at a particular location."). But cf. Voshell v. Indian Territory Illuminating Oil Co., 19 P.2d 456, 458 (Kan. 1933) ("[A] market price presupposes the existence of a market. But there was no market.").

[219]. Sternberger, 894 P.2d at 800. Sternberger placed the burden on the lessor to prove that the lessee breached the implied marketing covenant, but it placed the burden on the lessee to prove the reasonableness of any costs that the lessee incurred beyond the point where the lessee first achieved a marketable product. Id. In a subsequent case, the Kansas Supreme Court confirmed that the lessor

bears the burden of proving that the lessee has breached its implied covenant to market. Smith v. Amoco Prod. Co., 31 P.3d 255, 274 (Kan. 2001); see also infra text accompanying notes 220-25 (explaining the lessor's burden of proof).

[220]. 31 P.3d 255 (Kan. 2001).

[221]. Smith v. Amoco Prod. Co., 31 P.3d 255, 258 (Kan. 2001).

[222]. Id. at 263.

[223]. Id. at 258.

[224]. Id. at 268 ("We choose to join Oklahoma, Texas, and Montana in holding that the covenants are implied in fact."). The fact that Smith seemingly ignores Sternberger is significant. Although the Smith court held that the implied covenant to market is implied in fact, Professor Pierce has observed that Sternberger is "not totally consistent with an implied-in-fact approach." Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[3], at 10-28.

[225]. Smith, 31 P.3d at 273.

[226]. Sternberger v. Marathon Oil Co., 894 P.2d 788, 800 (Kan. 1995). While conceding that Kansas has not adopted his version of the first marketable product doctrine, Professor Anderson has stated that his views are "similar to Kansas case law regarding so-called post-wellhead costs." Anderson, Royalty Odyssey, supra note 184, § 4.01, at 4-2; see also Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-3 (stating that his views "are similar to those of the Kansas Supreme Court").

[227]. See Smith, 31 P.3d at 268 (explaining that the implied covenant to market is implied in fact).

[228]. See, e.g., Harding v. Cameron, 220 F. Supp. 466, 471 (W.D. Okla. 1963) (stating that the rule in Oklahoma allows the lessee to deduct compression costs); Johnson v. Jernigan, 475 P.2d 396, 398 (Okla. 1970) (following earlier decisions allowing the workback method); Cimarron Utils. Co. v. Safranko, 101 P.2d 258, 260 (Okla. 1940) (analyzing the rule in Oklahoma when no market price exists at the well); Katschor v. Eason Oil Co., 63 P.2d 977, 981 (Okla. 1936) (determining that landowners were entitled to royalty based on the actual value as calculated at the well); see also In re Martin, 321 P.2d 659, 665 (Okla. 1956) (noting that the lessee should calculate its royalties "at the wellhead"). But cf. Clark v. Slick Oil Co., 211 P. 496, 501 (Okla. 1922) (holding that the lessor under an in-kind oil royalty clause owed no duty to furnish storage tanks to receive the oil, but instead that the lessee owed a duty to prepare the royalty oil "for market so that it would be received by the pipe line").

[229]. 101 P.2d 258 (Okla. 1940).

[230]. Cimarron Utils. Co. v. Safranko, 101 P.2d 258, 260 (Okla. 1940).

[231]. See id. (opining that the rule in several other states was the best method).

[232]. Redwine & Heinen, supra note 205, at 693; cf. Williams & Watson, supra note 154, § 6.03[12][e], at 6-46 n.120 ("[P]rior to Wood, most commentators had placed Oklahoma among the states adhering to the rule that the lessor shared in postproduction costs.").

[233]. 854 P.2d 880 (Okla. 1992).

[234]. Wood v. TXO Prod. Corp., 854 P.2d 880, 880 (Okla. 1992).

[235]. Id. at 881. But cf. Roberts Ranch Co. v. Exxon Corp., 43 F. Supp. 2d 1252, 1257 (W.D. Okla. 1997) (citing Wood but incorrectly suggesting that a lessee may have to bear all of the transportation costs necessary to deliver its production to a commercial market, stating that "in the absence of an express contractual provision to the contrary, the lessee bears the costs associated with getting the gas to the place of sale in a marketable form" (emphasis added)).

[236]. Wood, 854 P.2d at 882 (emphasis added). Significantly, the court in Wood did not discuss or even cite its decision in Safranko. See Redwine & Heinen, supra note 205, at 698 ("[T]he Wood decision effectively ignores prior Oklahoma precedent as to the deductibility of compression and other post-production costs."); Williams & Watson, supra note 154, § 6.03[12] [e], at 6-45 ("Remarkably, Wood directly contradicts, without claiming to overrule, Oklahoma precedent developed over a period of thirty-four years on the (until then, separate) issues of the implied covenant to market and the allocation of postproduction expenses.").

[237]. Wood, 854 P.2d at 882; see also Anderson, Part 2, supra note 166, at 666 (noting that, because Wood did not make a factual inquiry into whether the gas was marketable at the wellhead, it essentially held that compression was "necessary to make gas marketable as a matter of law" (emphasis added)). The court in Wood distinguished compression costs from transportation costs without specifying whether the lessee compressed the gas to remove it from the ground or get it into a pipeline. In the former instance, compression costs are costs of production. Anderson, Part 2, supra note 166, at 668 n.247. But in the latter instance, compression costs are simply a form of transportation costs: the lessee must "compress" the gas to get it into the pipeline that transports the gas to market. See id. at 669 (recognizing that transportation costs may include the compression costs that a lessee incurs to deliver gas into gathering lines or transmission pipelines); see also Hanna Oil & Gas Co. v. Taylor, 759 S.W.2d 563, 566 (Ark. 1988) (Hays, J., dissenting) (stating that "[c]ompression costs are comparable to the costs of trucking production to a distant pipeline since both are merely logistical methods by which the gap between production and pipeline is transcended, regardless of whether such gap is measured in inches or miles"); Poitevent, supra note 60, at 761 ("Compression ... has no chemical or other effect upon production. Rather, as lessees have argued, compression to move production from the lease is a type of transportation cost that should be shared between the lessor and lessee."); Redwine & Heinen, supra note 205, at 691 ("In fact, it is difficult to distinguish compression costs from other types of transportation costs. Compression merely acts to 'push' the gas into a high pressure pipeline, and is not conceptually different from trucking the gas from the well to the purchaser's pipeline."); Tooley & Tooley, supra note 77, § 21.05[3][b], at 21-25 (recognizing that "[t]ypical compression serves a transportation function").

[238]. Wood, 854 P.2d at 882-83. Chief Justice Opala, dissenting with three other justices, argued that the court had rejected the prevailing rule of royalty calculation in favor of the strongly criticized Kansas rule of Gilmore and Schupbach. Id. at 885-86 (Opala, C.J., dissenting). He noted: "Because the price of gas is determined at the well, the lessee's implied duty to market the gas does not include the burden of expenses incurred after the gas passes through the wellhead, or post-production costs." Id. at 884-85. Chief Justice Opala concluded that "[g]as compression necessary to effect delivery of gas into the pipeline is a post-production cost which should be borne equally by the lessor and lessee." Id. at 888.

[239]. 903 P.2d 259 (Okla. 1994).

[240]. TXO Prod. Corp. v. State ex rel. Comm'rs of the Land Office, 903 P.2d 259, 260-61 (Okla. 1994).

[241]. Id. at 262; see also Sternberger v. Marathon Oil Co., 894 P.2d 788, 804 (Kan. 1995) (interpreting Wood and TXO to hold that "[c]ompression and other expenses necessary to make the product marketable are not deductible, but transportation costs are deductible where the sale occurs off the lease premises"). However, this language from the decision in TXO was dicta. See Williams & Watson, supra note 154, § 6.03[12][f], at 6-47 (implying that the TXO court stated dicta about the implied covenant to market). The state land office was a lessor under a lease that allowed it to elect between two royalty options. Id. Of these two options, the land office chose to receive royalties on the basis of the market value of the gas production "without cost into pipelines." Id. The court, even before analyzing its decision in Wood, noted that the term "without cost into pipelines" would prevent the lessee from deducting compression, dehydration, and gathering costs, which are expenses that the lessee would incur before delivering its production into the pipeline. See supra text accompanying notes 56-57 (noting that the lessor and lessee are free to negotiate lease terms which would require the lessee to calculate royalties at a point downstream of the wellhead).

[242]. TXO, 903 P.2d at 262-63. The TXO court made no attempt to determine whether the gas production at issue was marketable at the well. It simply assumed that dehydration and gathering were necessary to produce a marketable product. See Anderson, Part 2, supra note 166, at 668 (noting that after Wood and TXO, compression, dehydration, and gathering costs were "not deductible essentially as a matter of law"); Williams & Watson, supra note 154, § 6.03[12][f], at 6-48 (noting that the court in TXO offered "an unfortunate and totally gratuitous discussion suggesting that dehydration and gathering are per se marketing costs"); see also Rogers v. Westerman Farm Co., 29 P.3d 887, 905-06 n.21 (Colo. 2001) (en banc) (criticizing Wood for "seemingly" holding that dehydration and gathering costs "are not deductible as a matter of law").

[243]. See Williams & Watson, supra note 154, § 6.03[12][f], at 6-48 (arguing that "the notion of per se marketing costs without regard to the market itself goes far beyond anything Professor Merrill had in mind and far beyond any of the other cases purporting to employ his analysis"); see also Anderson, Part 2, supra note 166, at 666-69 (concluding that the Oklahoma rulings were "wide of the mark"); Redwine & Heinen, supra note 205, at 700-01 (criticizing the court's logic).

[244]. 954 P.2d 1203 (Okla. 1998).

[245]. Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1205 (Okla. 1998); see also Anderson, Part 2, supra note 166, at 693 (noting that the supreme court in Mittelstaedt "wisely retreated from the impression left in its prior opinions that marketability is to be determined as a matter of law").

[246]. Mittelstaedt, 954 P.2d at 1208 ("The lessee has a duty to provide a marketable product ...."). The royalty clause at issue in Mittelstaedt required the lessee to pay the lessor "3/16 of the gross proceeds received for the gas sold." Id. at 1204-05 (emphasis added) (quoting the certified question from the Sixth Circuit, which quoted from the lease at issue). Although the supreme court observed that "[t]he term 'gross proceeds' usually implies no deductions of any kind," the court declined to resolve the royalty dispute in that case solely on the basis of the meaning of the term "gross proceeds." Id. at 1206 (quoting Altman & Lindberg, supra note 28, at 375); see also supra note 132 (comparing analyses of the terms "net proceeds" and "gross proceeds"). Because the lessee in Mittelstaedt had sold its production downstream of the wellhead, the court concluded that the term "gross proceeds" did not in itself unambiguously forbid the lessee from deducting post-production costs. Mittelstaedt, 954 P.2d at 1206. According to the court, "'gross proceeds' does indicate an amount without deduction from, or charge against, the royalty interest, but only when the point of sale occurs at the leased premises." Id. (emphasis added).

[247]. Mittelstaedt, 954 P.2d at 1205. The Oklahoma Supreme Court in Mittelstaedt used the term "post-production costs" to refer to those expenses that a lessee incurs after extracting oil, gas, and other minerals from the ground; in contrast to Professor Anderson, who defined the term "post-production costs" to refer to those expenses that a lessee incurs after acquiring a first marketable product. Compare id. at 1208 (discussing post-production costs in terms of "costs incurred after severance at the wellhead"), with supra text accompanying note 191 (asserting Professor Anderson's view that the lessee can deduct costs associated with activities after acquiring a first marketable product). However, where Professor Anderson would agree that a lessor historically must bear a proportionate share of any and all post-production costs (at least under his definition of the term), the court in Mittelstaedt reasoned that a lessor, depending on the circumstances, may or may not have to bear a proportionate share of post-production costs. As the Mittelstaedt court stated:

> Generally, costs have been construed as either production costs which are never allocated, or post-production costs, which may or may not be allocated, based upon the nature of the cost as it relates to the duties of the lessee created by the express language of the lease, the implied covenants, and custom and usage in the industry.

Mittelstaedt, 954 P.2d at 1209 (emphasis added). The court cited no authority for its conclusion that post-production costs "may or may not be allocated." Id.

