Chapter 7

Royalty Administration
in Volatile Energy Markets

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§ 7.01. Introduction.

In the Byrd’s 1960s hit My Back Pages (the quasi title song on the album Younger than Yesterday), Roger McGuinn sang one of Bob Dylan’s more puzzling refrains, “Ah, but I was so much older then, I’m younger than that now.” ¹ Although these lyrics clearly present a chronological challenge, in comparing the natural gas market to that existing in the mid-70s, it would appear the concept of Younger than Yesterday may be an appropriate description. The natural gas markets then were stable, with very limited options and opportunities, adjectives which might describe older, more mature persons. Yet now, the natural gas markets are less stable and more chaotic, presenting producers with a significantly wider variety of gas marketing options.

¹ “My Back Pages” recorded first by Bob Dylan, Another Side of Bob Dylan, released May 1, 1964, Columbia.
Not surprisingly, these options are accompanied by risks. One of the risks is legal exposure to the royalty owner. For if we consider the calculation of royalties as an equation, the key components of that equation are the royalty provisions of the lease and the value of the production or the proceeds received from the sale of that production. Even though royalty provisions have remained relatively constant, the volatility of the gas markets and of the marketing options have made the royalty calculation equally volatile. The numerous cases dealing with this degree of volatility have on balance neither been consistent nor particularly helpful. This chapter describes the old stable market and legal principles formulated in that time, compares the marketing options then available to those existing under current market conditions, and the problems for a lessee attempting to apply those principles to current reality, and somewhat tentatively makes suggestions on charting a course through the minefield so created.

For much of the time since the enactment of the Natural Gas Act (NGA) in 1938, and perhaps more importantly since the United States Supreme Court determined in *Phillips Petroleum Co. v. Wisconsin* that the Natural Gas Act applied to gas sales by producers in interstate commerce and required such sales to be at just and reasonable rates, gas markets have been dominated by interstate pipelines. The interstate pipelines purchased the gas at or near the wellhead, at low prices regulated under the “just and reasonable” standard by the Federal Power Commission (FPC), the predecessor to the Federal Energy Regulatory Commission (FERC). Gas once dedicated to interstate commerce by a sale to an interstate commerce could not be freed from the burden of that dedication without a formal abandonment order issued by the FPC, which required a finding that such abandonment was permitted by “public convenience and necessity.”

The pipelines purchased the gas at the wellhead or central points in the field and transported it to end users, including the local distribution

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companies who sold the gas at retail. The pipelines performed the entire function of purchasing gas and delivering it to end users on a bundled basis, with no other parties realistically having the ability to perform these bundled services. The contracts for the sale of gas in interstate commerce were long term contracts, usually for the life of the leases, with minimal provisions for price increases. The market-based indefinite price escalation clauses (which later were standard in virtually all gas purchase contracts) were then not customarily a part of the gas purchase contracts in interstate commerce, and at one point were even deemed against the public interest.\(^5\) The low “just and reasonable” rates imposed by the NGA through the FPC proved inadequate to encourage drilling necessary to replenish the depleting supplies of natural gas dedicated to the interstate market.

The largely unregulated intrastate market was initially not dissimilar in its contractual provisions, with long term “life of the lease” provisions dominating the market. However, in the mid-to-late 70s, the intrastate market became flexible and presented more attractive prices and terms. The limited supplies of new natural gas production mostly flowed to the intrastate market when a producer had a choice.\(^6\) The interstate market, bound by regulation and low prices, began to be afflicted by shortages. The resulting shortages were manifested in brownouts, and a solution was deemed necessary.

A perhaps overly cynical theory is that all federal policy involving the regulation of natural gas sales and marketing was fashioned to achieve two goals for the densely populated areas of the northeast: 1) plentiful natural gas supplies and 2) cheap prices. Under this theory, the Natural Gas Policy Act of 1978\(^7\) (NGPA) would be considered to have been the result of a realization that in the context of the markets of the late 70s

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\(^6\) Due to the permanence of the dedication to interstate commerce and the adverse effect on the pricing at which production could be sold resulting from such a dedication, it became common in the late seventies and early eighties for farmout agreements and certain leases to prohibit the farmee/lessor from taking any action which could result in production being dedicated to interstate commerce.

