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Chapter 6

The Royalty Value Theorem and the Legal Calculus of Post-Extraction Costs

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Synopsis

§ 6.01. Why There Will Never Be Peace – Under the Oil and Gas Lease.

[1] — The Royalty Value Theorem.

Royalty disputes are the product of the "royalty value theorem"[1] which states:

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[1] In 2000 I served as the impartial opening act for a two-day slugfest on royalty valuation issues between oil and gas producers and the United States Department of Interior's Minerals Management Service (MMS). I tried to capture the essence of the parties' differences with a single principle on which all parties could agree. My efforts

> 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.[2]

Therefore, lessors will pursue courses of action designed to obtain 1/8th[3] of X+ instead of 1/8th of X. Because any additional royalty paid to the lessor will come out of the lessee's interest, the lessee will object to paying royalty on X+ instead of X, unless required by the express terms of the oil and gas lease. The royalty-based lease relationship, by its very nature, is the classic *un*cooperative venture where each response to changed circumstances creates a new opportunity to pursue royalty value theorem strategies.[4]

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resulted in the royalty value theorem. David E. Pierce, "What's Behind the Valuation Controversy Anyway?" *Special Institute on Federal & Indian Oil and Gas Royalty Valuation and Management*, Rocky Mountain Mineral Law Foundation and the Minerals Management Service (April 17, 2000)[hereinafter *Valuation Controversy*].

2 *Valuation Controversy* at 1.

3 For illustration purposes I will assume the negotiated royalty is 1/8th, realizing that today lessors frequently negotiate for royalties in excess of 1/8th.

4 One decade ago, speaking at the Eastern Mineral Law Annual Institute, I addressed changing circumstances in the natural gas industry that would create new opportunities for royalty disputes. David E. Pierce, "Royalty Calculation in a Restructured Gas Market," 13 *E. Min. L. Inst.* 13-1 (1993)[hereinafter *Royalty Calculation*]. Ten years later, many of the predictions I offered are now the subject of a state supreme court opinion. For example, in discussing the Kansas/Texas approach to defining "market value" I made the following observation:

> As with any limitation on risk, there is a price to pay. Under a market value royalty clause, the lessor gives up any claim to benefits the lessee may receive when the lessee assumes market risks by entering into longer-term contracts or sales transactions beyond the initial marketing point. As the *Vela* line of cases demonstrates, the lessee's market value risk can be substantial in a gas market of escalating prices. However, in a gas market of de-escalating prices, the lessee should be able to reap the full benefit of its contract risk assumption. For example, if the lessee has a contract authorizing collection of NGPA prices of $3.19/Mcf, the lessee should be able to pay, under a market value royalty clause, royalty calculated from a properly adjusted spot price. For example, using the July 1992 spot price for sales at a designated sales point on Texas Eastern's pipeline, the price for royalty valuation should not exceed $1.45. This would seem to be the

[2] — Lessor and Lessee Responses to the Royalty Value Theorem.

When the royalty value theorem is applied to gas royalty, the lessor will seek to maximize its position by pursuing the following three strategies:

> correct approach in states following the *Vela* approach to market value royalty.

Royalty Calculation at 18-28 to 18-29.

The Texas Supreme Court addressed this issue *in Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368 (Tex. 2001), and held the lessee properly paid their lessor using the lower current gas market values instead of the substantially higher contract price actually being paid to the lessee by its gas purchaser. Regarding the implied covenant to market, I also noted: "Arguably, the *implied* covenant [under a market value royalty clause], with regard to price, never operates because an *express* covenant, the royalty clause, states the basis for payment – current market value." *Royalty Calculation* at 18-47. This concept was also affirmed by the court in *Yzaguirre*.

In addressing potential strategies for each party, I offered the following advice to lessors:

> When the lease is silent regarding deductible costs, the lessor's best approach may be to argue that the lessee has an implied covenant to make the gas 'marketable.' Under contemporary marketing scenarios, the lessor would argue that 'marketable' includes all costs associated with moving the gas to the first marketing point where willing buyers can interact with willing sellers. In many instances, this would impose on the lessee all costs of producing, gathering, compressing, treating, and transporting to the first available marketing point on a pipeline.

Royalty Calculation at 18-49.

Some variation of this theme has been adopted by Oklahoma (Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203 ((Okla. 1998)), TXO Production Corp. v. Comm'rs of the Land Office, 903 P.2d 259 ((Okla. 1994)), and Wood v. TXO Production Corp., 854 P.2d 880 ((Okla. 1992)); Kansas (Sternberger v. Marathon Oil Co., 894 P.2d 788 ((Kan. 1995)); and Colorado (Garman v. Conoco, Inc., 886 P.2d 652 ((Colo. 1994)) and Rogers v. Westerman Farm Co., 29 P.3d 887 ((Colo. 2001)).

Not all of my predictions have proven accurate. For example, in 1992 I stated:

> Where the oil and gas lease clearly identifies the point at which "market value" or "proceeds" are to be determined, the lease terms will control. For example, if the lease provides for payment of the market value or proceeds "at the well" or "at the mouth of the well," and the actual sale of production takes place at some point beyond the wellhead, reasonable costs incurred by the lessee beyond the wellhead will be deductible in calculating royalty.

Royalty Calculation at 18-34.

The Colorado Supreme Court, even with its expanded location-based marketable product rule, refused to give any effect to the "at the well" language contained in the oil and gas leases. Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001).

(1) establishing the location for making the royalty valuation as far downstream from the wellhead as possible; (2) obtaining the benefit of any post-extraction aggregation,[5] packaging,[6] and marketing[7] undertaken by the lessee, an affiliate of the lessee, or a non-affiliated entity; (3) avoiding as many deductions as possible from the aggregated, packaged, and marketed, downstream gas value. Lessees will want the location for calculating royalty as close to the point of extraction as possible and before adding value to the gas through aggregation, packaging, and downstream marketing. Their goal is to pay royalty only on the value of the gas at the time and location where it is extracted. If downstream values, or aggregated or packaged values, are used to begin the royalty calculation, lessees will want to subtract any value added to the gas prior to calculating royalty.

Lessors often use an implied covenant analysis to first push the initial royalty valuation point as far downstream from the wellhead as possible.[8]

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5 "Aggregation" would include any value added to the gas by being combined with a larger volume of gas. For example, 100 Mcf/day from a single lease would typically be worth more when sold as part of an aggregated supply consisting of 100,000 Mcf/day. The difference in value represents the risk and cost required for someone to acquire many 100 Mcf/day gas supplies until an adequate volume is under contract to supply certain markets. Aggregation will typically occur at a location downstream from the leased premises. Aggregation, as the term is used in this chapter, does not include the transportation required to move the gas from the wellhead to the ultimate aggregation point.

6 "Packaging" includes any activity that adds what I will call "obligation value" to the gas. The "obligation," and the "value," added to the gas come from the contractual commitments the seller makes to the buyer in conjunction with the gas sale. For example, the seller may commit to have a certain volume of gas available to the buyer while their contract is in effect. Packaging accounts for the special needs of a buyer and the risks it desires to shift to their seller.

7 "Marketing" in this context is the process of identifying potential gas buyers, designing the packaging required to attract their business, and arranging the intermediate transactions necessary to effect the physical acquisition, movement, and delivery of the gas to each buyer.

8 *E.g.*, Rogers v. Westerman Farm Co., 29 P.3d 887, 912 (Colo. 2001)("we . . . adopt a definition of marketability to include both physical condition such that the gas would be acceptable for sale in a commercial market, *and a location-based assessment*, such that

This will be followed by a somewhat parallel legal analysis to limit the deduction of costs from the downstream value to calculate the royalty due. Lessees typically respond focusing on the express terms of the oil and gas lease that contemplate royalty valuations at the well or on the leased premises.[9]

However, when the lessee does not sell the gas at the wellhead, the parties will often focus on whether costs can be deducted from a downstream sale to arrive at a wellhead value. In such cases the major issue is: what is the issue?