[248]. See id. at 1208 (concluding that a lessor must pay only if the lessee can meet its burden); see also Purcell v. Santa Fe Minerals, Inc., 961 P.2d 188, 189 (Okla. 1998) (affirming the lessee's burden under Mittelstaedt). The supreme court in Mittelstaedt placed the burden on the lessee to prove that it acted reasonably in using a workback method to calculate its royalty payments. Mittelstaedt, 954 P.2d at 1208; cf. id. at 1219 n.77 (Opala, J., dissenting) ("As I understand today's pronouncement, it merely limits the lessee's right to use a work-back valuation method.").

[249]. See Mittelstaedt, 954 P.2d at 1205 (prohibiting a lessee from deducting costs associated with creating a marketable product). The Supreme Court of Oklahoma has recently reaffirmed its decision in Mittelstaedt. Howell v. Texaco, Inc., 112 P.3d 1154, 1159-60 (Okla. 2004).

[250]. Id. Justice Opala, who had previously dissented from the majority opinion in Wood while he was the chief justice, filed a dissenting opinion in Mittelstaedt. However, Justice Opala retreated from his analysis in Wood and instead embraced Professor Anderson's analysis of the first marketable product doctrine. Id. at 1214 (Opala, J., dissenting) (reversing his previous position by stating, "[a]fter studying Professor Anderson's research and noting recent case law evolving in other jurisdictions, I now realize that the alternative solution I proposed in Wood--the Texas and Louisiana approach to royalty calculation--is equally flawed."); cf. supra note 238 (discussing Chief Justice Opala's dissent in Wood). Justice Opala objected that the majority opinion in Mittelstaedt did not comply with Professor Anderson's analysis, which Justice Opala characterized as the "perfect incarnation of a true first-marketable product model." Mittelstaedt, 954 P.2d at 1217 (Opala, J., dissenting).

[251]. See Lansdown, Marketable Condition Rule, supra note 28, at 688 (asserting that the Mittelstaedt court failed to give "criteria for determining whether gas [is] marketable").

[252]. Mittelstaedt, 954 P.2d at 1208; Wood, 854 P.2d at 882. After its decision in Mittelstaedt, the Supreme Court of Oklahoma concluded that overriding royalty interest owners may not bring an action for breach of the implied covenant to market. "Oklahoma has recognized that the overriding royalty interest is different from the lessor's royalty interest." XAE Corp. v. SMR Prop. Mgmt. Co., 968 P.2d 1201, 1207 (Okla. 1998); accord 2 Howard R. Williams & Charles J. Meyers, Oil and Gas Law § 420, at 360 (2004) ("The owner of an overriding royalty is not entitled to the benefit of the covenants of the base lease, express or implied, in the absence of an express provision in the instrument creating the overriding royalty."); see also Cont'l Potash, Inc. v. Freeport-McMoran, 858 P.2d 66, 81 (N.M. 1993) (acknowledging that the implied covenant is between lessors and lessees, not the overriding royalty interest holder and lessee).

[253]. See supra text accompanying notes 210-19 (discussing implied covenant to market under Sternberger).

[254]. Mittelstaedt, 954 P.2d at 1205. Before Mittelstaedt, Oklahoma courts had recognized that the implied marketing covenant was implied only in fact, not in law. E.g., Indian Territory Illuminating Oil Co. v. Rosamond, 120 P.2d 349, 354 (Okla. 1941). By requiring the lessee to prove that it acted reasonably in using a workback method to calculate royalties, Mittelstaedt suggests that the implied covenant to market now has more of an "implied-in-law" character in Oklahoma. See Hardwick, supra note 65, at 10-18 n.79 (noting that Wood, TXO, and Mittelstaedt are irreconcilable with an implied-in-fact approach to the implied marketing covenant). Specifically, by shifting the burden of proof to the lessee, Mittelstaedt assumes that the purpose of the implied covenant is not to fulfill the unexpressed intent of the parties, but rather to redistribute the respective bargaining position of the parties. See Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.04 [4], at 10-15 (analyzing the notion that "[w]hen courts place the burden of proof on the lessee, they are assuming an implied-in-law, lessor-protection role"); see also Bridenstine v. Kaiser-Francis Oil Co.,

No. 97,117, P 14, at 9 (Okla. Civ. App. Aug. 22, 2003) (unpublished decision), http:// www.oklegal.onenet.net/sample.basic.html, available at http://www.burns-stowers.com/event_detail.cfm?event_id=71 ("[S]hifting of the burden in this manner properly balanced the position of the passive nonworking interest owner (lessor) with that of the active working interest owner (lessee) in regard to their respective responsibilities and duties.") (on file with the St. Mary's Law Journal).

[255]. Compare Sternberger v. Marathon Oil Co., 894 P.2d 788, 800 (Kan. 1995) (holding, despite its recognition of the first marketable product doctrine, that the lessee had correctly used a workback method to calculate royalties where the evidence showed that the gas was marketable at the well even in the absence of a market at the wellhead), with Bridenstine, No. 97,117, PP 14-15, at 9-10 (allowing the lessee to use a workback method only if it can prove it enhanced a marketable product). Although no Oklahoma court has expressly concluded that oil or gas can only be "marketable" at a location where there is an existing market, Professor Pierce has argued that the Oklahoma version of the first marketable product doctrine tends "to assume that the actual point of sale determines when a marketable product has been achieved." Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][b], at 1-47.

[256]. 886 P.2d 652 (Colo. 1994) (en banc).

[257]. Garman v. Conoco, Inc., 886 P.2d 652, 653 (Colo. 1994) (en banc).

[258]. Id. at 654. The majority opinion in Garman did not recite any of the underlying lease or assignment terms, determining that it could "respond appropriately to the district court on the law in Colorado without considering the specific assignment terms." Id. But see Anderson, Part 2, supra note 166, at 670 ("[A]lthough the court recognized that the royalty clause may expressly override the general first-marketable product rule, the majority opinion did not rely on, nor even quote, the precise language of the overriding royalty reservation or quote the royalty clause from the underlying lease." (footnote omitted)); Kramer, Interpreting the Royalty Obligation, supra note 173, at 257 (noting that the court in Garman "did not even believe that the language creating the royalty obligation was at all relevant to define that obligation"). In a concurring opinion, Justice Erickson agreed with the majority opinion in Garman that the answer to the certified question was "No," but he concluded that, "[b]ecause the certified question refers to the assignment creating the overriding royalty interest, it is necessary to examine the exact language of the assignment." Garman, 886 P.2d at 664 (Erickson, J., concurring). According to Justice Erickson, the assignment contained a market value royalty clause, providing that "the overriding royalty payments shall be based upon the market value of gas produced, saved, and marketed from the leased property." Id.

[259]. See Garman, 886 P.2d at 661 n.27 (quoting 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351). As Professor Anderson observed:

> In Garman, the Colorado Supreme Court relied upon the implied covenant to market in reaching its decision that overriding royalty is owed on the value of a first-marketable product. In support of its view, the Colorado [c]ourt cited the late Professor Kuntz. Rather than citing to Professor Kuntz, the Garman court should have cited the late Professor Merrill as supporting that view.

Anderson, Overriding Royalty Interests, supra note 8, at 3 (footnote omitted); accord Anderson, Part 2, supra note 166, at 670 (acknowledging the court's reference to Professor Kuntz rather than Professor Merrill); see also Tooley & Tooley, supra note 77, § 21.03, at 21-6 (citing Garman for the proposition that "[j]urisdictions adopting the marketable product approach have tended to mix Professor Merrill's view of the implied covenant to market with Professor Kuntz's view of when 'production' ends").

[260]. Garman, 886 P.2d at 659 n.21 ("In Colorado we have characterized the duty to market as a covenant contained in every oil and gas lease."). This language reflects that Colorado, contrary to the prevailing precedent in other states, has found the implied covenant to market to be implied in law, not in fact. See Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.04[4], at 10-15 n.49 (suggesting a "court-defined obligation" will apply to all leases without an express disclaimer).

[261]. Garman, 886 P.2d at 659. As a consequence of the decision in Garman, Colorado, in contrast with Oklahoma, holds that an overriding royalty interest owner may enforce the implied covenant to market. Id. at n.23; see also supra note 252 (noting that in Oklahoma an overriding royalty interest owner may not enforce the implied covenant to market); cf. XAE Corp. v. SMR Prop. Mgmt. Co., 968 P.2d 1201, 1206 (Okla. 1998) (acknowledging the decision in Garman, but stating, "[w]e must disagree with our sister state's rationale as applied to the overriding royalty interest in this case").

[262]. Garman, 886 P.2d at 661. In a footnote, Garman defined "marketable" as "fit to be offered for sale in a market; being such as may be justly and lawfully bought or sold ... wanted by purchasers." Id. at 660 n.26 (quoting Webster's Third New International Dictionary 1383 (1986)). "This does not, however, provide any real guidance as to the allocation of costs in the context of oil and gas production." Lansdown, Marketable Condition Rule, supra note 28, at 690 n.106; c.f. Rogers v. Westerman Farm Co., 29 P.3d 887, 903 (Colo. 2001) (en banc) (conceding that Garman did not define the term "marketable condition").

[263]. 29 P.3d 887 (Colo. 2001) (en banc).

[264]. Rogers v. Westerman Farm Co., 29 P.3d 887, 891 (Colo. 2001) (en banc).

[265]. Id. at 893.

[266]. Id. at 891.

[267]. Id. at 902.

[268]. Id. The court in Rogers generalized that lessees have greater bargaining power than lessors. The court observed that "lessors are not usually familiar with the law related to oil and gas leases, while lessees, through experience drafting and litigating leases, generally are." Id. However, while using conditional language--such as "not usually familiar"--to soften its generalization, the court proceeded to apply a strict rule of construction to all of the leases at issue in Rogers, without specifically addressing the relative bargaining power of the plaintiffs in Rogers. However,

"[c]ontrary to the prevailing notion, not all royalty owners are unsophisticated in the ways of the oil and gas industry. Many royalty owners are corporations, trusts or professional traders." O'Neill & Keeling, supra note 29, § 6.04[2], at 6-33 (footnote omitted); see also William F. Carr & Paul R. Owen, Clear As Crude: Defending Oil and Gas Royalty Litigation, 37 Nat. Resources J. 695, 699 (1997) (arguing that sophisticated and unsophisticated royalty owners should be treated equally). Not surprisingly, the Rogers court offered no justification for applying a strict rule of construction to leases between sophisticated lessors and lessees.

[269]. Rogers, 29 P.3d at 901 (citing Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 226, 231 (5th Cir. 1984); Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983); Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 893 (Mich. Ct. App. 1997)).

[270]. Id. at 902; cf. Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[1], at 10-16 n.53 (discussing Rogers and reasoning that, "[i]n essence the court deems each lessor to be hopelessly ignorant and incapable of comprehending that the value of gas 'at the well' may be less than its downstream value after it has been gathered, compressed, dehydrated, treated, processed, and otherwise aggregated, packaged, and marketed"). The supreme court conceded that it was "in the minority" in reaching this conclusion. Rogers, 29 P.3d at 901; see Lansdown, Marketable Condition Rule, supra note 28, at 691 (criticizing Rogers's finding that "at the well" was silent as to the allocation of costs "in light of the availability of a source as basic as Black's Law Dictionary to the contrary"); see also Black's Law Dictionary 985 (7th ed. 1999) (defining "market value at the well" as "the value of oil or gas at the place where it is sold, minus the reasonable cost of transporting it and processing it to make it marketable").

[271]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.03[1], at 167 ("In Rogers the Colorado Supreme Court interpreted the phrase 'at the well' out of existence."); see also Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[1], at 10-17 n.56 (criticizing Rogers for refusing "to give any effect to the 'at the well' language"). Ironically, four years after Rogers, the Supreme Court of Colorado concluded in a property tax case that the term "at the wellhead" was neither ambiguous nor silent as to the allocation of costs. Wash. County Bd. of Equalization v. Petron Dev. Co., 109 P.3d 146, 153 (Colo. 2005). The plaintiff in Petron was a company that operated ten oil wells in Washington County, Colorado. Id. at 148. Under a tax statute requiring that operators report the "selling price" of their oil and gas production "at the wellhead," the plaintiff filed a statement in which it used a workback method to calculate the price of its production at the wellhead--subtracting gathering, transportation, and processing costs from the sales price at downstream tank batteries. Id. The county tax assessor rejected the plaintiff's valuation and instead valued the production on the basis of its sales price at the downstream tank batteries. Id. The supreme court concluded that the term "at the wellhead" has a common dictionary definition--"the physical location where the extracted material emerges from the ground." Id. at 153. On the basis of this definition, the Petron court ruled that the plaintiff had properly used a workback method to determine the price of its oil and gas production at the wellhead. Id. at 153-54.