both goals could not be achieved. In order to deal with the shortages of natural gas in the interstate market, the NGPA subjected sales of natural gas in both the interstate and intrastate markets to price regulation, with prices payable by all purchasers limited by a complex framework of “maximum lawful prices.” Gas contracts entered into by interstate pipelines after the enactment of the NGPA frequently linked the price payable under those contracts to the maximum lawful prices contained in the NGPA. These NGPA maximum lawful prices proved more than adequate to encourage additional drilling, resulting in abundant supplies in the market. This increase in supplies of natural gas, together with a softening of demand, resulted in lower market prices for natural gas, with the NGPA maximum lawful prices generally exceeding those free market prices. The interstate pipelines were therefore frequently obligated to purchase and deliver to their customers gas at prices in excess of prices at which their customers could purchase gas in the open market. This problem for the local distribution companies (LDCs) and for their customers was dealt with by the FERC by the elimination of the “minimum bill” obligations of the interstate pipelines’ customers, which left the pipelines’ customers free to purchase gas from other suppliers at current market prices.  

This resulted in hardship to the pipelines, which were now contractually committed to purchase gas that they could not sell at economically sustainable prices. Ultimately, this also led to hardships for the producers as most of the above market take or pay contracts that produced a significant part of the revenues on their balance sheets were abrogated or renegotiated, sometimes both, and frequently in that order.

The economic hardship on both sides of the NGPA-motivated gas purchase contracts resulted in a number of bankruptcies in the 1980s. More significantly for our purposes, the fact that the NGPA had actually resulted in contract prices higher than the market value of gas led in part to the enactment of the Natural Gas Wellhead Decontrol Act of 1989,  


\[ \text{9 Pub. L. 101-60, July 26, 1989. 103 Stat 157.} \]
and other events more significant as historical rather than current events.\textsuperscript{10} The culmination of this series of events was FERC Order 636\textsuperscript{11} which largely eliminated the role of the interstate pipelines as bundled suppliers of natural gas to end users, relegating them to suppliers of unbundled services, such as firm and interruptible transportation and storage of gas to any parties desiring such services.

The restructuring of the gas markets by Order 636 created a revolution in natural gas markets, opening up the markets to a variety of players. The functions of pipelines as initial purchasers of gas and ultimate sellers to end users are served by others, with gas now purchased in most situations by independent and affiliated marketers. These marketers frequently serve as suppliers to the LDCs and other traditional pipelines customers, who continue to have need for firm gas supplies with significant seasonal variations in demand. However, the availability of the formerly bundled pipeline services allow producers who have significant supplies of natural gas and substantial balance sheets to compete for these gas sales markets as well. A producer, at least one having significant gas reserves, may have the following marketing options for the sale of gas from a given lease:

(a) a sale at or near the wellhead to a gathering company or intrastate pipeline, with price based on market indices, less a deduction for transportation or other services;

(b) a short term sale to a gas marketer at a nearby point of interconnection with an interstate pipeline based on nominated volumes, with pricing also based on market indices;

(c) a longer term sale of specified minimum volumes to an independent marketer, with prices based on a percentage of the


proceeds received by the purchaser in its resales of the gas, with the percentages varying depending on the volumes delivered; and

(d) a direct sale to LDCs or other end users on a long term basis, for firm volumes, with the delivery point at the city gate where the LDC or end user is located and prices based either on (i) an appropriate spot market index price plus a premium or reservation charge, (ii) a fixed price, or (iii) an index price plus a penalty if takes by the purchaser fall below a specified percentage.

Each of these contractual options present different opportunities, require different commitments of expertise, expenses, effort and financial resources, and each could result in different amounts realized by the lessee. From the standpoint of its own corporate abilities, risk sensitivities and policies, a given lessee may determine which opportunity is in its best interest at a given time. In assessing the risks and benefits of each of these corporate opportunities, the lessee needs to understand its obligations and exposure to its royalty owners as a result of the options presented.

§ 7.02. The Royalty Relationship.

While generally characterized under the laws of most jurisdictions as creating a real property interest (or immovable property in Louisiana\textsuperscript{12}), an oil and gas lease is essentially a contract, providing the lessee to right to explore for and produce oil and gas in exchange for sharing with the lessor a percentage of the oil and gas so produced. The relationship has been described as a “cooperative venture” in which “the lessor contributes the land and the lessee the capital and expertise necessary to develop the minerals for the mutual benefit of both parties.”\textsuperscript{13} The royalty clause establishes the basis on which the lessee shares such mutual benefits with its lessors.