§ 6.02. Are Courts Addressing the Right Question?

[1] — Entitlement or Evidence?

If you ask the wrong question, you are likely to arrive at the wrong answer. When addressing deduction of costs, the way the question is posed

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it would be saleable in a commercial marketplace.")(emphasis added) and TXO Production Corp. v. Commissioners of the Land Office, 903 P.2d 259, 263 (Okla. 1994)("the costs for compression, dehydration and gathering are not chargeable to Commissioners because such processes are necessary to make the product marketable under the implied covenant to market.").

9 For example, in *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887 (Mich. Ct. App. 1997), the court held:

> We adopt the interpretation of 'at the well(head)' as used in these cases because we believe that it better conforms with the parties' intent as gleaned from the contractual language. . . . In this case the use of the language 'gross proceeds at the wellhead' by the parties appears meaningless in isolation because the gas is not sold at the wellhead and, thus, there are no proceeds at the wellhead. However, if the term is understood to identify the location at which the gas is valued for purposes of calculating a lessor's royalties, then the language "at the wellhead' becomes clearer and has a logical purpose in the contract. In construing 'wellhead' thusly – in a manner that seeks to accord reasonable meaning to the plain language of the contract – we believe that it necessarily follows that to determine the royalty valuation, postproduction costs must be subtracted from the sales price of the gas where it is subsequently marketed.

565 N.W.2d at 188-89.

can often determine whether the cost issue is one of "entitlement" or merely one of "evidence." Counsel representing lessors will pose the question as: (1) can the lessee deduct a cost from the gas sales revenue before calculating the royalty? and (2) if deductible, is the cost reasonable? Lessees, however, should not be addressing the question as framed by the lessor. Instead, the lessee should pose the question as: does the amount of money paid to the lessor comply with the terms of the oil and gas lease? The difference is subtle but fundamental. Under the lessor's framing of the question, the issue is determining the lessor's *entitlement* to royalty, based upon the lessee's *entitlement* to make deductions. Under the lessee's framing of the question, the issue is *evidentiary*: what evidence can I use to determine whether what was paid was too little, too much, or just right?

[2] — Professor Anderson's Entitlement Analysis.

Professor Owen Anderson has written a series of articles relying, in part, upon an entitlement analysis to protect lessor interests. I will use his analysis to illustrate the lessor's case; I will offer a critique of his analysis to make the lessee's case. In his article, "Calculating Royalty: 'Costs' Subsequent to Production — 'Figures don't lie, but . . . .,'"[10] Professor Anderson summarizes his analysis of the deduction of cost issue as follows:

> In order to obtain a market, the lessee is not obligated to invest in post-production facilities at its own expense unless the lessee is able to make a reasonable profit.[11] However, to avoid overreaching by the lessee in the calculation of royalty payments, the lessee may deduct only reasonable and necessary direct costs, not to exceed actual costs, and in no case should a lessee be allowed to 'zero out' the wellhead value of gas. In other words, the lessor must receive a reasonable royalty on marketed gas measured in the context that royalty is part of the consideration for the lease. In assuring the lessor a reasonable royalty, all profit from a post-production facility must be derived from the lessee's working interest and not from

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[10] Owen L. Anderson, "Calculating Royalty: 'Costs' Subsequent to Production – 'Figures don't lie, but . . . ,'" 33 *Washburn L. J.* 591 (1994)[hereinafter *Figures Don't Lie*].

[11] Although not the focus of Professor Anderson's article, this raises the question whether, under the implied covenant to market, the lessee would be obligated to "invest

> the lessor's royalty share. Thus, a return on investment 'cost' should be eliminated from the work-back royalty calculation or — at the very least — be limited to a cost-of-money charge, such as the prime rate of interest.[12]

Professor Anderson's analysis is influenced by the potential for lessee "overreaching."[13] It appears he is concerned with the lessee's side of 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 *the lessee to minimize the value* — in this case by overstating downstream costs to calculate upstream values. Of course, at the same time there will be a tendency by *the lessor to maximize the value* — in this case by understating, or avoiding altogether, downstream costs. Professor Anderson's solution to this state of affairs is to simply deny categorically certain costs[14] and "in the interest of equity" allow costs to be deducted only to the extent the result will be a "reasonable royalty" to the lessor.[15]

[3] — An Evidentiary Analysis.

Professor Anderson's approach seeks to substitute a "reasonable royalty" analysis for the terms of the oil and gas lease. Arguably, as with any contract, each party's protection against overreaching under the oil and gas lease are the terms of the contract. This is where framing the issue becomes so important. If the question is: what was the market value of the gas at the well from July 1, 1996 through July 1, 2000, the goal will be to

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in post-production facilities" whenever it would be profitable. Would the lessee evaluate the profitability of constructing a treatment plant based solely upon the volumes of gas attributable to its lessor's oil and gas lease? If not, does this mean the lessee also has the implied obligation to seek out gas processing agreements from other lessees in the area so it can fulfill its implied lease obligations to a single lessor?

12 *Figures Don't Lie* at 637.

13 "[T]his approach is necessary 'in the interest of equity' . . . to keep the lessee from overreaching." *Figures Don't Lie* at 637.

14 "Thus, a return on investment 'cost' should be eliminated from the work-back royalty calculation or — at the very least — be limited to a cost-of-money charge, such as the prime rate of interest." *Figures Don't Lie* at 637.

15 In a subsequent chapter presented at the 20th Annual EMLF Institute, Professor Anderson qualified his analysis noting: "I continue to adhere to these views with respect

examine all relevant evidence to ascertain the market value. The deduction of costs from downstream values is an evidentiary issue: what *value* should be disregarded to arrive at the *value* of the gas at the wellhead? However, suppose the question is: from the lessee's $2.00/Mcf downstream sales proceeds, can it deduct $0.50/Mcf as a processing charge, even though $0.05 of the $0.50 represents the lessee's profit associated with its processing business? There are two problems with this statement of the question. First, it assumes the lessor is entitled to any benefit from the downstream value. Second, it assumes the lessor is entitled to the downstream value free of certain costs of generating the downstream value. Professor Anderson assumes in his work-back analyses the lessor will receive the downstream value and the lessee will only be able to deduct costs it can defend as "reasonable," and in any event will not be entitled to the $0.05/Mcf profit figure.[16] In determining what are "reasonable" costs, Professor Anderson would require the parties to battle through a complex maze of accounting issues.

I have suggested that in cases where royalty is a fraction of the market value at the well, the lessor is entitled to no value associated with downstream activities.[17] Therefore, if the market value of the gas at the

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to these wellhead-value jurisdictions. Part of my purpose here is to consider whether this same view is appropriate in a marketable-product jurisdiction." Owen L. Anderson, "Royalty Valuation: Calculating Freight in a Marketable-Product Jurisdiction," 20 *Energy & Min. L. Inst.* 331, 335 (2000)[hereinafter "*Calculating Freight*"]. His ultimate conclusions are as follows: "As in a wellhead-value jurisdiction, 'costs' should not include a profit rate of return, either before or after income taxes, in a marketable-product jurisdiction. I would, however, allow a cost-of-money charge in a marketable-product jurisdiction and allow other reasonable indirect costs, such as overhead." *Calculating Freight* at 357.

16 Although he might be willing to allow the lessee to recover a "cost-of-money charge, such as the prime rate of interest," (*Figures Don't Lie* at 637), Professor Anderson would also limit costs to those classified as "direct actual costs." *Id.* at 638. Therefore, the lessee would have to bear all costs that cannot be classified as "direct," as opposed to "indirect," and apparently will have the burden of proving what is considered a direct actual cost. In a marketable-product jurisdiction, he would allow "reasonable indirect costs, such as overhead." *Calculating Freight* at 357.