The Colorado Supreme Court in Petron rejected the county's argument that the plaintiff's workback method of valuation was improper under Rogers. Specifically, the court stated: "The analogy between Rogers and this case is misplaced. Our decision in Rogers addresses royalty obligations under private gas leases." Id. at 154. The court noted that while it must construe a private gas lease against the lessee, "[i]n the taxation context, the benefit of the doubt goes to the taxpayer." Id. Thus, after Rogers and Petron, Colorado law inconsistently holds that a lessee may use a workback method to calculate the value of its oil and gas production for property tax purposes, but not for royalty accounting purposes.

[272]. Rogers, 29 P.3d at 902-03 (citing Garman v. Conoco, Inc., 886 P.2d 652, 660-61 (Colo. 1994) (en banc)).

[273]. Id. at 904 (referencing Professor Anderson's works heavily, but observing that it did not adopt Professor Anderson's version of the doctrine "in its entirety").

[274]. Id. at 904 n.18 (citation omitted). Citing Garman, the court in Rogers reemphasized that, at least in Colorado, "the implied covenant to market extends to both royalty interest owners and overriding royalty interest owners." Id. at 902 n.16 (citing Garman, 886 P.2d at 659-60); accord supra note 261 and accompanying text (contrasting Oklahoma and Colorado decisions concerning overriding royalty interests).

[275]. Rogers, 29 P.3d at 912-13; see also Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[1], at 10-20 ("The court's analysis in Rogers is a pure implied-in-law approach designed to give perhaps the vast majority of Colorado lessors a cost-free royalty calculated on downstream values."). Because Rogers holds that the implied covenant to market arises in every oil and gas lease to require lessees to market their production, Professor Anderson concluded that Rogers "is comparatively closer to the views of the late Professor Merrill than to this author's views or to the views of Professor Kuntz." Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-15.

[276]. Rogers v. Westerman Farm Co., 29 P.3d 887, 912-13 (Colo. 2001) (en banc). While identifying the implied marketing covenant as the source of the first marketable product doctrine, the court in Rogers did not attempt to determine whether the lessees in that case acted as reasonably prudent operators. In fact, the court implied that no prudent operator analysis was necessary. See Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[1], at 10-20 (arguing that Rogers abandoned the prudent operator analysis and replaced it with a fact issue: "[W]hether the lessee's royalty calculations reflect values associated with the sale of gas in a marketable condition at the appropriate marketing location").

[277]. Rogers, 29 P.3d at 906 (emphasis added). By describing marketability as a fact issue, the Rogers court implied, but did not specifically hold, that the plaintiff lessor bears the burden of proving the point at which oil or gas becomes marketable. Interpreting Rogers, one state district court in Colorado has held that the plaintiff bears "the burden of proof on the issue of marketability." Parry v. Amoco Prod. Co., No. 94CV105, 2003 WL 23306663, at *13 (Colo. Dist. Ct. Oct. 6, 2003).

[278]. Rogers, 29 P.3d at 905 (footnote omitted).

[279]. Id. at 905. By identifying marketability as a fact issue, Rogers creates the potential for inconsistent results; a jury in one royalty dispute may find that the lessee's production is first marketable at Point A, while a jury in another dispute may find that the same production is first

marketable at Point B. See Kramer, Interpreting the Royalty Obligation, supra note 173, at 257 (noting that external factors could influence fact finders on the question of marketable conditions). "This means each marketing decision will be open to challenge, after-the-fact, with the ultimate outcome turning on a jury's perception of the situation." Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[1], at 10-20 n.69.

[280]. Rogers, 29 P.3d at 910. But see Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-4 to -5 (criticizing Rogers and noting that "any actual arm's-length-equivalent sales of significant quantities at the well should have been sufficient to show that the gas was marketable in fact at the well").

[281]. Rogers, 29 P.3d at 910; see also Parry, 2003 WL 23306663, at *13 (holding that "a well head sale does not establish the existence of a 'market' nor that the gas is 'marketable'"). The lessees in Rogers had successfully produced sweet, dry gas from their wells. Rogers, 29 P.3d at 892. If the court had not engrafted a "marketable-location" rule on the first marketable product doctrine, the lessees would likely have had no problem showing that their production was marketable at the wellhead. As Professor Anderson has recognized, "sweet, dry gas is in a marketable condition (but not necessarily in a marketable location) at the wellhead." Anderson, Part 2, supra note 166, at 634.

[282]. Wood v. TXO Prod. Corp., 854 P.2d 880, 882-83 (Okla. 1992).

[283]. Sternberger v. Marathon Oil Co., 894 P.2d 788, 800 (Kan. 1995); see also Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][b], at 1-47 (noting that the Colorado version of the first marketable product doctrine in Rogers tends "to assume that the actual point of sale determines when a marketable product has been achieved," while the Kansas version in Sternberger "employs a more intellectually honest appraisal of the situation by noting that something can be marketable even though it has not been sold").

[284]. See 3 Williams & Meyers, supra note 51, § 645.2, at 612.4 ("It appears that the Colorado Supreme Court has done nothing less than fashion a new rule for the purpose of enhancing royalty values throughout Colorado."); McClure, Royalty Valuation, supra note 9, § 11.06[3], at 11-23 ("The effect of the Rogers decision is to replace the express terms of the lease (i.e., the phrases 'at the well' and 'market value') with the court's own (lessor-friendly) view of how the lessor-lessee relationship should be structured."); Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.04, at 10-15 n.49 ("[T]he Colorado Supreme Court [in Rogers] nullified express 'at the well' and 'market value' language in the leases to ensure its lessor-protection mission is not obstructed by having to give meaning to the contract language.").

[285]. Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-14; accord Anderson, Overriding Royalty Interests, supra note 8, at 16 ("Lessees and operators should not pay royalty on value added by transportation costs incurred to move gas to a market that is beyond the immediate vicinity of the well."); Adam Marshall, Note, Oil & Gas Law: Royalty Valuation: Rogers v. Westerman Farm Co.: Burdening Lessees With an Implied Duty to Deliver Gas to a Marketable Location, 56 Okla. L. Rev. 233, 233 (2003) (criticizing the novel marketable-location duty in Rogers). This criticism--that Rogers requires lessees to bear costs that they have not historically

borne--is ironic. It arguably applies equally to Professor Anderson's version of the first marketable product doctrine, which would forbid lessees from deducting processing, treating, and marketing costs that they historically have been able to deduct under a workback method for calculating royalties. See supra text accompanying notes 166-92 (analyzing Anderson's version of the first marketable product doctrine).

[286]. See supra note 192 and accompanying text (referencing Professor Anderson's recognition that few courts have adopted his version of the doctrine).

[287]. Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-15. Professor Anderson has not only criticized the reasoning in Rogers, but he has also complained about "the poor writing evident throughout the Rogers opinion. In addition to being repetitive and circular, the opinion is unnecessarily long, internally inconsistent, and written in a 'stream-of-consciousness' style." Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-20.

[288]. Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-16.

[289]. 557 S.E.2d 254 (W. Va. 2001).

[290]. Wellman v. Energy Res., Inc., 557 S.E.2d 254, 258 (W. Va. 2001).

[291]. Id.

[292]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 175-76. The lessee in Wellman sold its gas to Mountaineer Gas Company at a price of $2.22/Mcf. Wellman, 557 S.E.2d at 263. However, the lessee paid its lessors a royalty that it calculated on the basis of a price of $.87/Mcf. Id. Nothing in the record established the location where the lessee sold its gas to Mountaineer. See id. (analyzing only the disputed royalty calculations).

[293]. See supra note 131 and accompanying text (discussing royalty calculations under a proceeds royalty clause). The court in Wellman could also potentially have resolved the case on the basis that the term "proceeds" means "gross proceeds," not "net proceeds." If the court had done so, it might simply have concluded, without ever reaching the first marketable product doctrine, that a "gross proceeds" royalty clause does not permit a lessee to use a workback method to calculate royalties. See Hanna Oil & Gas Co. v. Taylor, 759 S.W.2d 563, 564-65 (Ark. 1988) (discussing the significance of using "proceeds" instead of "net proceeds" in a lease). According to the Hanna Oil court:

> Unless something in the context of an agreement provides otherwise, "proceeds" generally means total proceeds.... Thus, we find it unnecessary to go beyond the clear language of the agreement between the parties to hold that appellant is not entitled to deduct compression costs. If it had been their intention to do so, they would have made some reference to costs, or "net" proceeds.

Id.; accord supra note 132 (contrasting "gross" versus "net" proceeds at well). But see Parker, supra note 132, at 897 (arguing that the "general current of authority" holds that the term "proceeds" is synonymous with "net proceeds," not "gross proceeds"). Some of the language in Wellman suggests that the supreme court, in fact, intended to do exactly that--simply hold that a "proceeds" clause means "gross proceeds" and forbids the lessee from using a workback method to calculate royalties. Wellman, 557 S.E.2d at 264-65 (analyzing the terms "proceeds" and "gross proceeds" in the contract of a lease silent to the calculation of costs). If so, the court did not need to address the first marketable product doctrine, and its discussion of the doctrine is mere dicta.

[294]. Wellman, 557 S.E.2d at 265. Curiously, the court conceded that the term "at the mouth of the well" might indicate "that the parties intended that the Wellmans, as lessors, would bear part of the costs of transporting the gas from the wellhead to the point of sale." Id.; cf. Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-18 (observing that Wellman, in contrast to Rogers, "does not view 'at the mouth of the well' as being silent"). The court, however, concluded that the meaning of this language was "moot" because the lessee offered no evidence to show that its post-production costs were reasonable. Wellman, 557 S.E.2d at 265. That, of course, may have been true if the court had actually resolved the case on the basis of a lack of evidence establishing the reasonableness of these costs. But the Wellman court did not resolve the case on that basis. It instead reasoned that under a "proceeds" lease, the implied covenant to market requires a lessee to bear all costs up to the "point of sale." Id. The court's reasoning begs the question: How can an implied covenant require a lessee to bear all costs up to the point of sale when, in the court's own words, the parties adopted express terms indicating that the lessors "would bear part of the costs of transporting the gas from the wellhead to the point of sale?"

[295]. Wellman, 557 S.E.2d at 264. Although Wellman reflects only that the court defined the term "proceeds" without serious analysis, the court may have believed that the term "proceeds" means "gross proceeds" and not "net proceeds." See supra note 293 (discussing definitions of these terms). If so, the court should have tried, under the typical rules of contract construction, to analyze the conflict between the term "proceeds" and the term "at the mouth of the well." Cf. Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996) (finding "inherent conflict" in a royalty clause that uses the term "gross proceeds at the well"). The court did not do so; instead of interpreting the applicable leases on the basis of their express terms, it relied on the implied covenant to market, through the first marketable product doctrine, to determine the legal effect of the leases. Wellman, 557 S.E.2d at 264.

[296]. See supra text accompanying notes 130-32 (discussing the historical precedent governing proceeds royalty clauses).

[297]. Wellman, 557 S.E.2d at 264. The court in Wellman implied that oil and gas producers had suckered the courts in Texas and Louisiana, observing that these two states had "recognized that a lessee may properly charge a lessor with a pro rata share of such 'post-production' (as opposed to production or development) costs." Id.; cf. Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 173 (arguing that the court in Wellman "let the facts prompt it to select a rule it felt would be more protective of the royalty owner"); R. Cordell Pierce, Note, Making a Statement Without Saying a Word: What Implied Covenants "Say" When the Lease Is "Silent" on Post-Production Costs, 107 W. Va. L. Rev. 295, 324-25 (2004) [hereinafter Pierce, Note] (opining that Wellman aligns with West Virginia's tendency to favor lessors in an oil and gas lease). Having erected the strawman, the Wellman court then struck it down by incorrectly suggesting that Texas and Louisiana

were in the minority of states allowing a lessee to use a workback method to calculate royalties at the wellhead. Compare Wellman, 557 S.E.2d at 264 (mentioning only two states, Texas and Louisiana, as states that require the lessor and lessee to share post-production costs), with supra note 193 and accompanying text (listing a variety of states that follow the general rule allowing the lessee to calculate royalty payments on the basis of the price or value at the wellhead).