One of the problems facing the lessee is that both the royalty provisions and the early cases interpreting them were shaped by the traditional market

\textsuperscript{12} Louisiana Revised Statutes 31:16.

existing when they were formulated. As Professor John Lowe said in a recent article in the SMU law review:\textsuperscript{14}

A typical lease royalty only has plain meaning in the context of traditional sales in the field; we are doing business in the age of the computer chip with lease forms drafted (and sometimes executed) in the age of the Model A Ford.\textsuperscript{15}

It is not only the lease forms themselves that are problematic. Other lease related matters have contributed to the problem. The implied covenant to market, developed to supplement the relative rights and obligations of the lessor/lessee relationship in the traditional market structure, is being applied with enthusiasm by courts in certain jurisdictions to the marketing arrangements in the restructured gas market. The uncertainties arising from this situation, as well as the significant sums of money at issue, have led to large number of disputes between lessee and lessor.

\section*{\textsection 7.03. Lease Royalty Provisions.}

While a royalty clause can take as many forms as the imagination of a drafter can envision, essentially royalties are calculated either based on the (a) market value or market price of the gas produced or (b) the proceeds or amounts realized from the sale of the gas. A common royalty clause is a combination or hybrid, providing for payment of the royalty percentage of the proceeds if gas is sold at the well, and of the market value of the gas if sold off the leased premises or otherwise used.\textsuperscript{16}

Although the terms market value and market price may be differently defined, in practice they are “practically interchangeable.”\textsuperscript{17}

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\textsuperscript{15} Id. at 253.
\textsuperscript{16} See e.g. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984), which is important for a number of reasons, in which the royalty clause read: “. . . on gas, . . . produced from said land and sold or used. . . . the market value at the well of one/eighth of the gas sold or used; provided, that on gas sold at the wells the royalty shall be one/eight of the amount realized from such sale.”
\textsuperscript{17} 3 Williams, Oil and Gas Law, \textsection 650.2 at n. 23. However, in Shamrock Oil and Gas Corp v. Coffee, 140 F.2d 409, 410-411 (5th Cir. 1944), the court stated that “[m]arket
has been defined as the price property would bring “when offered for sale by one who desires, but is not obligated to sell and bought by one who is under no necessity of buying it.”

Unless the lease provides otherwise, market value has typically been determined at the wellhead.

Having said what determines market value, the next question is when it is to be determined? There are basically two methods. Under one method, initially articulated in the Oklahoma case of Tara Petroleum Corp v. Hughey, the market value of gas is determined at the time the contract for the sale of gas is entered into. The rationale of the Tara rule was based on the traditional market structure, in which frequently the only available market involved sales to interstate pipelines, at fixed prices and with long term dedications. When the sharp increases in the prices of natural gas in the late Seventies and early Eighties resulted in a significant gap between these contract prices and the prices available on the open market, the lessors in the Tara case sought to have their royalties determined on the higher current market prices. However, the court reasoned that inasmuch as the lessee had been obliged by the implied marketing covenant to sell gas into this market and to commit the gas to long term “just and reasonable” contract pricing, it would be unfair to penalize the lessee for complying with its implied marketing covenant by committing the gas to the only market available. Under the Tara rule, a contract entered into in good faith with the best available terms and conditions will determine the market value of the gas committed to that contract. Thus the lessee’s obligations under the royalty clause are in fact linked to the lessee’s rights under its gas purchase contract. States adopting the Tara rule include Louisiana and Arkansas.

price is the price that is actually paid by buyers for the same commodity in the same market. It is not necessarily the same as ‘market value’ or ‘fair market value’ or ‘reasonable worth.’ Price can only be proved by actual transactions.”

18 Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981) at 246.
19 See, e.g., Piney Woods, 726 F.2d 225 (5th Cir.); The Law of Oil and Gas, § 7.4(c) p.354.
21 Henry v. Ballard & Cordell, 418 So. 2d 1334 (La. 1982).
The other method of calculating market value is typically called the *Vela* rule, based on the decision by the Texas Supreme Court in *Texas Oil & Gas Corp v. Vela*. The court in *Vela* focused on “plain terms” of the royalty provisions, which in its view, required that royalty payments be based on market value at time of sale or use of gas. Unlike the rationale in *Tara*, the *Vela* rule views the lessee’s obligations under its gas contract as wholly independent of its lease obligations. States following *Vela* include Kansas, Montana, Mississippi and West Virginia.