17 "Under a market value royalty clause, the lessor gives up any claim to benefits the lessee may receive when the lessee assumes market risks by entering into longer-term contracts or sales transactions beyond the initial marketing point." *Royalty Calculation* at 18-28.

well is $1.40/Mcf and the $2.00/Mcf downstream value minus the full $0.50/Mcf processing charge is $1.50/Mcf, the lessor is entitled to 1/8th of $1.40, not 1/8th of $1.50. It appears Professor Anderson would require payment of 1/8th of $1.55 ($2.00 - $0.45). By stating the question as an issue of entitlement, the lessee will be paying a royalty on an additional $0.10 to $0.15/Mcf in value. If the issue is ascertaining value at the wellhead, the downstream events are relevant only to the extent they assist in determining the wellhead value of the gas.

Where lessees use a work-back calculation to determine the wellhead value of gas, if they only deduct the reasonable, allowable costs from the downstream value, they will in most cases be overpaying their royalty owner. The overpayment results from the royalty the lessor is paid on the net enhanced value of the gas at the downstream location. Using our prior example, applying Professor Anderson's cost analysis the lessor will be receiving 1/8th of $1.55 instead of 1/8th of $1.40. What accounts for the $0.15/Mcf difference in value? It must reflect the value-added component of the additional risk, capital, effort, and skill associated with the downstream processing business. Professor Anderson would consider this "profit" which the lessee can earn only on its "share" of the production while the 1/8th associated with the lessor's "share" of production must be paid to the lessor.[18]

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[18] Although the term "share" is used, it should be remembered that under the vast majority of oil and gas leases the lessor will not, at any time, own any part of the produced gas. Their entitlement will be to a contractually-defined sum of money, not a share of the gas. The lessee will own all the gas as it is produced. In *Greenshields v. Warren Petroleum Corp.*, 284 F.2d 61,67 (10th Cir. 1957), *cert. denied*, 355 U.S. 907 (1957), the court discussed the gas ownership issue in rejecting the lessor's conversion claim against its lessee, stating:

> Whether or not title passes upon the occurrence of production must be determined from the language of the lease . . . . In the Producers 88 lease here under consideration, it is provided that the lessor shall receive a portion of the gross *proceeds* at the market rate of all gas, contrasting with the provision for his receipt of one-eighth *part of all oil produced*. It is well settled that the provision concerning the payment for gas operates to divest the lessor of his right to obtain title in himself by reduction to possession and that thereafter his claim must be based upon the contract with the one

Professor Anderson's approach to the issue gives the lessor a preferred status with regard to assets the lessee may own or operate in a separate downstream business. If the lessor is only entitled to the value of gas "at the well," then it should be of no consequence whether downstream facilities are owned and operated by their lessee or by a third party.[19] If the lessee owns the facility, whatever the lessee charges its customers for facility services should be used to determine the value of those services. If the lessee is pricing its services correctly to the public, the charge will include profit, overhead, and all the other cost, risk, and profit elements an independent entrepreneur will seek to recover from its customers. The only time it may be necessary to do a cost analysis is when the lessee is not providing the service to third parties and therefore transactions do not exist to define the "value" of the service. Even then the value of the service might be better determined considering what others charge for similar services. As with the other calculations, this too is an evidentiary issue.

It must be remembered that lessors are not co-owners of downstream enterprises, nor are they in any sort of joint venture with their lessees. 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. The complexity associated with Professor Anderson's analysis arises from his unwillingness to de-link the lessor from the lessee when the gas is not sold at the wellhead. This linkage, and the resulting complexity, are not necessary; nor is the linkage consistent with the oil and gas lease. The express terms of the oil and gas lease initiate the de-linkage of lessor and lessee the moment the gas is produced. 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

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> to whom he has granted that right. His claim can only be for a payment in money and not for the product itself.

248 F.2d at 67.

19 Of course, if the facility is owned by the lessee, the lessor will want to ensure they are being treated no worse than the parties who are purchasing services from the facility.

a royalty obligation. Often the obligation to pay royalty will be triggered when the gas is "used" by the lessee instead of sold; in these situations the royalty measure will typically be the "market value at the well" of the gas used. At that point, what the lessee does with the gas is irrelevant[20] to the lessor's royalty entitlement – they are entitled to 1/8th of the market value, determined at the well, of the gas used.

Although Professor Anderson's analysis follows an entitlement theory, his primary goal is to protect the lessor from the risk of lessee overreaching. In those cases where Professor Anderson perceives the risk of overreaching to be minimal, he actually follows an evidentiary approach. For example, he would not disturb royalty calculated using an actual wellhead sale,[21] nor would he question marketing costs paid to unaffiliated third parties.[22] Therefore, Professor Anderson's "entitlement" analysis is really not founded on the express or implied terms of the oil and gas lease. Instead, it is an analysis he would use whenever the available evidence does not measure up to his level of reliability.

This last point suggests another issue that can be impacted by the way the issue is framed: who has the burden of proof? When the issue is phrased in terms of whether a cost can be charged against the lessor, and if so, whether it is reasonable, many courts place the burden of proof on the lessee.[23] If the issue is "the market value of gas at the wellhead on a

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20 One exception would be if the gas was "used" for lease operations, in which case most lease forms would exclude the gas from any royalty obligation.

21 "While this latter approach [wellhead sale] would not take into account downstream profits, royalty valuation would be based on *more objective and direct evidence* of market value, thus assuring the royalty owner of a fairer valuation." *Calculating Freight* at 337, n.26 (emphasis added).

22 "On the other hand, if the lessee paid an arm's-length equivalent fee to a third party to perform post-wellhead, pre-sale services, the lessee should be permitted to deduct the lessor's proportionate share of these third-party charges from royalty because that is the lessee's actual costs." *Calculating Freight* at 340, n.43.

23 In *Wellman v. Energy Resources, Inc.*, 557 S.E.2d 254, 265 (W. Va. 2001), the court placed on the lessee the burden of proving that the cost was incurred and that it was reasonable.

particular date" a court may be more inclined to put the burden of proof on the lessor challenging the amount paid as a breach of their contract.[24]

Once the parties appreciate the importance of how the question is framed, they will resort to various substantive theories to resolve the issue as framed. The lessor will place its primary reliance on the implied covenant to market; the lessee will rely on the express terms of the oil and gas lease.

§ 6.03. The Competing Post-Extraction Cost Analyses.

[1] — The Implied Covenant Approach.

The implied covenant "marketable product" theory probably began with Professor Merrill's observations in his 1940 treatise titled "The Law Relating to Covenants Implied in Oil and Gas Leases."[25] Professor Merrill articulates his theory as follows:

> 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.[26]

The first court to rely on this statement was the Kansas Supreme Court in a pair of cases where the lessee was held to have improperly deducted compression costs under leases providing for a royalty of "1/8th of the proceeds of the sale thereof at the mouth of the well."[27] The key element

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[24] Even when the issue is stated in the context of the implied covenant to market the Kansas Supreme Court has clearly placed the burden of proof on the lessor challenging the lessee's actions. Smith v. Amoco Production Co., 31 P.3d 255, 273 (Kan. 2001).

[25] Maurice H. Merrill, *The Law Relating to Covenants Implied in Oil and Gas Leases* (2d ed. 1940)[hereinafter *Merrill*]. Professor Merrill published the first edition of this work in 1926.

[26] *Merrill* at § 85, at 214-15.

[27] Gilmore v. Superior Oil Co., 388 P.2d 602, 607 (Kan. 1964); Schupbach v. Continental Oil Co., 394 P.2d 1, 4 (Kan. 1964). The precedential value of the *Gilmore* and *Schupbach* cases is limited because the court apparently held the lease language was ambiguous and then proceeded in each case to interpret the lease against the lessee and in favor of the lessor. Under the Kansas Supreme Court's later opinion in *Sternberger v. Marathon Oil Co.*, 894 P.2d 788 (Kan. 1995), it would appear compression costs could be deductible when associated with enhancing an already "marketable product."

of Professor Merrill's analysis is a finding the gas "is unmerchantable in its natural form."[28]

Professor Kuntz also endorses a marketable product analysis in his treatise, stating:

> It is submitted that the acts which constitute production have not ceased until 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 paid in money.[29]

As with Professor Merrill's "merchantable" analysis, the key to Professor Kuntz's analysis is determining when a "marketable product" has been produced. However, 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. Courts to date have not placed any importance on the origin of the interpretive challenge and have instead focused on the question: what is a "marketable product?" Lessors have been effective at couching the analysis in terms of an implied covenant to market.