[298]. Wellman, 557 S.E.2d at 264 n.3; see also supra note 293 (noting that this language may indicate that the court in Wellman simply intended to conclude that the term "proceeds," standing alone, means the same as "gross proceeds" and forbids a lessee from using a workback method to calculate royalties). While making this observation, the court in Wellman distinguished itself from Professor Anderson, who has argued that the terms market value and proceeds should not have legally distinct definitions. See Anderson, Part 2, supra note 166, at 614, 683-84 (arguing that, regardless of terms, royalty should be construed first as a marketable product).

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

[300]. Id. at 264-65. The court quoted extensively from Garman, but aside from the citations to Garman, it did not cite or analyze any other first marketable product cases from Kansas, Oklahoma, or Colorado. Id.; see also Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 174 (observing that the court in Wellman "adopts a marketable product analysis without ever comparing the relative strengths and weaknesses of each approach").

[301]. Wellman, 557 S.E.2d at 265 (citation omitted).

[302]. See Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-22 to -23 (discussing Wellman's similarity to Rogers). Although Wellman is more akin to the Colorado decision in Rogers than the Kansas decision in Sternberger or the Oklahoma decision in Mittelstaedt, the Wellman court apparently reached its conclusion on transportation costs without knowledge of the Rogers decision. Id. at 13A-22; see also Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 172 (noting that "the West Virginia Supreme Court did not have the benefit of Rogers ... when it decided Wellman"). The Supreme Court of Colorado released its opinion in Rogers only four days before the Supreme Court of West Virginia issued its opinion in Wellman. Compare Rogers v. Westerman Farm Co., 29 P.3d 887, 887 (Colo. 2001) (en banc) (issued July 2, 2001), with Wellman, 557 S.E.2d at 254 (issued July 6, 2001).

[303]. Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-23. Just as Professor Anderson criticized Rogers, Anderson equally criticized Wellman for holding that a lessee must solely bear the transportation costs necessary to deliver its production to market. "[L]ike Rogers, this case [Wellman] also expands the covenant to market beyond its historical scope .... Both the Rogers and Wellman opinions reverse the traditional approach to transportation." Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-18 to -19; accord Boomgaarden, supra note 9, at 7-20 ("Rogers and Wellman have stretched the marketable-product rule to a new extreme by requiring the lessee to pay royalty on gas at the point it is in first-marketable quality and location.").

[304]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 174-75 (comparing the West Virginia approach to the Colorado approach adopted in Rogers).

[305]. See supra text accompanying notes 194-288 (tracing the case law development of the first marketable product doctrine in Colorado, Kansas, and Oklahoma).

[306]. Wellman v. Energy Res., Inc., 557 S.E.2d 254, 265 (W. Va. 2001) (emphasis added).

[307]. Id. The court did not attempt to allocate the burden of proof between the lessor and lessee, perhaps because the court's interpretation of the doctrine arguably raises no serious fact issues. Unlike in other first marketable product states where the factfinder may have to determine the point of "marketability," West Virginia may simply require that the factfinder determine the point of "sale"--a location that is not often in dispute.

[308]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.04[1], at 175 (noting that Wellman arguably states an even broader version of the first marketable product doctrine than Rogers "because it does not distinguish between expenses incurred before or after a marketable product exists"); see also Pierce, Note, supra note 297, at 326 (noting that Wellman "confuses the implied covenant to market with an obligation to enhance and transport to downstream location, where the price is higher than it would be if purchased at the well").

[309]. Stewart & Maron, supra note 19, at 651.

[310]. See, e.g., John Brätland, Economic Exchange as the Requisite Basis for Royalty Ownership of Value Added in Natural-Gas Sales, 41 Nat. Resources J. 685, 704-11 (2001) (criticizing the new implied covenant to market); Carr & Owen, supra note 268, at 706 (discussing the problems with the marketable condition rule); Lisa-Marie France, Note, Deciding to Tolerate Ambiguity: Rogers v. Westerman Farm Co. and "At the Well" Language to Determine Royalty Allocation in Oil and Gas Leases, 56 Ark. L. Rev. 903, 905-11 (2004) (analyzing Rogers); Kramer, Interpreting the Royalty Obligation, supra note 173, at 252-63 (addressing concerns with the workback methodology of determining royalties); Lansdown, Implied Marketing Covenant, supra note 98, at 332-33, 335-38 (discussing various holdings and highlighting the problems from each holding with respect to the first marketable product rule); Lansdown, Marketable Condition Rule, supra note 28, at 701-07 (addressing the problems arising from the marketable condition rule); Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-13 to -25 (analyzing the first marketable product rule); McClure, Royalty Valuation, supra note 9, §§ 11.05-.06, at 11-17 to -23 (reviewing various royalty valuation methodologies); Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05 (reviewing marketing covenant jurisprudence according to whether the covenant is implied in law or implied in fact and its impact on various aspects of the first marketable product rule); Pierce, From Extraction to Enduse, supra note 6, at 3-29 to -31 (discussing the judicial and legislative intervention into the oil and gas relationship); Poitevent, supra note 60, at 759-64 (criticizing the first marketable product states); Tooley & Tooley, supra note 77, § 21.05 (reviewing the lessee's obligations under the first marketable product doctrine); Williams et al., supra note 129, § 12.04 (examining and criticizing the expansion of the lessee's responsibilities under the implied duty to market); Pierce, Note, supra note 297, at 324-28 (criticizing the application of Wellman).

[311]. Williams et al., supra note 129, § 12.04[1], at 12-17; see also supra text accompanying notes 122-36 (reviewing the historical rules for calculating royalty payments).

[312]. Supra notes 193-94 and accompanying text.

[313]. See Lansdown, Marketable Condition Rule, supra note 28, at 704 (noting that the first marketable product doctrine "has created much of the current confusion in the courts"); see also Poitevent, supra note 60, at 759 (complaining that "a lessee in a marketable product state cannot predict its right to deduct post-production costs with certainty"). Part of the problem, of course, is that recent decisions like Rogers and Wellman have had the effect of further expanding the first marketable product doctrine. As John Burritt McArthur, an advocate of the first marketable product doctrine, has recognized in another context: "At their worst, systems of precedent can blindly replicate bad rules in ever widening circles." John Burritt McArthur, The Precedent Trap and the Irrational Persistence of the Vela Rule, 39 Hous. L. Rev. 979, 981 (2002) [hereinafter McArthur, The Precedent Trap].

[314]. Anderson, Overriding Royalty Interests, supra note 8, at 20-21; accord Anderson, Royalty Odyssey, supra note 184, § 4.07, at 4-38 (proposing a solution to the problem of varied interpretations of lease clauses). Anderson's solution is as follows:

> What is needed is convergence of royalty valuation law respecting fee leases. This need is desirable to bring certainty to the oil and gas lease bargain and, given the strategic importance of oil and gas, is also desirable public policy for the country. Unfortunately, convergence is unlikely due to the failure of jurisdictions to begin their royalty analysis from the same baseline, i.e., the same default rules.

Anderson, Royalty Odyssey, supra note 184, § 4.07, at 4-38.

[315]. See Poitevent, supra note 60, at 761 (addressing the doctrine's complications). This assertion is particularly true to the extent that the first marketable product doctrine creates questions of fact that enable a jury to evaluate a lessee's royalty calculations with the benefit of hindsight. As Scott Lansdown has observed:

> The strongest argument against the marketable condition rule is that, by abdicating any obligation to explain how the rule is to be applied with any degree of specificity, advocates of the marketable condition rule have virtually guaranteed that, if the rule is adopted, oil and gas lessees will be faced with an endless wave of expensive, burdensome and wasteful litigation.
>
> ....
>
> The existence of large numbers of factual questions, and the absence of any specific criteria for answering those questions, virtually ensures that each dispute over the marketable product rule will dissolve into a battle of experts over what a market is and when it is available to a lessee. Apart from the fact that such litigation will be prolonged and expensive, given the virtually certain lack of expertise on the part of the jury, the verdict will likely go to whichever side has experts that sound the most persuasive. In addition to the obvious inequity of this, the results of any particular case will be of virtually no use in determining the parties' rights and obligations in any other case.

Lansdown, Marketable Condition Rule, supra note 28, at 701-03.

[316]. Anderson, Overriding Royalty Interests, supra note 8, at 7; see also supra text accompanying notes 170-75 (detailing Anderson's argument advocating a "contract-law" analysis).

[317]. Supra text accompanying note 29.

[318]. Supra text accompanying note 17.

[319]. See supra text accompanying notes 60-74 (explaining "in-kind" royalties).

[320]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 160 ("Upon production the lessor has no ownership interest in the gas; 8/8ths of the gas belongs to the lessee and the lessor merely has a contractual right to a cash payment that accrues as gas is extracted."); see also supra text accompanying notes 58-59 (explaining ownership under monetary royalty clauses).

[321]. Brätland, supra note 310, at 702-03; Lowe, Defining the Royalty Obligation, supra note 40, at 257-58; Williams et al., supra note 129, § 12.02[2], at 12-18 to -19.

[322]. Rogers v. Westerman Farm Co., 29 P.3d 887, 902 (Colo. 2001) (en banc).

[323]. Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-10; accord Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.03[3], at 10-8 (discussing the landowner's bargaining power in contradiction of the claim that leases are contracts of adhesion for the landowner); Pierce, The Renaissance of Law, supra note 27, at 916 ("[I]t is the prospective lessor, as the owner of the minerals, who has the 'take-it-or-leave it' power over the transaction. [Lessors] cannot be compelled to lease their land on terms demanded by the lessee."). Unlike with insurance contracts, the terms of oil and gas leases are frequently subject to negotiation. O'Neill & Keeling, supra note 29, § 6.02[1][a], at 6-4; see also Shannon H. Ratliff & S. Jack Balagia, Jr., Oil and Gas Royalty Class Action Litigation: Pushing the Limits of Rule 23 and Comparable State Class Action Rules, 46 Rocky Mtn. Min. L. Inst. § 21.01[2][b], at 21-9 (2000) ("[O]il and gas leases are frequently and fiercely negotiated ....").

[324]. See, e.g., Sharp v. State Farm Fire & Cas. Ins. Co., 115 F.3d 1258, 1263 (5th Cir. 1997) ("Unless we first find that the policy is ambiguous, our duty is to hold the parties to the plain terms of the contract to which they have agreed ...."); Cadwallader v. Allstate Ins. Co., 848 So. 2d 577, 580 (La. 2003) ("That strict construction principle applies only if the ambiguous policy provision is susceptible to two or more reasonable interpretations ....").

[325]. See supra text accompanying notes 267-71 (discussing the application of contract construction rules in Rogers). By comparison to the court in Rogers, the Fifth Circuit in Piney Woods acknowledged the same rule of strict construction, noting that "mineral leases are construed against the lessee and in favor of the lessor." Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 235 (5th Cir. 1984). However, the Fifth Circuit concluded that the term "at the well" was unambiguous and permitted a lessee to calculate market value at the wellhead under a workback

method in which it deducted "all expenses, subsequent to production, relating to the processing, transportation, and marketing of gas and sulfur." Id. at 240.

[326]. See Creson v. Amoco Prod. Co., 10 P.3d 853, 856-57 (N.M. Ct. App. 2000) (addressing the rules of construction in contracts cases); Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121 (Tex. 1996) (discussing the construction of oil and gas leases); R&R Energies v. Mother Earth Indus., Inc., 936 P.2d 1068, 1074 (Utah 1997) (discussing contract construction); see also Kramer, Interpreting the Royalty Obligation, supra note 173, at 263 ("Oil and gas leases are not uniform. Royalty clauses are not uniform. While undoubtedly, common language is shared among different forms and widespread use of the same form exists in specific areas, courts should, as their first order of business, look to what the parties said."); Kramer, Royalty Interest, supra note 8, at 459 ("In the case of a landowner's royalty the calculation of the amount of royalty owed should depend upon the express language of the leasehold royalty clause.").