The complement of *Vela* is the recent Texas Supreme Court case of *Yzaguirre v. KCS Resources, Inc.*, in which the court applied the principle set forth in *Vela* that a market value royalty provision required payments based on the “prevailing market value at the time of sale” to mean that a lessee should in fact pay royalties based on market value at the time of sale, and not the higher proceeds which the lessee was then receiving under its 1979 gas purchase contract. In reaching its conclusion, the Texas Supreme Court employed much of the same reasoning it had used 33 years previously in *Vela*, noting, as it had in *Vela*, that the parties could have provided for royalties payable on an amount realized basis, but stated: “[i]nstead of doing so, however, they stipulated in plain terms that the lessee would pay one-eighth of the market price at the well of all gas sold or used off the premises. This clearly means the prevailing market price at the time of the sale or use.”

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23 *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866 (Tex. 1968).
27 *Imperial Colliery Co. v. OXY USA Inc.*, 912 F.2d 696 (4th Cir. 1990).
29 *Vela* 426 S.W.2d at 871. *Vela* had been followed by numerous cases in Texas and elsewhere since it was decided. For example, in *Amoco Production Co. v. First Baptist Church of Pyote*, 611 S.W.2d 610 (Tex. 1980), the supreme court stated simply: “The parties can draft either a ‘market value’ or a ‘proceeds’ royalty provision, and their intent will be followed by the courts.” 611 S.W.2d at 610.
The royalty owners had argued that even if the amounts received under the gas purchase contract was not determinative of the amounts payable to them, those amounts should have been “relevant to the determination of market value.” The court rejected this as well, noting that the definition of “market value” was well established, citing Exxon Corporation v. Middleton, in which the Texas Supreme Court stated that to “determine the market value of gas, the gas should be valued as though it is free and available for sale.” While the gas sold pursuant to the gas purchase contract had been available for sale when the contract was entered into, clearly it no longer was when the gas was produced and sold, when Vela and its progeny require the market value of royalty gas be determined. Accordingly, the price under the gas purchase contract was not even relevant to the determination of market value, and evidence of that price was properly excluded by the trial court.

In determining the market value of natural gas at the time of sale, the most favored method would be by “comparable sales,” which means sales comparable in terms of time, quality of the gas, quantity and availability to market outlets, and (in some states) its legal characteristics. When comparable sales are not available, courts are relegated to determining market value on a “net back” basis, in which the market value at the wellhead is determined by taking the proceeds received from a sale off the premises, and deducting therefrom the costs incurred from the wellhead to the point of sale.

The other typical method of calculation of gas royalty is based on the “proceeds” or “amounts realized” from the sale of gas production. Under a “proceeds” royalty clause, the royalties should be payable based on the proceeds received in an actual sale. If the sale is made at the well,

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31 Id.
32 Middleton, 613 S.W.2d, pp. 246-247, 554 F.2d 381 (10th Cir. 1975); Kuntz, § 40.4 at 335.
33 See for example, Piney Woods, Middleton. See also Reed v. Hackworth, 287 S.W.2d 912 (Ky. 1956). A significant component of a net back calculation is the determination of which costs may be deducted and which are to be borne solely by the lessee.
determination of the proceeds on which the royalty would be based presumably should be easy. In the case of the hybrid royalty clauses, whether royalty is based on the proceeds received when the sale is made on the leased premises and on the market value at the well otherwise, the key factor may be whether the sale is deemed to have been made at the well.\textsuperscript{35} This becomes important when a significant variance develops between the proceeds received and the current market value of the production at the time produced.

If the sale of the gas is made off the leased premises, but under the royalty clause the royalties are still to be based on the proceeds received, the calculation should typically still be based on amounts realized at the well.\textsuperscript{36} In this situation, however, the calculation of the amounts realized can be more complicated, as the lessee must determine what portion of the revenues it receives should be deemed attributable to the lease, and what costs can properly be deducted therefrom.