Professor Kuntz's definition of "marketable product" has also been put to effective use by lessors. Professor Kuntz defines marketability in terms of whether there is a "commercial market" for the gas in its natural or current state, noting: "If there is a commercial market, then a marketable product has been produced . . . . If there is no commercial market for the raw gas, the lessee's responsibilities theoretically have not ended, and the lessee should bear the cost of making the gas marketable."[30] The first cases to adopt a marketable product analysis confined the inquiry to the quality of the gas and whether it could be sold when produced, even though there

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28 *Merrill*, at § 85, at 214.

29 3 Eugene Kuntz, *A Treatise on the Law of Oil and Gas* § 40.5, at 351 (1989)[hereinafter *Kuntz*].

30 *Kuntz*, § 40.5, at 351.

was no "market" for the gas at the point of production.[31] The Colorado Supreme Court, in addition to focusing on the "quality" issue, has also focused on the nature of the "commercial market" by adding a "location" component to the analysis.[32] In *Rogers v. Westerman Farm Co.*, the Colorado Supreme Court held:

> 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.[33]

The potential scope of the location element of the test is revealed by the court's observation: "It may be, for all intents and purposes, that gas has reached the first-marketable product status when it is in the physical condition and location to enter the pipeline."[34] This means that in many cases the "quality" of the gas will not matter because the quality element will be subsumed by the location element. For example, if the commercial marketplace is defined as an interstate pipeline, the quality of the gas will be dictated by what is required to deliver the gas into the interstate pipeline.

In 1996, as the initial group of "marketable product" decisions were issued by Colorado,[35] Kansas,[36] and Oklahoma,[37] I observed, under the heading "The 'Marketable Product' Game," the following:

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31 The court that most clearly articulates this approach is the Kansas Supreme Court in *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 799 (Kan. 1995)("Contrary to SKROA's argument, however, there is no evidence in this case that the gas produced by Marathon was not marketable at the mouth of the well other than the lack of a purchaser at that location.").

32 Rogers v. Westerman Farm Co., 29 P.3d 887, 905 (Colo. 2001).

33 *Id.*

34 *Id.*

35 Garman v. Conoco, Inc., 886 P.2d 652 (Colo. 1994).

36 Sternberger v. Marathon Oil Co., 894 P.2d 788 (Kan. 1995).

37 TXO Production Corp. v. Commissioners of the Land Office, 903 P.2d 259 (Okla. 1994), and Wood v. TXO Production Corp., 854 P.2d 880 (Okla. 1992).

> In *Sternberger* the court stated: 'The lessee has the duty to produce a marketable product, and the lessee alone bears the expense in making the product marketable.' The notoriously malleable concept of 'marketable product,' when joined with general notions of lessee implied marketing obligations, can be used as a false analytical tool to arrive at about any conclusion a court desires.[38]

Perhaps the greatest weakness of the marketable product approach, whether using the Merrill implied covenant analysis or the Kuntz "production" analysis, is the marketability issue in each case must be addressed as a question of fact.[39] This means that under the *Rogers* analysis a lessee cannot safely sell its gas at the wellhead in an arm's-length transaction for the best price available at the time it is produced. Years later, when the volumes and numbers are sufficient to support a contingent fee arrangement, the lessee's wellhead marketing will be challenged because it was not done at the required "commercial marketplace." The lessor's attorney will seek to show that had the lessee incurred gathering compression, and other costs to move the gas to a downstream marketing point, they could have netted, for example, an extra $0.03/MMBtu in revenue — which after years of production now amounts to something worth going to court over. Although there is no issue concerning the , "quality" of the gas and that it was in fact marketed, the lessor will note that the "commercial marketplace" issue has not been decided, and it is an issue of fact for a jury to consider.

Although commentators, most notably Professor Anderson,[40] excoriate the Colorado Supreme Court's decision in *Rogers*, it is really the next

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38 David E. Pierce, "Developments in Nonregulatory Oil and Gas Law: The Continuing Search for Analytical Foundations," 47 *Inst. on Oil & Gas Law and Tax'n*, 1-1, 1-43 to 1-44 (1996).

39 *E.g.*, Rogers v. Westerman Farm Co., 29 P.3d 887, 905 (Colo. 2001). The most ardent advocate for the question of fact approach has been Professor Anderson. Owen L. Anderson, "Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 2 Should Courts Contemplate the Forest or Dissect Each Tree?" 37 *Nat. Resources J.* 611, 642 (1997).

40 Owen L. Anderson, "Views on the Royalty Obligation in Today's Oil & Gas Market, 2001: A Royalty Odyssey," 53 *Inst. on Oil & Gas Law and Tax'n* 2-1 (2002).

logical[41] step for lessors to pursue under a marketable product analysis — and the royalty value theorem. I set out the contours for a *Rogers* approach in 1992 when I wrote the following for this organization's 13th Annual Institute:

> *When the lease is silent regarding deductible costs*, the lessor's best approach may be to argue that the lessee has an implied covenant to make the gas 'marketable.' Under contemporary marketing scenarios, the lessor would argue that 'marketable' includes all costs associated with moving the gas to the first marketing point where willing buyers can interact with willing sellers. In many instances, this would impose on the lessee all costs of producing, gathering, compressing, treating, and transporting to the first available marketing point on a pipeline.[42]

The key to success for the lessor's approach is establishing that the "lease is silent regarding deductible costs." In *Sternberger* the lessor was not successful because the Kansas Supreme Court recognized that "at the well" was relevant language regarding deductible costs;[43]

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[41] In a recent article I preface the *Rogers* case with the heading: "The Colorado Marketable Product Rule: An Illogical Application of a Logical Rule or the Logical Application of an Illogical Rule?" David E. Pierce, "Recent Developments in Nonregulatory Oil and Gas Law: Unfinished Business," 53 *Inst. on Oil & Gas Law and Tax'n* 1-1 (2002)[hereinafter *Unfinished Business*].

[42] *Royalty Calculation* at 18-49 (*emphasis added*).

[43] Sternberger v. Marathon Oil Co., 894 P.2d 788, 794, 796 (Kan. 1995). The court made the following observations concerning the "at the well" language:

> Sternberger correctly states that ambiguities in an oil and gas lease are to be construed in favor of the lessor. [citing *Gilmore v. Superior Oil Co.*] . . . . Here, however, the lease is not ambiguous. The lease's silence on the issue of post-production deductions does not make the lease ambiguous. The lease clearly specifies that royalties are to be paid based on 'market price at the well.' 894 P.2d at 794.

. . . .

Scott, *Voshell*, and *Molter* are dispositive of the issue in this case. 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. 894 P.2d at 796.

In *Rogers* the Colorado Supreme Court interpreted the phrase "at the well" out of existence.[44] Perhaps the best explanation for these differences in approach are the differences in each court's jurisprudential agenda.[45] The Kansas Supreme Court is clearly following a traditional interpretive agenda, recognizing that any implied covenant to market is *implied in fact* to give full effect to the express covenants in the parties' contract.[46] In contrast, the Colorado Supreme Court appears to be pursuing an agenda designed to correct perceived injustices in the oil and gas lease, by pursuing an *implied in law* approach.[47] The major competing theory for addressing

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[44] In *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 896 (Colo. 2001), the court stated:

> We next review the 'at the well' language to determine if, at a minimum, it addresses the allocation of transportation costs. We conclude that it does not. Instead, in order to determine allocation of costs where the lease language is silent, we must look to the implied covenant to market, and thus, whether the gas is marketable.

The court even applies this "silent" analysis with its expanded commercial marketplace requirement which considers the *location* of a market. "At the well" seems to be pretty "loud" when it comes to location.