[327]. Martin v. Glass, 571 F. Supp. 1406, 1411 (N.D. Tex. 1983); Heritage Res., Inc., 939 S.W.2d at 121; see also Kramer, Interpreting the Royalty Obligation, supra note 173, at 224 (arguing that, "when the parties have articulated their intent through express language, the court's principal role, in the absence of fraud, duress, or mutual mistake, is to enforce the agreement as written"). If the parties intend that the lessee should calculate the value of its production at a point downstream of the wellhead, they can certainly draft a royalty clause which articulates their intent through express language. See supra text accompanying note 57 (offering an example of a royalty clause calling for valuation at a point downstream of the wellhead); see also Schroeder v. Terrra Energy Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App. 1997) (citing Old Kent Bank & Trust Co. v. Amoco Prod. Co., 679 F. Supp. 1435, 1445 (W.D. Mich. 1988)) (noting that "if the parties did not want to share the postproduction costs, they could have used the phrase 'at the market'").

[328]. Bruce M. Kramer, The Sisyphean Task of Interpreting Mineral Deeds and Leases: An Encyclopedia of Canons of Construction, 24 Tex. Tech L. Rev. 1, 61 (1993) [hereinafter Kramer, The Sisyphean Task]. As one of the proponents of the first marketable product doctrine has admitted, "tip-the-balance interpretive rules cannot justify a reading that is fundamentally at odds with the basic bargain in the lease." McArthur, The Precedent Trap, supra note 313, at 986-87 n.36; see also Kramer, The Sisyphean Task, supra, at 129 ("Canons when used as a substitute for the interpretational process are counter-productive.").

[329]. No concept is more basic than the proposition that a court should not rewrite a contract for the parties. See Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.01, at 10-2 ("Fundamental freedom of contract concepts require that courts enforce the parties' contract--not a contract of the court's making."); Pierce, From Extraction to Enduse, supra note 6, at 3-30 n.114 ("[I]f the contract is not truly ambiguous, the court is merely rewriting the terms of the contract--often to relieve the lessor from what now appears to be a bad bargain."). The first marketable product doctrine offends this basic proposition. See Carr & Owen, supra note 268, at 706 (noting that the first marketable product doctrine "alters the relationship between lessors and lessees by rewriting the lease contract to place new burdens on the lessee"); cf. Kramer, Royalty Interest, supra note 8, at 459 ("[C]ourts sometimes ignore the express language in order to reach results that are deemed to serve other public purposes than freedom of contract.").

[330]. See Martin, 571 F. Supp. at 1411 (noting that the definition of the term "at the well" is "well settled"); Atl. Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) (noting that the definition of the term "at the well" is "commonly understood"); Creson, 10 P.3d at 857 (noting that the definition of the term "at the well" is "unambiguous"); see also supra notes 118-21 and accompanying text (discussing the unambiguous nature of the term "at the well"). But see France, supra note 310, at 903 (arguing that the term "at the well" is ambiguous and that courts should "use traditional principles of contract interpretation to ascertain the parties' intent in including the language in the lease"). Given the historical precedent holding that the term "at the well" had a plain meaning, no one can seriously fault lessees and lessors for using the term in royalty clauses. "Clearly, once contractual language has received a definitive interpretation, the lessor may fairly be charged with being aware of that interpretation; it is also the case that the lessee ought to reasonably be able to rely on it." Lansdown, Marketable Condition Rule, supra note 28, at 700.

Even assuming for the sake of argument that the historical precedent is incorrect and the term "at the well" is ambiguous, a court should not simply ignore the term and summarily adopt the first marketable product doctrine. See supra text accompanying notes 322-25 (criticizing the inappropriate application of contract construction rules in first marketable product states). Rather, once a court deems the term ambiguous, it should seek to determine the intent of the parties at the time that they entered into the lease. Especially if the lessor has experience in oil and gas matters, a court may conclude that the lessor was familiar with the customary usage of the term "at the well" in the oil and gas industry and willingly agreed that the lessee could calculate its royalty payments on the basis of the price or value of its production at the wellhead. See Pierce, Industry Custom & Usage, supra note 171, at 469 (discussing industry "custom and usage" evidence and its role in lease constructions).

[331]. See Rogers v. Westerman Farm Co., 29 P.3d 887, 897 (Colo. 2001) (en banc) (arguing that the term "at the well" is "silent with respect to the allocation of costs"); see also Wellman v. Energy Res., Inc., 557 S.E.2d 254, 257 (W. Va. 2001) (suggesting that a lease providing for the payment of a share of proceeds at the well requires that the lessee pay royalties on its gross proceeds, without deducting any production, marketing, or transportation costs). But cf. Williams et al., supra note 129, § 12.07, at 12-69 ("[T]o say that a lease royalty clause expressly providing for royalty to be based on value 'at the well' is somehow silent or ambiguous on the allocation of post-production costs, is mere sophistry. What other possible purpose could such words have?").

Professor Anderson agreed that the Rogers court erred in failing to give any effect to the words "at the well." Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-9 ("Declaring silence is not the same as giving meaning and harmony."). Anderson tried to give effect to the words "at the well" by arguing that they determined only the proper location for calculating royalties on production, not the condition of the production. Id. Thus, Anderson suggested that the words "at the well" allowed the lessee to calculate royalties by deducting transportation costs--but not by deducting treating, processing, or marketing costs--from the downstream sales price for a first marketable product. See supra text accompanying notes 183-87 (discussing Anderson's definition of the words "at the well"). His interpretation begs the question: What, in the three words "at the well," expresses the intent that the lessee may deduct transportation costs but not treating, processing, or marketing costs? Anderson's attempt to distinguish between location and condition is unpersuasive. If the words "at the well" adequately express the intent that the wellhead is the proper location for calculating royalties, then the same words should also adequately express the intent that the wellhead is the proper location for determining the value (i.e., the "condition") of the very product that is the subject of the contract between the parties.

[332]. See, e.g., Fremont Indem. Co. v. Cal. Nat'l Physician's Ins. Co., 954 F. Supp. 1399, 1403-04 (C.D. Cal. 1997) ("Basic rules of contract interpretation require that the reader give effect to all of the words making up a particular provision of the contract."); Seattle-First Nat'l Bank v. Westlake Park Assocs., 711 P.2d 361, 364 (Wash. Ct. App. 1985) ("An interpretation which gives effect to all of the words in a contract provision is favored over one which renders some of the language meaningless or ineffective.").

[333]. See Altman & Lindberg, supra note 28, at 366-67 (stating that measuring the lessee's market obligations "at the wellhead" is the universal and most logical standard); Lansdown, Marketable Condition Rule, supra note 28, at 700 (discussing the policy grounds of the marketable product rule). Effectively, the first marketable product doctrine strikes the term "market value [or market price] at the well" and substitutes the term "the price that the lessee received at the point where the lessee first obtained a marketable product." The typical royalty clause, however, contains no such language. Nor does any such language necessarily flow from the assumption that the term "market value" presupposes a "market." The doctrine could just as easily have chosen any number of other substitute terms--"market value at the tailgate of the treatment plant," "the actual price received by the lessee at the point where the lessee first sells its production to a third party in an arm's-length contract," "the closest applicable index or posted price," etc. By picking a new measure of royalty calculation essentially out of thin air, the doctrine does exactly what fundamental contract law expressly forbids--it asks a court to create a new contract for the parties. See supra note 329 (criticizing courts for rewriting contracts).

[334]. Piney Woods Country Life Sch. v. Shell Oil Co., 539 F. Supp. 957, 971 (S.D. Miss. 1982), aff'd in part, rev'd in part on other grounds, 726 F.2d 225 (5th Cir. 1984); Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.--Corpus Christi 1986, no writ); see also Brätland, supra note 310, at 702-03 (describing the wellhead as the point of demarcation); Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-12 (noting that production occurs at the wellhead where oil and gas is captured and held); Richard C. Maxwell, Oil and Gas Royalties--A Percentage of What?, 34 Rocky Mtn. Min. L. Inst. § 15.03[1], at 15-15 to -16 (1988) (discussing when oil and gas is valued); supra text accompanying note 116 (defining "production"); cf. Wood v. TXO Prod. Corp., 854 P.2d 880, 884 n.9 (Okla. 1992) (Opala, C.J., dissenting) ("The 'place of production' is generally viewed as being the wellhead.").

[335]. Webster's New World Dictionary 1073 (3d college ed. 1988); see also Black's Law Dictionary 1088 (5th ed. 1979) (defining "produce" to mean "[t]o bring to the surface, as [in] oil"). A royalty is a share, either in kind or in money, of the "production" from a lease. See Howard R. Williams & Charles J. Meyers, Manual of Oil and Gas Terms 970-73 (9th ed. 1994) (defining royalty and the two types of royalties). Accordingly, a royalty typically is "free of the costs of production because pre-production costs are required to create the production from which the royalty share comes. Logically, then, royalty may be subject to costs subsequent to production." Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-12.

[336]. See Rogers, 29 P.3d at 901 ("[W]e decline to follow the rule that gas is 'produced' once physically severed ...."); see also Carr & Owen, supra note 268, at 697 (explaining that the first marketable product doctrine "extends the definition of 'production' from the well where the product is in an unprocessed state to the point where a marketable product is obtained that could be far downstream from the well or other point of valuation set by the lease"). The first marketable product doctrine arguably creates a different definition of "production" for money royalties than for in-kind royalties. Under an in-kind royalty clause, the lessor is entitled to receive a proportional royalty share of the lessee's "production." See supra text accompanying notes 60-64 (discussing delivery of royalty in kind). Historically, the lessor under such a royalty clause acquires title to his royalty oil at the wellhead. See supra text accompanying note 65 (stating the same). However, if "production" does not end until a lessee obtains a first marketable product, the definition of "production" under the first marketable product doctrine raises the following question: Where does a lessor acquire title to royalty oil under an in-kind royalty clause--at the wellhead or at the location of the first commercial market? Cf. infra text accompanying notes 354-56 (noting that the first marketable product doctrine is unfair to lessors who receive royalties in kind).

[337]. Rogers, 29 P.3d at 904.

[338]. Anderson, Part 2, supra note 166, at 645; cf. Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 129-30 (Tex. 1996) (Owens, J., concurring) (arguing for consistency in courts' construction of words commonly used in oil and gas leases and stating, "we must keep in mind that there is a need for predictability and uniformity as to what the language used means. Parties entering into agreements expect that the words they have used will be given the meaning generally accorded to them.").

[339]. Anderson, Part 2, supra note 166, at 683; see also Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-9 ("When read as a whole, these phrases ['market value at the well' or 'net proceeds at the well'] plainly state that royalty is payable on a marketable or salable product--otherwise there could be no proceeds, market value, or market price ...."). This assumption begs the question: "Just what is the relevant market?" For example, "[b]ecause 'wet' gas has a 'rich' hydrocarbon dew point, it is 'marketable' to the gas plant but 'unmarketable' to the interstate pipeline market. Conversely, because 'dry' gas has a 'lean' hydrocarbon dew point, it is 'unmarketable' to the gas plant, but 'marketable' to the interstate pipeline market." Thomas C. Jepperson, Royalties on Processed Gas, Special Inst. on Private Oil & Gas Royalties pt. 11, at 11-24 (Rocky Mtn. Min. L. Found. 2003) (footnote omitted) (on file with the St. Mary's Law Journal).

[340]. See Shackleford v. United States, 262 F.3d 1028, 1033 (9th Cir. 2001) ("[T]he lack of a market ... does not mean that the asset cannot be valued .... Where a willing seller and willing buyer do not exist, we will presume both their presence and a hypothetical sale."); Trigon Ins. Co. v. United States, 215 F. Supp. 2d 687, 709 (E.D. Va. 2002) ("The case law establishes that the willing buyer/willing seller standard governs the determination of the fair market value of an asset even if there is no established market for the asset and even if the particular asset cannot in fact be sold."); see also Guggenheim v. Rasquin, 312 U.S. 254, 258 (1941) (stating "the absence of market price is no barrier to valuation" for a life insurance policy); Bankers Trust Co. v. Bethlehem Steel Corp., 658 F.2d 103, 106 (3d Cir. 1981) (stating that courts may use various factors in determining the market

value of a crude oil tanker); In re WRT Energy Corp., 282 B.R. 343, 406 (Bankr. W.D. La. 2001) (discussing the use of the hypothetical willing seller and willing buyer for debtors' oil and gas properties). The Uniform Commercial Code recognizes that the terms "market value" or "market price" do not require an actual commercial market, and in fact, permits courts to use a form of the workback method to calculate a "market price" for commercial goods in the absence of a market at the point of valuation. See U.C.C. § 2-723(2) (2000) (giving the standard for the time and place to prove the market price of goods). According to the U.C.C.:

> If evidence of a price prevailing at the times or places described in this Article [entitled "Proof of Market Price: Time and Place"] is not readily available the price prevailing ... at any other place which in commercial judgment or under usage of trade would serve as a reasonable substitute for the one described may be used, making any proper allowance for the cost of transporting the goods to or from such other place.