[45] *See generally* David E. Pierce, "Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market," 48 *Rocky Mtn. Min. L. Inst.* 10-1 (2002).

[46] Smith v. Amoco Production Co., 31 P.3d 255, 264 (Kan. 2001)("According to the lessors, the lease covenants here are implied in fact, not in law, and are, thus, an integral part of the written lease. We agree.").

[47] In a previous article I commented on *Rogers* as follows:

> In what appears to be more akin to unconscionability analysis instead of contract interpretation, the court in *Rogers* reveals its general hostility toward the oil and gas lease as written, and oil and gas lessees in general. The following observations made by the court, as a prelude to its implied covenant analysis, reveal why it departs from the parties' contract on a mission to achieve 'justice' and 'prevent unjust enrichment':
>
> 1. '[L]essees, to avoid alerting lessors to their motives, have intentionally used 'at the well' language to avoid directly stating their objectives in sharing costs.'
>
> 2. '[I]n interpreting leases like those in this case, we are mindful of the generally accepted rule that oil and gas leases are strictly construed against the lessee in favor of the lessor.'

post-extraction cost issues focuses on the express terms of the lease, as an issue of law, instead of relying upon a fact-sensitive implied covenant analysis.

[2] — The Express Covenant Approach.

The express covenant approach focuses on the language of the lease as the guide for defining the legal calculus of post-extraction costs. This can occur at many levels. For example, if the operative clause is "market value" at a particular location, it may be unnecessary to address the post-extraction cost issue. Instead, the issue is identifying the evidence that will define market value.[48] If the operative clause is "proceeds" at a particular location, the parties may have to deal with adjusting the receipt of proceeds at a location downstream from the designated proceeds location. This presents the post-extraction cost issue in a work-back context. Whether the measure is market value or proceeds, if a location for making the calculation is not specified, the court will have to consider all the other terms of the

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3. 'This rule [strict construction against lessee] is generally based on the recognition that the bargaining power between lessor and lessee is similar to that historically found between an insurance company and its customers. . . . Thus, the parties are in similar unequal positions.'

4. '[L]essors are not usually familiar with the law related to oil and gas leases, while lessees, through experience drafting and litigating leases, generally are.'

Therefore, the court holds the express terms of the oil and gas lease offer no insight into how royalties should be calculated because, as the court assumes: all lessees use leases that hide the operative language from their lessors, lessors have no bargaining power, and lessors don't know the law. The court's response is not to declare the oil and gas lease unconscionable, but rather to 'interpret' a better deal for the lessor using the implied covenant to market and a marketable product analysis. The precise scope of the court's marketable product rule will be governed by what the court perceives is necessary to prevent unjust enrichment under its view of the oil and gas lease and the parties to the lease. This is that implied-in-law rationale for implied covenants that Professor Merrill advocated which apparently had no explicit judicial support until the *Rogers* decision. *Unfinished Business*, at 1-10.

48 *See supra* § 6.02 [1].

lease,[49] and any relevant industry custom and usage,[50] to fix the location. Typically this will result in an "at the well" location.[51] All of this assumes, however, that the lease does not have other express language which specifies how post-extraction costs will be handled.[52]

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49 If the lessee's other lease rights and obligations are generally defined with reference to the leased land, a court may conclude the leased premises is the appropriate location for defining the lessee's marketing obligations. For example, the granting clause defines the lessee's development rights by limiting them to the "leased land." Production to perpetuate the lease under the habendum clause is defined by the "leased land." The commencement, completion, dry hole, cessation, and shut-in royalty clauses are defined by action, or inaction, on the "leased land." The lessor's right to royalty is defined by production that is extracted and measured from the "leased land." It should not be surprising to the lessor that the lessee would expect its royalty rights and obligations to be similarly defined at the "leased land." *See generally* David E. Pierce, "The Missing Link in Royalty Analysis: An Essay on Resolving Value-Based Royalty Disputes," 5 *Texas Wesleyan L. Rev.* 185 (1999).

50 For example, in *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 326 (Kan. 1995), the court, quoting from its opinion in *Matzen v. Hugoton Production Co.*, 321 P.2d 576 (1958), noted: "'When plaintiff's leases were executed it was the established custom and practice in the field to measure, determine the price, and pay royalty at the wellhead for gas produced.'" The *Matzen* royalty clause provided for a royalty of "one-eighth of the proceeds from the sale of gas . . . ."

51 If the lease specifies a valuation "at the well" the express covenant approach will give effect to this language. For example, in *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887, 894 (Mich. Ct. App. 1997), the court reasoned:

> We adopt the interpretation of 'at the well(head)' as used in these cases because we believe that it better conforms with the parties' intent as gleaned from the contractual language. . . . In this case, the use of the language 'gross proceeds at the wellhead' by the parties appears meaningless in isolation because the gas is not sold at the wellhead and, thus, there are no proceeds at the wellhead. However, if the term is understood to identify the location at which the gas is valued for purposes of calculating a lessor's royalties, then the language 'at the wellhead' becomes clearer and has a logical purpose in the contract. In construing 'wellhead' thusly – in a manner that seeks to accord reasonable meaning to the plain language of the contract – we believe that it necessarily follows that to determine the royalty valuation, postproduction costs must be subtracted from the sales price of the gas where it is subsequently marketed.

52 Even when the lease contains express language prohibiting the deduction of costs, it must be considered with the other terms of the lease. For example, assume the lease provides for a royalty measured by the "market value at the well" for gas sold off the

The express covenant approach generally begins with the basic premise that royalty calculations should be made at the location where the oil and gas are produced. Unless the lease states otherwise, marketing downstream of the leased land is not contemplated. This means the court must find within the lease document, or an amending division order or pooling agreement, expression of an intent to require the lessee to seek off-lease markets. In effect, the "commercial marketplace" under the express covenant approach is defined to be "on the leased premises" as a matter of law.[53] This establishes the base for considering post-extraction cost issues.

The express covenant approach seeks to define the scope of "production" activities as a matter of law. Generally production would include all activities necessary to bring oil or gas to the surface.[54] The

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leased premises. The lessor negotiates for, and obtains, the following clause: "Provided, however, that there shall be no deductions from the value of Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation or other matter to market such gas." The gas is sold off the leased premises for proceeds which reflect the gas having been dehydrated, compressed, and transported to the point of sale. Can the lessee deduct those costs in calculating "market value at the well?" The Texas Supreme Court held the "Provided" clause did not change the lessee's basic obligation to pay royalty based upon "market value at the well." Therefore, transportation expenses could be deducted in an effort to define the "market value at the well" for royalty purposes. Heritage Resources, Inc. v. NationsBank, 939 S.W.2d 118, 120, 123 (Tex. 1996).

[53] *Kuntz*, § 40.4(d), at 331 ("With respect to the situs of the market, many leases make specific provision for payment on the basis of market value or market price at the well. In instances where the lease has not so provided, it has been held or assumed that the gas royalty is to be paid on the basis of value or price of gas on the market at the well."); 3 Patrick H. Martin and Bruce M. Kramer, *Williams & Meyers on Oil and Gas Law* § 644, at 598 (2001)("By the express provisions of the lease or other agreement, a royalty or other nonoperating interest may be payable 'at the well.' In other instances the nonoperating interest may be described as a share of the 'value' or 'market value' of the production; in these cases 'value' or 'market value' is usually measured 'at the well.'"); 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. and Tax'n* 181, 184 (1953)("Particularly pertinent to the topic under discussion is the almost universally recognized rule that the lessee's marketing obligation is measured *at the well head*. In the absence of specific phraseology in the lease compelling a contrary conclusion, royalty with respect to marketed gas is computed and paid on the basis of its market value *at the well*.").