Id. (emphasis added).

[341]. See Bank of Cal. v. Comm'r, 133 F.2d 428, 433 (9th Cir. 1943) (noting that even if a party's claim of property "was not assignable, it still could have a fair market value").

[342]. See Sternberger v. Marathon Oil Co., 894 P.2d 788, 800 (Kan. 1995) (stating that, "[i]n the case before us, the gas is marketable at the well. The problem is there is no market at the well ...."); accord Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][b], at 1-47 ("[O]ne can have a marketable product without having anyone willing to buy it at a particular location."); see also Scott Paper Co. v. Taslog, Inc., 638 F.2d 790, 799 (5th Cir. Unit B Mar. 1981) (finding that "[t]he absence of an available market does not mean that the gas lacks value").

[343]. See supra text accompanying notes 193-308 (discussing the first marketable product doctrine case law).

[344]. See 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 350-51 (observing that "it is considerably more difficult to reason from such [a] general duty [the lessee's duty to market the gas under the implied covenant to market] to a conclusion as to which party or parties must bear any added expense which might be incident to preparing the gas for market"); Anderson, Part 2, supra note 166, at 684 (stating, "[t]here is no need to resort to the implied covenant to market to reach this conclusion").

[345]. Lansdown, Implied Marketing Covenant, supra note 98, at 348-49; see also Irvin, supra note 54, § 18.04[4], at 18-34 ("[T]he implied covenant to market, at least historically, has been viewed as a duty to use reasonable diligence in seeking a market and not as a duty relating to the amount of royalty to be paid."); Tooley & Tooley, supra note 77, § 21.06[3], at 21-35 (noting that, to the extent that the implied covenant to market requires the lessee to obtain the best price reasonably available, the lessee may fulfill this obligation, at least historically, by obtaining "the best price reasonably available ... at the well, not at other higher priced markets"); cf. Piney Woods Country Life Sch. v. Shell Oil Co., 539 F. Supp. 957, 972 (S.D. Miss. 1982) (discussing the implied covenant to market and concluding that "this duty does not require an assumption of all costs"), aff'd in part, rev'd in part on other grounds, 726 F.2d 225 (5th Cir. 1984).

[346]. See Williams et al., supra note 129, § 12.04[4], at 12-25 ("[I]mplied covenants are tools to ascertain and effectuate the intent of the parties, not rewrite the contract to the satisfaction of the court."); see also supra text accompanying notes 37-39 (proposing that a court should not use an implied covenant to contradict the express terms of a contract).

[347]. See Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 895-96 (Mich. Ct. App. 1997) ("[W]e see no reason to require [the] defendant to bear fully the cost of postproduction marketing where the express royalty clause delineates how such costs are to be apportioned."). As Lansdown has explained:

> The basic purpose of the implied covenants is to address those matters that have not been addressed by the express provisions of the applicable lease. With this purpose in mind, it is clear that the implied covenants have nothing to do with the allocation of postproduction costs. Most leases provide that royalty is to be calculated at the well and, even when the leases do not so provide, that is the generally recognized rule of interpretation. Because the parties' rights are clearly defined under the lease and under applicable law, there is no reason to look to the implied covenant to market, or any of the other implied covenants, for further interpretation of these rights.

Lansdown, Implied Marketing Covenant, supra note 98, at 336 (footnote omitted); accord Tooley & Tooley, supra note 77, § 21.07, at 21-37 (reiterating that, "[w]here the parties expressly agree to the point at which the lessor's royalty is to be valued or determined, such express terms should be given meaning," as opposed to applying an implied covenant).

[348]. Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 374 (Tex. 2001); see also Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[2], at 10-22 ("The court's analysis in Yzaguirre is consistent with the interpretive role of implied covenants: if the meaning of the lease can be determined without an implied covenant, no covenant will be implied.").

[349]. See 5 Williams & Meyers, supra note 105, § 803, at 18.3-19 (discussing the trend of implied covenants to market being construed as implied in fact); see also supra text accompanying notes 104-09 (discussing implied covenants as being implied in fact).

[350]. Lowe, Interpreting the Royalty Obligation, supra note 33, at 6-35.

[351]. Rogers v. Westerman Farm Co., 29 P.3d 887, 912-13 (Colo. 2001) (en banc); see also supra text accompanying notes 275-76 (discussing the same).

[352]. Smith v. Amoco Prod. Co., 31 P.3d 255, 268 (Kan. 2001).

[353]. Pierce, Exploring the Jurisprudential Underpinnings, supra note 210, § 10.05[3], at 10-27 to -28; see also supra notes 221-25 (discussing the Kansas Supreme Court's holding in Smith).

[354]. See supra text accompanying notes 76-78 (discussing the historical roots of the implied covenant to market).

[355]. See Wall v. United Gas Pub. Serv. Co., 152 So. 561, 563 (La. 1934) (noting that title to in-kind royalties vests at the well because that is where the commodity comes into the possession of the lessee); see also Jepperson, supra note 339, at 11-15 ("A consistent rationale in all the early processed gas cases is the notion that there ought to be value and volume symmetry in royalty application, i.e., point-of-value for proceeds ought to coincide with point of delivery for gas taken in-kind."); Matlock, supra note 97, § 9.06[1], at 9-40 ("The implied covenant to market is an attempt to put the lessor in the same position it would have been in if it had so taken in kind and then sold its share of production at the wellhead.").

[356]. See Hardwick, supra note 65, § 10.09[1], at 10-31 (analyzing the differences between "in value" and "in kind" royalty clauses with respect to post-production costs). Hardwick concludes the following:

> [I]t may be argued that a consequence of the royalty owner's ownership of the product at the well [under an in-kind royalty clause] is that the royalty owner acquires the royalty oil "as is, where is"--warts and all. If there is an expense to get the oil to market, then the royalty owner must bear that expense. If the oil requires treatment before it will be acceptable to a purchaser, then the royalty owner must bear that cost.

Id.; see also Gary B. Conine, Speculation, Prudent Operation, and the Economics of Oil and Gas Law, 33 Washburn L.J. 670, 690-91 (1994) (arguing that the lessee's marketing practices are "irrelevant" under an in-kind royalty clause); Poitevent, supra note 60, at 725 (expounding that Louisiana's position that valuation be made "at the well" treats in-kind royalty owners in the same manner as royalty owners who receive monetary royalties).

[357]. Kramer, Royalty Interest, supra note 8, at 459; see also Sowell v. Natural Gas Pipeline Co. of Am., 604 F. Supp. 371, 379 (N.D. Tex. 1985) (holding that a lessor could not recover royalties on the enhanced downstream value of processed gas), aff'd, 789 F.2d 1151 (5th Cir. 1986); Carter v. Exxon Corp., 842 S.W.2d 393, 397 (Tex. App.--Eastland 1992, writ denied) (ruling that a lessor was not entitled to receive royalties on natural gas liquids manufactured from the gas stream); Lowe, Defining the Royalty Obligation, supra note 40, at 257-58 ("History and logic suggest that the scope of the royalty obligation should be limited to the fruits of lessees' production functions, which typically occur at or near the wellhead, and should not extend to entrepreneurial functions such as marketing, transportation or processing." (footnotes omitted)). Even Professor Anderson agrees that a lessee should not have to share its profits with its lessors--but only after the lessee has first acquired a marketable product. See Anderson, Calculating Freight, supra note 189, at 345 (asserting his view that "lessees should not have to share downstream net profits with lessors" and concluding that "I would not permit the taking of profits through royalty accounting").

[358]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 160 ("The lessors' interests, with regard to their lessees, typically end once the gas is extracted from the ground and used or sold by the lessee.").

[359]. See Matlock, supra note 97, § 9.06[2], at 9-46 ("The lessor is not committing its capital, assets and credit to the separate business of the downstream marketing of gas, and is not taking any of the risks of that business."); see also Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][c], at 1-49 n.239 (asserting that the lessor does not share in the risks); Tooley &

Tooley, supra note 77, § 21.04[2][a], at 21-9 to -10 (pointing out the minimal risk of lessors in terms of costs).

[360]. See Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 159 (noting that the value of gas at a downstream location encompasses not just the costs of transporting the gas, but also the "additional risk, capital, effort, and skill associated with the downstream processing business").

[361]. See Siefkin, supra note 118, at 200-01 (advancing the idea of computing royalties at the wellhead); Tooley & Tooley, supra note 77, § 21.05[3][d], 21-29 to -30 (discussing the proposition as it applies to the recovery and processing of "wet" gas).

[362]. Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][b], at 1-48; see also Brätland, supra note 310, at 704-05 ("Unless the royalty owner shares the post-production cost associated with marketing the gas, he has engaged in no act of exchange to establish additional royalty ownership or equity interest in value added beyond the point of production--the wellhead."); McClure, Royalty Valuation, supra note 9, § 11.05[1][b], at 11-18 ("[R]oyalty owners are getting 'something for nothing'--a share of post-production profits that was never bargained for in the original lease."); cf. Anderson, Calculating Freight, supra note 189, at 345 ("[L]essees should not have to share downstream net profits with lessors in a marketable-product jurisdiction.").

Some commentators have tried to justify this result by citing to case law suggesting that a lessee shares a "cooperative venture" or "joint venture" relationship with its lessors. See, e.g., McArthur, The Mutual Implied Benefit Covenant, supra note 36, at 870-71 (arguing for an implied mutual benefit covenant on the basis of an alleged cooperative venture between the lessor and lessee). A few states--notably Oklahoma, Arkansas, and Louisiana--have in fact used the term "cooperative venture" to describe the contractual relationship "between the lessor, who owns the minerals, and the lessee, who possesses the money and expertise to develop the minerals." Lowe, Defining the Royalty Obligation, supra note 40, at 251-52 (discussing "cooperative venture jurisdictions" and citing cases). However, if accurate at all, the term "cooperative venture" only defines the relationship between the parties at the point where the lessee actually fulfills the purpose of the "venture" and extracts minerals from the ground; it does not accurately define the relationship between the parties downstream of the leased premises (after the lessee has extracted the minerals from the ground). See Pierce, The Royalty Value Theorem, supra note 5, § 6.02, at 160 (addressing issues arising when the lessee owns downstream gas processing facilities and pointing out that lessors are not typically co-owners of these downstream facilities); Stewart & Maron, supra note 19, at 653-54 (discussing the term "cooperative venture"). Indeed, if a lessor truly had a "cooperative venture" or "joint venture" relationship with his lessee downstream of the leased premises, the parties would have to be joint and equal venturers sharing "not just in the profits, but [in] the costs and losses as well." Stewart & Maron, supra note 19, at 653; cf. Pierce, The Royalty Value Theorem, supra note 5, § 6.01[1], at 152 (observing that the lease relationship is the "classic uncooperative venture").

[363]. See Pierce, Developments in Nonregulatory Oil and Gas Law, supra note 139, § 1.07[4][a], at 1-39 to -43 (discussing the inherent flaws in using the first marketable product doctrine to trump express lease terms); cf. McClure, Royalty Valuation, supra note 9, § 11.07[1], at 11-23 to -24

(discussing the illogical results of the first marketable doctrine in a scenario where the lessee sells its production under a percentage-of-proceeds [POP] contract).