[54] Professor Richard C. Maxwell has theorized that production ends when the lessee brings gas to the surface. Therefore, any expenses associated with bringing gas to the

factual inquiry would be limited to determining whether the expense was required to physically extract the gas from the ground. If required to extract gas from the ground, it is a "production" expense, if not, it is a "post-production" expense. Courts could create some bright-line matter-of-law rules for certain expenses, such as wellhead metering expenses, classifying them as either production or post-production in all situations. Other expenses may have to be left to a factual inquiry. For example, merely classifying the activity as "compression" may not answer the pertinent question. If the compression is used to increase line pressure from a gathering system so the produced gas can flow into a higher-pressure pipeline system, this would not be viewed as a production facility. However, "compression" associated with a wellhead compressor used to place a vacuum on the wellbore may be a "production" facility.

Another rationale advanced for a production-based cost analysis is that the lessee's obligation is to pay royalty on the "gas" that is produced instead of the lessee's "investment" in a compressor or pipeline, or a "fee" the lessee pays a third party for compression and transportation services. When the lessee is required to pay a royalty on downstream values, without adjusting downstream values for investments or fees incurred to gather, compress, dehydrate, treat, process, aggregate, package, and market the gas, the lessee is paying a royalty on non-gas items. As the court in *Schroeder v. Terra Energy, Ltd.* observed:

> [T]o accede to plaintiffs' interpretation of 'gross proceeds at the wellhead' would be to require defendant to pay royalties to plaintiffs, based not only on the value of the gas at the wellhead, but also upon the costs that defendant has incurred to prepare the gas for, and transport the gas to, market. Thus, plaintiffs' royalties would be increased merely as a function of defendant's own efforts to enhance the value of the gas through postproduction investments

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surface are "production" expenses borne by the lessee and any expenses incurred after gas is brought to the surface can be deducted by the lessee prior to calculating royalty. Richard C. Maxwell, "Oil and Gas Royalties – A Percentage of What?," 34 *Rocky Mtn. Min. L. Inst.* 15-1, 15-15 to 15-16 (1989).

that it has exclusively underwritten. We simply do not believe that such an interpretation of the disputed term is more compatible with either the plain language of the agreement or with the logical expectations of the parties to the agreement.[55]

§ 6.04. Lessor and Lessee Strategies Looking Forward.

[1] — Existing Leases.

The Colorado Supreme Court's opinion in *Rogers* has pointed the way for lessors seeking to push the royalty value theorem to the limit using the implied covenant to market. The Texas Supreme Court's opinion in *Yzaguirre* provides the lessee's express covenant response. States that have not addressed the issue will likely shop for answers within the analytical confines of *Rogers* and *Yzaguirre*. Although the West Virginia Supreme Court did not have the benefit of *Rogers* or *Yzaguirre* when it decided *Wellman v. Energy Resources, Inc.*,[56] the court reviewed the existing body of marketable product and express covenant cases to embrace its version of a marketable product analysis. The facts the court had to work with: Energy Resources, Inc. received $2.22/Mcf from Mountaineer Gas Company for gas produced from the Wellman lease and Energy Resources paid the Wellman's 1/8th of $0.87/Mcf as royalty. The royalty clause required payment of "1/8th of the proceeds from the sale of gas as such at the mouth of the well. . . ."[57] For all the court knew, Mountaineer may have been taking delivery of the gas "at the mouth of the well . . . ." Energy Resources offered no evidence on the matter, other than to "contend that it was entitled to deduct certain expenses from the amounts received from Mountaineer Gas Company before calculating the Wellmans' royalty."[58]

The court was unimpressed and seemed to direct its disappointment with Energy Resources toward the post-extraction cost theory it selected. The court first noted that "a distinguishing characteristic of such a [landowner's] royalty interest is that it is not chargeable with any of the

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55 Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App. 1997).

56 Wellman v. Energy Resources, Inc., 557 S.E.2d 254 (W. Va. 2001).

57 *Id.* at 263.

58 *Id.*

costs of discovery and production."[59] This statement is consistent with a "production" versus "post-production" analysis, but the court continues, stating:

> In spite of this, there 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,[60] 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 the costs of discovery and production, these expenses have been referred to as 'post-production expenses.'[61]

Note the negative spin the court places on the deduction of costs by using terms such as an "attempt" to deduct and to "escape" the obligation to pay costs. Although Energy Resources may have been attempting to escape paying its lessor what it was entitled to, I believe the court let the facts prompt it to select a rule it felt would be more protective of the royalty owner. Under the circumstances, the court felt the Wellmans needed some protection from its lessee. However, the same level of protection could have been provided under what it characterizes as the Texas/Louisiana "post-production" rule as would be obtained under the Kansas, Oklahoma, or *Garman*-based Colorado marketable product rules – which the court ultimately endorses.[62]

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59 *Id.* at 264-65.

60 This is not a recent development. When oil or gas is not sold at the well, lessees have been deducting transportation expenses since the gas industry began. This fact was carefully developed by the Kansas Supreme Court in *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 795 (Kan. 1995)(The court cited with approval and relied heavily upon *Scott v. Steinberger*, a 1923 case, where the lessee was held to have properly deducted $0.07/Mcf as a transportation charge from the $0.15/Mcf in sales proceeds under a lease obligating the lessee to pay a royalty on "one-eighth of all gas produced and marketed.").

61 Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 264 (W. Va. 2001)(emphasis added).

62 The court followed its negative spin discussion with the following:

> Two states, Texas and Louisiana, have recognized that a lessee may properly charge a lessor with a pro rata share of such 'post-production' (as opposed

The court therefore adopts a marketable product analysis without ever comparing the relative strengths and weaknesses of each approach. Instead, the court seeks to bolster its selection of the marketable product analysis by reasoning: (1) West Virginia recognizes an implied covenant to market; (2) such a covenant imposes a "duty" on the lessee; and (3) relying upon the analysis in *Garman*,[63] the court concludes that "historically the lessee has had to bear the cost of complying with his covenants under the lease." [64]

The ultimate rule the court articulates, however, goes far beyond the marketable product approach adopted by Colorado,[65] Kansas, and

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> to production or development) costs. On the other hand, it appears that a number of other states have rejected this position where a lease, such as the ones in the present case, calls for the payment of royalties on the basis of what the lessee receives from the sale of oil and gas.

Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 264 (W. Va. 2001).

63 Although the court notes that *Garman* cites Professor Kuntz for this proposition, Professor Kuntz made it clear that just because the lessee has a "duty" to do something does not mean the lessee must bear all the expense associated with performing the duty. In the words of Professor Kuntz:

> Although it is not difficult to reason from the presence of a general duty on the part of the lessee to market the produce to the conclusion that the lessee has authority to dispose of royalty gas on behalf of the lessor, *it is considerably more difficult to reason from such general duty to a conclusion as to which party or parties must bear any added expense* which might be incident to preparing the gas for market. . . .
>
> Much of the difficulty can be avoided if it is recognized that there 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. There is, however, no reason to impose on the lessee the costs of refining or processing the product, unless an intent to do so is revealed by the lease. It is submitted that the acts which constitute production have not ceased until a marketable product has been obtained.

Kuntz, § 40.5, at 350-51 (emphasis added). The court concludes that "historically the lessee has had to bear the cost of complying with his covenants under the lease." Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 264-65 (W. Va. 2001).

64 Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 264-65 (W. Va. 2001).

65 Applying the *Garman* principles instead of the *Rogers* analysis that radically revises the *Garman* principles.

Oklahoma. The court in *Wellman* states the rule as follows: "[T]his Court concludes that if 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."[66] Arguably this is a broader rule than even the *Rogers* approach because it does not distinguish between expenses incurred before or after a marketable product exists. Under all versions of the marketable product analyses costs incurred in "marketing" and "transporting" the product "to the point of sale" are deductible once a marketable product has been created. Since the court purported to adopt the Kansas, Oklahoma, and *Garman*/Colorado versions of the marketable product rule,[67] I think what the court meant to hold is that until a marketable product is produced, none of the listed expenses are deductible. However, once a marketable product is created, expenses that enhance the marketable product are deductible when the downstream value is used to calculate the lessor's royalty. Presumably the court also adopted the quality-based approach, followed by Kansas, Oklahoma, and pre-*Rogers* Colorado, for determining when gas is a marketable product.