[364]. See Kramer, Interpreting the Royalty Obligation, supra note 173, at 257 (analyzing royalty valuation in Colorado under Garman and Rogers); cf. Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 893 n.5 (Mich. Ct. App. 1997) (refusing to adopt the first marketable product doctrine because it "would establish as the valuation point whatever location at which the gas ultimately becomes marketable, thereby resulting in potentially different valuations for the product of the same well"). Suppose, for example, a scenario in which a lessee sells a portion of its gas production to a purchaser at the wellhead and the remainder to a downstream purchaser. The lessee may argue that the fact that it sells a portion of its gas production at the wellhead proves that the gas is marketable at the wellhead--and, therefore, that the proper location for calculating the value or price of its production is the wellhead. In Colorado, however, a lessee cannot prove that its production was marketable at the wellhead simply by showing that it sold a portion of its production to a wellhead purchaser. Rogers v. Westerman Farm Co., 29 P.3d 887, 910 (Colo. 2001) (en banc); see also Boomgaarden, supra note 9, at 7-21 (criticizing the decision in Rogers because it potentially allows lessors to "challenge any arm's[-]length transaction at the wellhead on grounds the sale was not consummated at the required 'commercial marketplace'"); supra note 278 and accompanying text (quoting the Colorado Supreme Court in Rogers, which sets forth the notion that, of the two factors for courts to consider in defining the marketability of gas, the "location" factor is determined by the "commercial marketplace"). In West Virginia, even if a lessee acquires a marketable product at the wellhead, the lessee arguably may have to pay its lessors a proportionate share of the actual price that the lessee receives at the actual point of sale. Wellman v. Energy Res., Inc., 557 S.E.2d 254, 265 (W. Va. 2001); see also supra text accompanying notes 302- 06 (explaining the first marketable product doctrine under Wellman).

[365]. See Kramer, Royalty Interest, supra note 8, at 470 (noting the value of sour gas is less than the value of sweet gas).

[366]. See Poitevent, supra note 60, at 719 (observing that in first marketable product states, the "cost to treat gas may not be deducted to the extent it is required to place the gas in a marketable condition"); cf. Altman & Lindberg, supra note 28, at 379 (concluding that "[i]t defies logic to argue that where gas cannot be sold at the wellhead because of its inferior quality the lessee's duty to market gas can be converted into a duty to render the gas more valuable than it actually was, all at his own expense"). By holding that royalties on sour gas should be largely the same as royalties on sweet gas, the first marketable product doctrine rewards those lessors who own royalty interests in inferior production and punishes those lessors who own royalty interests in superior production. See Brätland, supra note 310, at 708 (explaining the negative effect on an investor's incentive to finance additional productive capacity). In this context, the doctrine is the oil and gas equivalent of a component supply contract that requires a manufacturer to pay the same price for (a) a "superior" widget that the manufacturer may directly incorporate into its product without modification as for (b) an "inferior" widget that the manufacturer must re-tool, at its own expense, before incorporating into its product. As a matter of economics and common sense, the manufacturer should pay a lower price for the inferior widget because the manufacturer will have to sink additional costs into the widget to modify it for use in the final product. But having entered into a contract requiring it to pay

the same sticker price for the superior widget and the inferior widget, the manufacturer will reward the supplier of the inferior product by paying a sticker price that exceeds the true economic value of the widget--a sticker price which should, but does not, take into account the additional costs that the manufacturer must incur to modify the widget to produce a marketable final product. Cf. Lansdown, Marketable Condition Rule, supra note 28, at 704-06 (illustrating that the first marketable product doctrine would result in (a) higher royalties for a lessor whose lessee produces sour gas at the well and bears the costs of treating the gas before selling it to a downstream purchaser, but (b) lower royalties for a lessor whose lessee produces sour gas at the well and sells the gas to a wellhead purchaser that bears the costs of treating the gas for subsequent resale).

[367]. See Brätland, supra note 310, at 708 (expressing the concern that "royalties on value added create a bias against the development of lower quality gas resources (marginal, lower quality gas deposits ... will remain undeveloped because the royalty collected on value added makes the expected net present value of projects either negative or too small to warrant development)").

[368]. In criticizing the "marketable location" component of the decision in Rogers, Professor Anderson argued that "the market-location rule will adversely affect the marketing of gas by encouraging the creation of markets at or near the wellhead even though that location may not be the most efficient marketplace." Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-25; accord Anderson, Royalty Odyssey, supra note 184, § 4.03, at 4-20 ("In addition to upsetting well[-]established principles, the marketable-location rule will adversely affect the marketing of gas by encouraging producers to market gas close to the wellhead even though that location may not be the most efficient marketplace."). Although Anderson is an advocate of the first marketable product doctrine, his criticism of the marketable location component of Rogers applies equally to his version--as well as every other version--of the first marketable product doctrine. See Lansdown, Marketable Condition Rule, supra note 28, at 707 ("There does not appear to be any reason ... to believe that the marketable-location rule will discourage lessees from seeking optimal markets, while the marketable condition rule will not.").

[369]. Carr & Owen, supra note 268, at 706. Carr and Owen argue that under the first marketable product doctrine:

> Production that now is gathered, dehydrated, compressed or otherwise treated by the lessee will be sold at the well in its unprocessed state to third parties who will then perform these downstream value-enhancing activities.
>
> These new arrangements will inject a new step into the process of producing and marketing oil and natural gas. The cost of conducting these post-wellhead activities through third parties should be higher than the cost of having the lessee perform these services.

Id. Advocates of the first marketable product doctrine may argue that this scenario is unlikely because the doctrine only applies where the lessee cannot market its production at the wellhead. This argument incorrectly assumes, however, that markets will not adjust to market conditions. Anyone who has spent any time shopping at a flea market or garage sale knows that even seemingly undesirable goods or products may be marketable to someone who is willing to invest the time and expense to "fix them up." Likewise, even seemingly undesirable oil or gas production, such as sour gas, may be marketable at the wellhead to a purchaser who determines that he can generate a profit on reselling the gas at a downstream market. See West v. Alpar Res., Inc., 298 N.W.2d 484, 493 (N.D. 1980) (Pederson, J., concurring) (stating, "In my opinion, 'sour' gas at a 'wellhead' is marketable and has a market value"). Unlike the lessee in a first marketable product state, the purchaser will not have to pay any royalty on the downstream sales price of the production and, therefore, will not have to factor any royalty expense into its profit analysis. Cf. Lansdown, Marketable Condition Rule, supra note 28, at 705-06 (arguing that the lessee in a first marketable product state has no incentive to enhance the product). According to Lansdown's analysis:

> [T]he failure to allow deductions in a scenario where the lessee has the option of performing a post-production operation itself or selling the product at the wellhead to a buyer that performs the operation can make it uneconomical for the lessee to engage in an operation that would enhance the value of the product ....

Id.

[370]. Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-3.

[371]. 3 Kuntz, 1989 ed., supra note 1, § 40.5(b); Anderson, Part 1, supra note 166, at 549.

[372]. 3 Kuntz, 1989 ed., supra note 1, § 40.5(b); Anderson, Part 2, supra note 166, at 683.

[373]. Rogers v. Westerman Farm Co., 29 P.3d 887, 904 (Colo. 2001) (en banc); see Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1210 (Okla. 1998) (holding that deductions for post-production costs are allowed if these costs are incurred to "transform[ ] an already marketable product into an enhanced product").

[374]. Rogers, 29 P.3d at 904 (emphasis added).

[375]. See Garman v. Conoco, Inc., 886 P.2d 652, 661 (Colo. 1994) (en banc) ("Upon obtaining a marketable product, any additional costs incurred to enhance the value of the marketable gas ... may be charged against nonworking interest owners."); see also Rogers, 29 P.3d at 906 (recognizing that transportation costs are to be shared by lessors and lessees after the lessees have obtained a first marketable product); Mittelstaedt, 954 P.2d at 1210 (summarizing the types of post-production costs that are to be borne by a royalty-interest owner when the lessee shows the costs are related to enhancing an already marketable product).

[376]. See supra text accompanying notes 309-70 (discussing the flaws in the first marketable product doctrine).

[377]. See Jepperson, supra note 339, at 11-3 ("With the possible exception of coal bed methane wells, very few wells produce only oil or gas. Most gas wells produce some oil and most oil wells produce some gas.").

[378]. J.T. Mitchell, From Extraction to End Use: The Marketing Background, Special Inst. on Private Oil & Gas Royalties pt. 2, at 2-1 (Rocky Mtn. Min. L. Found. 2003) (on file with the St. Mary's Law Journal).

[379]. Id.

[380]. Id.

[381]. See Jepperson, supra note 339, at 11-25 (contending that the implied covenant to market does not place a duty on the lessee to put the gas in "pipeline quality" because "[t]he lessee's duty to market should end at the lease line").

[382]. See Kramer & Pearson, supra note 81, at 797 (identifying the language of a typical habendum clause in an oil and gas lease); see also supra text accompanying note 86 (explaining that most oil and gas leases contain a habendum clause).

[383]. Anderson, Calculating Royalty, supra note 125, at 631.

[384]. See Clifton v. Koontz, 160 Tex. 82, 325 S.W.2d 684, 689-91 (1959) (defining the term "paying quantities").

[385]. Anderson, Calculating Royalty, supra note 125, at 631.

[386]. Anderson, Part 2, supra note 166, at 684-86. Anderson observes:

> Courts need only consider the object of the lease in light of its purpose: the production of hydrocarbons that generate income to the lessee and a cost-free royalty share to the lessor. To fulfill this objective, the lessee must have a product to market and must market that product (or pay the lessor for its value in the vicinity of the well) without cost to the lessor.

Id. (footnote omitted).

[387]. Id. at 686. Anderson argues that under his version of the first marketable product doctrine:

> the lessee would not be obliged to move the gas further downstream to a secondary or tertiary market [after acquiring a first marketable product] and, if the lessee did so, the lessee would not be obliged to share any generated profits with, or permitted to pass on any losses to, the lessor.

Id.; see also id. at 683 (specifying that "lessees should not have to pay royalty on any value added to production by reason of 'post-production' activities"); id. at 689-90 (stating that "a lessor should not expect to receive royalty on the value of production after it has passed beyond the exploration and production segment of the industry").

[388]. Some leases "address condensate under the oil royalty clause, [while] others expressly address [condensate] under the gas royalty clause." Pierce, From Extraction to Enduse, supra note 6, at 3-12 (footnote omitted). Somewhat unrealistically, this hypothetical assumes that "market value at the well" royalty language applies both to gas production and oil production. Nonetheless, even if the lease in this hypothetical were to have two separate royalty clauses with different language for gas production than for oil production--for example, a "market value at the well" royalty clause for gas production, and a "net proceeds at the well" royalty clause for oil production--the first marketable product doctrine would likely treat the respective clauses as if they were identical. See Anderson,

Part 2, supra note 166, at 613-14, 683-84 (concluding that regardless of the royalty provisions, production is complete only when the lessee obtains a first marketable product).

[389]. A "condensate reservoir" is typically a deep field "with pressures above 4,000 [sic] pounds per square inch ... and at temperatures above 200˚ F ... contain[ing] single-phase fluids that are not distinctly oil or gas." Kyle L. Pearson, From Extraction to Enduse: The Technical Background, Special Inst. on Private Oil & Gas Royalties pt. 1, at 1-2 (Rocky Mtn. Min. L. Found. 2003) (on file with the St. Mary's Law Journal). "As the fluid is produced to the surface, the pressure is decreased and two distinct phases are formed: a gas phase and a liquid condensate." Id.

[390]. Cf. infra text accompanying notes 396-402 (noting that even in a first marketable product state, a lessee should be able to calculate its royalty payments at the wellhead where it can identify a potential purchaser at the wellhead).

[391]. See supra text accompanying note 126 (defining the workback method for calculating royalty payments).

[392]. Sour gas is gas that contains detectable levels of hydrogen sulfide, carbon dioxide, and other acid gases or impurities. See Francis S. Manning & Richard E. Thompson, Oilfield Processing of Petroleum Volume One: Natural Gas 6 (1991) (distinguishing between sweet gas and sour gas). The treating process removes these impurities from the gas stream. As a condition for transporting gas, transmission pipelines generally require that the gas stream contain no more than 4 ppm of hydrogen sulfide and no more than 1 to 2% of carbon dioxide. Id.; see also Pearson, supra note 389, at 1-10 (providing details on the treating process).

[393]. See Manning & Thompson, supra note 392, at 3-4 (describing the separation process for condensate); Mitchell, supra note 378, at 2-1 (defining condensate).