The other major issue not resolved by *Wellman* concerns the impact express lease language will have on its marketable product analysis. Although the lease at issue contained "at the mouth of the well" language,[68] the court was careful to note the issue had not been raised by the lessee because it offered no evidence that it actually incurred any costs.[69] The court, however, makes it clear that the language can be significant, stating:

> Although this Court believes that the language of the leases in the present case indicating that the 'proceeds' shall be from the 'sale of gas as such at the mouth of the well where gas . . . is found'

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66 Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 265 (W. Va. 2001).

67 "This Court 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." Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 265 (W. Va. 2001).

68 *Id.* at 263.

69 *Id.* at 265.

> might be language indicating 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, whether that was actually the intent and the effect of the language of the lease is moot because Energy Resources, Inc., introduced no evidence whatsoever to show that the costs were actually incurred or that they were reasonable.[70]

If the court gives effect to this express lease language, it would further aline itself with the Kansas and Oklahoma[71] versions of the marketable product rule.

Another astute observation by the court in *Wellman* was that the analysis might be different when the express terms of the lease call for a royalty measured by market value. In a footnote the court stated: "Where leases call for the payment of royalties based on the value of oil or gas produced, and sold directly, the Court perceives that there are possibly different issues, and they are excluded from this discussion."[72] The "different issues" would be determining whether the lessee has paid "market value." Under many leases a royalty is triggered without a sale. For example, under the lease in *Wellman* any sort of sale of the gas would trigger a royalty based, at least in part, on the "proceeds from the sale . . . ."[73] However, if the gas is not sold, but rather is "used by Lessee for the manufacture of gasoline or any other product," the royalty will be calculated using an objective standard measured by "the market value of such gas at the mouth of the well . . . ."[74] Therefore, regardless of the proceeds the lessee obtains from its use of the gas, whether a net loss or net gain, the lessor's royalty will be the same. The lessor gets

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70 *Id.*

71 At least the most current statement of the Oklahoma rule in *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203 (Okla. 1998).

72 Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 264, n.3 (W. Va. 2001).

73 *Id.* at 257-58. Without regard for where the gas is "sold" it would trigger a "proceeds" royalty.

74 Wellman v. Energy Resources, Inc., 557 S.E.2d 254, 257-58 (W. Va. 2001).

paid on the value of the gas at the time, location, and condition it is produced.[75]

In those states that have already adopted a version of the marketable product analysis, lessors will be busy trying to get courts in their state to adopt the Colorado approach.[76] I predict that most of the lessee efforts in marketable product states will be working through the applicable analyses to establish that their gas was indeed a marketable product when produced. However, before giving-in to the implied covenant analysis, lessees will again seek to limit the scope of the implied by that which is expressed. Express lease terms such as "market value" and "at the well" must be evaluated in each case, at least in those states where the implied covenant to market is implied in fact as opposed to implied in law. Where the covenant is implied in fact the court will need to first interpret the oil and gas lease to ascertain what it addresses, and what it does not. With regard to the areas the lease fails to address, the implied covenant must be fashioned keeping in mind it is supposed to be an extension of the expressed terms in the particular lease at issue. The "facts" which direct the content of the implied-in-fact covenant come from the oil and gas lease at issue. Therefore, if the parties expressly agreed to facts "a," "b," and "c" in their oil and gas lease, can we safely conclude they would have intended their agreement to include implied obligation "d"? To date courts have assumed there is a generic implied obligation that exists without regard to the terms of the underlying contract the covenant is supposed to be advancing.[77]

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[75] Note that when the market value royalty measure is applied to gas that is "used" instead of being sold, it is conceptually difficult to argue that market value in this context was merely intended to mean a downstream value less downstream costs to reflect a wellhead value.

[76] Cases are already moving through the Kansas and Oklahoma court systems where lessors are seeking to add the Colorado commercial marketplace requirement to the state's existing quality-based marketable product rule. *E.g.*, Coulter v. Anadarko Petroleum Corp., 26th Judicial District Court, Stevens County, Kansas, Case No. 98-CV-40 (trial to the court, decision pending); Bridenstine v. Kaiser-Francis Oil Company, District Court of Texas County, Oklahoma, Case No. CJ-2000-1 (jury verdict for plaintiffs, appeal pending).

[77] An exception to this statement would be the implied-in-fact analysis applied by the Texas Supreme Court. *E.g.*, HECI Exploration Co. v. Neel, 982 S.W.2d 881 (Tex. 1998).

Another major line of lessee inquiry in marketable product states will be: what happened to the prudent operator rule when defining the implied covenant to market? It is revealing that marketable product states, purporting to rely upon the implied covenant to market, don't ever talk about the hallmark of implied covenant law: the prudent operator rule. In other implied covenant contexts courts have consulted the "prudent operator" to not only define the duty but to also measure compliance with the duty. If we are really applying implied covenant law, the process should ascertain what a prudent operator would do under the circumstances. Once this is done, the lessee's actions would be measured by how a prudent operator would have responded to the situation. As lessees press this line of inquiry, courts will start to realize they skipped the prudent operator concept altogether and merely adopted a new obligation as a matter of law – while justifying it using implied covenant concepts.

Not all courts have ignored the prudent operator rule when applying the implied covenant to market. Although the Kansas Supreme Court seemed to overlook the concept in *Sternberger*, the court applied it splendidly in *Smith v. Amoco Production Co.*[78] The court in *Smith* had to evaluate the lessee's decision to trigger the gas contract renegotiation process created by the Federal Energy Regulatory Commission (FERC) in FERC Order No. 451.[79] Amoco was the seller under a 1950 gas contract with Williams Natural Gas Company that covered 600,000 dedicated acres, included multiple price vintages of gas, continued for the life of the leases, and contained no minimum take obligation, other than a ratable take requirement.[80] The situation facing Amoco when Order 451 took effect on January 23, 1987 was thus: (1) Amoco had lessors entitled under the Williams gas contract to below market prices for "old" gas and other lessors

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78 Smith v. Amoco Production Co., 31 P.3d 255 (Kan. 2001).

79 Ceiling Prices; Old Gas Pricing Structure, Order No. 451, F.E.R.C. Reg. Preambles 1986-1990 ¶ 30,701 (1986), 51 *Fed. Reg.* 22,168 (June 18, 1986), modified, Order No. 451-A, F.E.R.C. Reg. Preambles ¶ 30,720 (1986), 51 *Fed. Reg.* 46,762 (Dec. 24, 1986), modified further, Order No. 451-B, F.E.R.C. Reg. Preambles ¶ 30,748 (1987), 52 *Fed. Reg.* 21,669 (June 9, 1987).

80 Smith v. Amoco Production Co., 31 P.3d 255, 259-60 (Kan. 2001).

entitled to above market prices for "incentive" vintage gas; (2) Amoco had it within its power to trigger the Order 451 process that could cause the "old" and "incentive" vintage gas to become subject to market pricing, thereby raising the prices received by "old" gas lessors while lowering the prices received by "incentive" gas lessors; (3) Williams, however, could effectively lock-in the "old" gas by agreeing to pay the specified Order 451 price while forcing Amoco to either accept the new Order 451 price for "incentive" gas or suffer its release from the contract, which would result in even lower market prices available at the time; and (4) Williams could effectively use all the Amoco gas as a reserve supply because it only had a ratable take obligation under their contract, which meant if Williams took no gas from the field, it could refuse to take any gas under the Amoco contract.[81]

Amoco, realizing Williams had the upper hand, avoided triggering Order 451 and instead sought to renegotiate its contract with Williams. This negotiation process, which included various trips to courts across the country, continued from the Summer of 1986 through June 8, 1989.[82] On June 8, 1989 Amoco triggered Order 451. Amoco's action, and Williams' response, had the effect of raising some "old" gas prices from $0.579/MMBtu to $2.864/MMBtu.[83] Following Amoco's triggering of Order 451, Williams ceased taking gas under the contract, except for some minimal amounts to maintain leases in effect and to meet Williams' winter peak demands.[84] From 1989 through 1991, Amoco sought to renegotiate the Williams contract resulting in a 1990 short-term release and in August 1991 a long-term release extending through December 1992, when all gas would be deregulated under the Natural Gas Wellhead Decontrol Act.[85] Under the releases Amoco was allowed to sell the gas to other purchasers at market

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81 *Id.*

82 *Id.* at 261.