[394]. See Norman J. Hyne, Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production 12 (2d ed. 2001) (stating that "refiners pay almost as much for condensate as crude oil"); see also Pearson, supra note 389, at 1-2 (noting that condensate is usually sold as crude oil).

[395]. Cf. State Dep't of Revenue v. Amoco Prod. Co., 7 P.3d 35, 39 (Wyo. 2000) (noting that any calculation under the netback method must begin at the correct "starting point").

[396]. See supra text accompanying note 125 (defining the comparable sales method for calculating royalty payments).

[397]. See supra text accompanying notes 122-28 (observing that courts prefer the comparable sales method to the workback method for calculating royalties). Absent any evidence of comparable sales, a lessee in a state that has rejected the first marketable product doctrine may, of course, use the workback method to calculate its royalty payments on sour gas production. This is not unfair. A royalty owner under a lease that produces sour gas should not expect to receive the same royalties as a royalty owner under a lease that produces sweet gas. Kramer, Royalty Interest, supra note 8, at 470. As Kramer explains:

> Where the parties have not specified to the contrary, and where the point of valuation is at the wellhead, it is only logical and equitable to assess the royalty owner with the costs incurred downstream of the point of valuation which add value to the product. It is not difficult to understand that the value of sour gas, which is basically unusable in its natural state, is less than the value of sweet gas.

Id.; cf. Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 240 (5th Cir. 1984) (noting that it is "an expensive proposition to convert the raw gas into marketable sweet gas").

[398]. Matlock, supra note 97, § 9.06[1], at 9-39 ("The implied covenant to market has never required a producer to sell gas at a distant market when there was a market at the wellhead.").

[399]. Anderson, Calculating Freight, supra note 189, § 10.02[2], at 339 n.31.

[400]. See supra text accompanying notes 233-38, 263-88 (discussing the decisions in Wood and Rogers).

[401]. See Lansdown, Marketable Condition Rule, supra note 28, at 705 n.173 (arguing that "if a party is purchasing the sour gas it is clearly marketable"); see also West v. Alpar Res., Inc., 298 N.W.2d 484, 493 (N.D. 1980) (Pederson, J., concurring) (arguing that sour gas at the wellhead has a market value).

[402]. This is equally true for crude oil. Heavier crude oil is generally less desirable than lighter crude oil. Conine, Crude Oil Royalty Valuation, supra note 7, § 18.04[2][a], at 18-27. That fact, however, does not mean that heavier crude oil is unmarketable at the wellhead. On the contrary, the oil market expressly recognizes the differences in the weight--or "gravity"--of various grades of crude oil. Williams et al., supra note 129, § 12.04[3], at 12-21 n.52. Accordingly, oil producers will commonly adjust their prices at the wellhead if their oil production is heavier than the preferred gravity. This price adjustment is known as a "gravity price differential." Conine, Crude Oil Royalty Valuation, supra note 7, § 18.04[2][a], at 18-27. While producers may have to adjust their prices on heavier crude oil, the oil may nonetheless be in a marketable condition at the wellhead. See Williams et al., supra note 129, § 12.04[3], 12-21 & n.52 (noting that there is a market for different grades of crude oil).

[403]. "Wet gas" is "[n]atural gas containing liquid hydrocarbons in solution, which may be removed by a reduction of temperature and pressure." Howard R. Williams & Charles J. Meyers, Manual of Oil and Gas Terms 1214 (9th ed. 1994).

[404]. The "residue gas" is the remaining gas, primarily methane, that the processing facility does not extract from the gas stream to manufacture NGLs. "The amount of residue gas that leaves the plant is less than the amount of raw gas that enters the plant as a result of the liquefiable hydrocarbons being extracted from the raw gas." Carter v. Exxon Corp., 842 S.W.2d 393, 396 (Tex. App.--Eastland 1992, writ denied).

[405]. See supra text accompanying note 126 (describing the workback methodology for royalty valuation).

[406]. See Carter, 842 S.W.2d at 397 (interpreting the significance of the words "at the well" in the royalty clause and concluding that their inclusion "specifies that royalties are owed for gas that is produced in its natural state, not on the components of the gas that are later extracted.... Market value is to be calculated the instant the gas is produced from the reservoir."); see also Sowell v. Natural Gas Pipeline Co. of Am., 789 F.2d 1151, 1158 (5th Cir. 1986) (holding that the royalty owners were "not entitled to royalties for liquids that condense after the gas is metered"); Barby v. Cabot Corp., 465 F.2d 11, 15 (10th Cir. 1972) (holding that royalty was not payable on the end products after extraction); Phillips Petroleum Co. v. Record, 146 F.2d 485, 486 (5th Cir. 1944) (holding that a lessee did not owe royalty on manufactured products); Irvin, supra note 54, § 18.05[5], at 18-68 to -70 (discussing Carter and Barby when a lessee engages in downstream activities); cf. Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-15 (recognizing that lessees historically have not had the duty to bear the costs of extracting NGLs from a wet gas stream).

[407]. See Petron Dev. Co. v. Wash. County Bd. of Equalization, 91 P.3d 408, 412 (Colo. App. 2003) (defining "processing" as preparing oil for market, which changes its physical characteristics), aff'd, 109 P.3d 146 (Colo. 2005).

[408]. See Carter, 842 S.W.2d at 395 (explaining the process of manufacturing NGLs).

[409]. See Tooley & Tooley, supra note 77, §§ 21.05[3][d]-[e], at 21-29 to -30 (explaining processing and treating wet gas); see also Mountain Fuel Supply Co. v. United States, 449 F.2d 816, 822 (10th Cir. 1971) (providing the steps in the process of separating water and hydrocarbons from gas).

[410]. See Lomex Corp. v. McBryde, 696 S.W.2d 200, 203 (Tex. App.--San Antonio 1985, no writ) (holding that a marketable product rule does not require that a producer pay royalties on yellowcake slurry that it manufactured from raw uranium, and observing that "the royalty is to be paid out of the oil, gas or other minerals produced and not out of its value after it had been processed into some other product of a higher value").

[411]. 3 Kuntz, 1989 ed., supra note 1, § 40.5, at 351.

[412]. See Anderson, Part 2, supra note 166, at 653-54 (recognizing that the extraction of NGLs and gasoline from wet gas "is a step beyond the exploration and production segment of the industry"); Anderson, New Implied Marketplace Covenant, supra note 174, at 13A-15 (recognizing that "lessees should not carry the full burden of extracting valuable natural gas liquids from a 'wet' gas stream"); see also Raynes, supra note 194, at 1210 (agreeing that the first marketable product rule "does not justify imposing on the lessee the costs of refining or processing the product, unless an intention to do so is revealed by the lease"). States that have enacted statutes adopting variations of the first marketable product doctrine, like Wyoming and Nevada, have statutorily concluded that processing is not a production activity. See, e.g., Nev. Rev. Stat. § 522.115 (2003) (specifying that the definition of costs of production does not include the processing of gas); Wyo. Stat. Ann. § 30-5-304 (2003) (defining costs of production as not including the processing of gas); see also Tooley & Tooley, supra note 77, § 21.05[3][d], at 21-29 (classifying processing as a "step beyond the production obligations of a lessee").

[413]. See Pierce, Incorporating a Century, supra note 30, at 821 (describing the processing activities that enhance the value of gas); Tooley & Tooley, supra note 77, § 21.05[3][d], at 21-29 (distinguishing the act of production from the act of processing). Processing is commonly, but not always, a profitable activity. "[T]he value of the unprocessed gas stream is generally less than the value of the extracted gas liquids and the resulting residue gas." Pierce, Incorporating a Century, supra note 30, at 821 n.129. However, "[p]rices for natural gas and NGL[s] frequently move independently of one another." Pearson, supra note 389, at 1-16. When gas prices increase relative to NGL prices, the processing profit margin may disappear, depending upon the costs of processing. See Pierce, Incorporating a Century, supra note 30, at 821 n.129 (outlining factors that affect the profitability of processing).

[414]. Anderson, Calculating Freight, supra note 189, at 345.

[415]. Kramer & Pearson, supra note 81, at 794; see also supra text accompanying notes 102-03 (delineating when the implied covenant to market begins).

[416]. See Sowell v. Natural Gas Pipeline Co. of Am., 604 F. Supp. 371, 380 (N.D. Tex. 1985) (holding that there is no obligation to pay royalties from the sale of downstream liquids), aff'd, 789 F.2d 1151 (5th Cir. 1986). Because Cypress Lakes entered into a "market value" lease (as opposed to a "proceeds" lease) with Silverlake, it arguably had no duty to market its production at all, but rather only a duty to pay Silverlake royalties based on the market value of the production. In other words, even if Cypress Lakes had failed to market its production, it still could have paid royalties to Silverlake on the basis of the "value" of its production, which it potentially could have calculated from other comparable sales. See Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 373 (Tex. 2001) (distinguishing market-value royalty from an amount-realized royalty).

[417]. If the implied covenant to market required a lessee like Cypress Lakes to create products other than those that existed in the gas stream at the wellhead, the implied covenant to market would beg the question: "Just how far does the implied covenant go?" See Danciger Oil & Refineries, Inc. v. Hamill Drilling Co., 141 Tex. 153, 171 S.W.2d 321, 323 (1943) (considering whether the implied covenant includes refinement, and posing the troublesome question: "Which of the products must be refined, and which need not be refined? ... Moreover, if some of the products are to be refined, to what fineness are they to be refined?").

[418]. See Anderson, Part 2, supra note 166, at 653-54, 692 (stating, "wet gas is generally marketable").

[419]. See supra text accompanying notes 371-72 (discussing Professors Kuntz's and Anderson's explanation of the purpose of the first marketable product doctrine).

[420]. This hypothetical assumes that DG sold hydrogen sulfide to a third party purchaser. The result of this hypothetical would be different if DG processed its hydrogen sulfide to produce elemental sulfur, which it then sold to a third party purchaser. In that event, the result would likely depend on whether DG's lease with Audrey contained a "sulfur clause" specifically describing the manner in which DG must pay royalties on sulfur. See Kramer, Royalty Interest, supra note 8, at 480

(discussing cases addressing whether royalties should be paid based on a gas royalty clause or a sulfur royalty clause). If DG's lease contained no sulfur clause, DG might validly argue that it owes no royalties separately on elemental sulfur--a product that arguably did not exist in the gas stream at the wellhead--but rather owes royalties only on its gas production at the location where its gas first became marketable. Id.; cf. Scott Paper Co. v. Taslog, Inc., 638 F.2d 790, 799 (5th Cir. Unit B Mar. 1981) (concluding that sulfur royalties may be "extrapolated by deducting from the sales revenue of the sulphur extracted from the gas the cost of transmission, processing, and a reasonable return on investment").

[421]. See supra text accompanying notes 110-14 (discussing the lessee's standard of care under the implied covenant to market).

[422]. See Lowe, Defining the Royalty Obligation, supra note 40, at 260 ("The lessee has a duty to act on or near the lease to make production possible to take advantage of a market but has no duty to act away from the lease to create a market."); Matlock, supra note 97, § 9.03[1], at 9-12 ("[T]he lessee is not required to conduct operations beyond the point where they will be profitable to him, even if they will be profitable to the lessor."); see also Kretni Dev. Co. v. Consol. Oil Corp., 74 F.2d 497, 500 (10th Cir. 1934) (declining to find a lessee's duty to provide ninety miles of pipe line facility to reach a market); Armstrong v. Skelly Oil Co., 55 F.2d 1066, 1068 (5th Cir. 1932) (finding that the lessees were not obligated to build a gas treatment plant).

[423]. Cf. Taslog, Inc., 638 F.2d at 799 (observing that hydrogen sulfide and other impurities in the gas stream are not readily marketable "unless there is a commercial user of the product in the vicinity"). Some royalty owners have argued that, if a lessee could hypothetically have sold a product at a downstream location, it must pay royalties on the hypothetical price that it arguably may have earned on selling the product. This argument produces absurd and inequitable results. See Boomgaarden, supra note 9, at 7-21 (highlighting "[t]he potential inequities of taking the marketable product rule to [the] extreme").

[424]. Barby v. Cabot Corp., 465 F.2d 11, 14 (10th Cir. 1972).

[425]. See supra text accompanying notes 396-402 (discussing the proper royalties on production that is marketable at the wellhead).