83 *Id.*

84 *Id.*

85 *Id.* at 262.

prices, which were considerably lower than the Williams contract "incentive" prices. Amoco was sued by the Youngren class of "old" gas royalty owners asserting Amoco should have triggered Order 451 sooner to raise their "old" gas prices. Amoco was also sued by the Smith class of "incentive" gas royalty owners asserting Amoco should not have triggered Order 451 at all because it would reduce their "incentive" gas prices.[86]

The plaintiffs in *Smith* first tried to pose the implied covenant to market issue as an issue of law by asserting Amoco had the "duty to obtain the best price in gas contracting."[87] The court rejected this invitation and instead adopted a duty "to market the produced minerals at reasonable terms within a reasonable time following production."[88] This places the issue in the proper prudent operator frame of reference. Applying the prudent operator to the factual context of Order 451 and the Williams contract, the court observed:

> We do not feel that renegotiating under FERC's deregulation policy should expose Amoco as a common lessee to automatic liability under its implied covenant to market as a reasonably prudent producer.[89] We believe that the better analysis involves a fact-specific approach for evaluating the Smith Class' claim that Amoco's actions under Order 451 breached the implied covenant to market. We reason that the implied covenant to market is to be enforced with a consideration given to the purpose of Order 451. . . .
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> Whether Amoco has performed its duty under the implied covenant to market here is a question of fact. . . . The decision to invoke Order 451 and enter into renegotiation rests with Amoco, which was in a position to evaluate the potential benefits and losses for its

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86 *Id.* at 262-63. The Youngren litigation was settled.

87 Smith v. Amoco Production Co., 31 P.3d 255, 270 (Kan. 2001). The plaintiffs even went so far as to contend: "it is illogical to say that the expressed royalty provisions override the lessee's implied duties. They reason that setting aside a duty to obtain the best price possible eliminates the duty of good faith and fair dealing and the implied covenant to market." 31 P.3d at 270.

88 Smith v. Amoco Production Co., 31 P.3d 255, 271 (Kan. 2001).

89 This sort of "automatic" liability was what the lessors were seeking by using their "best price" matter-of-law analysis.

lessors. The basic obligation to act as a reasonably prudent operator remains.[90]

In remanding the case to the district court, the Kansas Supreme Court restates the fundamental principles applicable to resolving an implied marketing covenant claim:

1. Amoco's conduct will be evaluated by considering 'what an experienced operator of ordinary prudence would do under the same or similar circumstances, having due regard for the interests of both [lessor and lessee]. . . .'
2. Evaluation of Amoco's conduct under the prudent operator standard is a question of fact.
3. The district court must apply the prudent operator standard to the facts as they existed at the time Amoco took the action complained of.
4. The lessors have the burden of proof.
5. The facts are not contested, and Amoco's actions are not patently imprudent; thus, expert testimony will be required to establish a breach of the covenants alleged.[91]

There is no reason why this same analysis should not be applied in the marketable product cases which are merely an application of the implied covenant to market.

[2] — Future Leases.

It is in the best interests of both lessors and lessees to minimize the influence of the royalty value theorem on their lease agreements. The case law makes it clear how best to avoid royalty value theorem issues: first, select an objective basis for determining the *base royalty value*; second, select the *location at which the base royalty value will be ascertained*; and third, select the *location at which volume measurements will be made* for royalty purposes. In my 1992 presentation to this Foundation I concluded that because of the new marketing scenarios, where "proceeds" associated with a particular lease are often impossible to identify, some form of "market

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90 Smith v. Amoco Production Co., 31 P.3d 255, 273 (Kan. 2001).

91 *Id.* at 273-74.

value" base royalty value should be used in new leases. I noted: "For new leases, a market value royalty clause, requiring current market values based upon location, quality, and adjusted spot prices, would seem to be the most workable approach."[92] In a subsequent article, titled "Drafting Royalty Clauses,"[93] I explore this topic in greater detail and conclude the best approach is to use a recognized index for determining the base royalty value[94] and then negotiate a discount to reflect the approximate difference in value at the point of production compared to the index valuation location.[95] All volume and quality measurements would be made at the wellhead and royalty paid on the volumes produced at the lease.

To illustrate the process, assume there is a recognized index price at "the Baker Plant Interconnect on the East Coast Pipeline," which we will call the "Index." The Index has been available for seven years. The lessor and lessee, as part of their lease negotiation process, note that the Index prices have historically been, on average, about 20 percent more than prices obtained for production in the general area where the leased land is located. The lessee proposes a royalty based upon production measured at the wellhead, times an amount equal to 75 percent of the Index price. The lessor counters with a proposal of an amount equal to 100 percent of the Index price. The ideal outcome would be if the lessor and lessee agree to a base royalty value equal to 83.5 percent of the Index price, which would be their best advance approximation of a wellhead value. Any negotiation concerning the total value of the lessor's royalty should focus on the size of the royalty fraction, as opposed to manipulating their approximation of wellhead values. This would allow the lessee to use the discounted Index price for other purposes, such as calculation of severance taxes.[96] Assume for the month of April 2002 the Index price was $2.00/MMBtu and 10,000

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92 *Royalty Calculation* at 18-52.

93 David E. Pierce, *Drafting Royalty Clauses*, 18th Annual Advanced Oil, Gas and Mineral Law Course 12-1 (State Bar of Texas 2000).

94 This would include a mechanism to address failure of the index, with the ultimate back-up being a market value measure. *Drafting Royalty Clauses* at 10-11.

95 Although I use a percentage discount, it could also be based upon a set sum of money. However, the parties should avoid formulas, such as "less gathering costs," which require them to address the same deduction of cost issues that create problems under existing lease forms.

96 *Drafting Royalty Clauses* at 8-9.

MMBtus were produced from the leased land during the month of April. The parties have agreed to a 1/5th royalty to be calculated as "1/5th of an amount of money calculated by taking 80 percent of the Index price multiplied by the total wellhead gas production volume for the calendar month." Therefore, the lessor's royalty will be calculated by first taking the $2.00 index price times 80 percent for an adjusted price of $1.60. This amount would be multiplied by the total gas volumes measured at the wellhead: $1.60 x 10,000 = $16,000. The final calculation would be multiplying the $16,000 figure by the royalty fraction of 1/5th for a total royalty of $3,200.

The major benefit of this approach is it is objective and readily verifiable by all parties involved. The lessor can effectively audit their royalty payments on a monthly basis once they know the total volumes produced, the index price, and any deductions for taxes. The lessee can do whatever they want with the gas once it is extracted. The only remaining area of potential dispute between the parties, and the only remaining potential role for the implied covenant to market, would focus on the *rate* of production. This is the *volume*, as opposed to *value*, component of the implied covenant to market. The lessor wants to ensure the lessee maximizes production from the well to maximize the lessor's royalty income.[97]

With the advent of recognized location-based index pricing for natural gas,[98] it is now possible to contractually select how royalty will be calculated in the future. Once negotiations over the royalty fraction, the index, and the location discount are completed, each party knows what they "won" and "lost" in the contracting process. The goal in drafting the lease is to clearly express these negotiation victories and defeats so the battle is not fought again on another front: typically a court house.[99]

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97 *Drafting Royalty Clauses*, at 10.

98 For my article on *Drafting Royalty Clauses* I went so far as to create an index using trading information from the New York Mercantile Exchange. After that exercise, I have concluded such an approach introduces an unnecessary level of complexity in the drafting process because the basic valuation goals can be more easily achieved by using localized pipeline indices for the base royalty value.

99 Equally important is providing an objective basis for calculating royalty so each party, during the life of the contract, will know they are receiving that which they "won" under the contract.