These same problems arise when the market value of gas is to be determined on a “net back” basis from a sale off the leased premises. The traditional division is between the production costs borne solely by the lessee and post production costs which historically have been charged against the revenues of both lessee and lessor.\textsuperscript{37} The traditional view was expressed by Judge John Minor Wisdom in \textit{Piney Woods}, stating that the phrase “at the well” describes “not only the place of sale but also . . . the condition of the gas when sold.”\textsuperscript{38} Thus valuation at the well should

\textsuperscript{35} \textit{See for example, Piney Woods} and \textit{Middleton}.
\textsuperscript{36} \textit{See for example, Warfield Natural Gas Co. v. Allen}, 88 S.W.2d 989 (Ky. 1935). However, for a contrary view, \textit{see Cotiga Development Co. v. United Fuel Gas Co.}, 128 S.E.2d 626 (W. Va. 1962), in which the lease called for royalty payments based upon the royalty percentage of “the rate received by Lessee for such gas.” The defendant United took the gas and transported it to its service area where the gas was sold to its customers. In that case, the court determined that the defendant was required to pay to the plaintiffs its royalty share of the proceeds received by United when first sale of the gas was made to its retail sales customers.
\textsuperscript{38} \textit{Piney Woods}, 726 F.2d 225 at 240.
distinguish between gas sold in the form it emerges from the well and value added by transportation away from the property or processing after production. The Texas Supreme Court decision in Heritage Resources, Inc. v. NationsBank, may present the ultimate application of this principle. In that case, the applicable royalty provision required the lessee:

   to pay the Lessor _ of the market value at the well for all gas (including substances contained in such gas) produced from the leased premises: 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.

Reversing the decision of the court of appeals, the Texas Supreme Court noted that “[m]arket value at the well has a commonly accepted meaning in the oil and gas industry,” meaning “the price a willing seller obtains from a willing buyer.” In light of the meaning of “market value at the well,” the court found that “the only conclusion we can draw is that the ‘post-production clauses merely restate existing law.’” Thus, the commonly accepted meaning of the ‘royalty’ and ‘market value at the well’ “renders the post-production clause in each lease surplusage as a matter of law.” Because there was no evidence of comparable sales, the court found that “Heritage must pay a royalty based on the market value at the point of sale less the reasonable post production costs,” notwithstanding the specific statement in the lease that no post production costs should be deducted.

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41 Heritage, 939 S.W.2d 118 at 122.
42 Id. at 123.
43 Justice Raul Gonzalez, in dissent, focused on the specific language regarding “post-production costs” and asked a logical question: “[w]hat could be more clear? This provision expresses the parties’ intent in plain English, and I am puzzled by the Court’s decision to ignore the unequivocal intent of sophisticated parties who negotiated contractual terms, at arm’s length.” 939 S.W.2d 118 at 131.
In *Carter v. Exxon Corp.*, the Texas Court of Appeals, interpreting a royalty provision also calling for royalties to be paid based upon the market value at the well, rejected the concept that the royalty calculation should be performed by netting back the sales price received from liquid sales. In the court’s view, the phrase “at the well” meant that royalty was to be paid “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 determined “the instant the gas is produced from the reservoir.” Using a net back of the liquids price was not appropriate “because it involves a determination of market value after the gas is produced.”

A more recent line of cases dealing with the allocation of production and post-production expenses employs a “marketable product” theory to shift the burden of at least a portion of the post-production expenses solely to the lessee. This theory has been expressed in two different ways. One is by Professor Kuntz, whose view is simply that the production operations, the costs of which are to be borne solely by lessee, are not completed until lessee has produced a “marketable product.” Professor Kuntz expressed his theory in the following way:

There is a distinction between acts which constitute production and acts which constitute processing or refining of the substances extracted by production. . . . It is submitted that the acts which constitute production have not ceased until a marketable product has been obtained. After a marketable product has been obtained, then further costs in improving or transporting such product should be shared by the lessor and lessee.

Whether this is a fair division of the relevant costs and expenses is an issue for those dealing more directly with the allocation of expenses.

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45 Id. at 397.
46 Id.
48 Id. at § 35.
From the perspective of assessing the royalty obligation in non-traditional sales of natural gas (which is after all, the focus of this chapter), this could yield a workable standard, as whether gas is marketable in the form it emerges from the well, that is, whether it is in a state in which it can be sold, should be readily determinable, and for that reason should not add the risk of uncertainty to the economic burden of the costs for the lessee.

Another version of the “marketable product” theory presents more significant problems. Professor Maurice Merrill, in his treatise *The Law Relating to Covenants Implied in Oil and Gas Leases*, asserted that the lessee’s implied covenant to market requires it to produce a “marketable product,” with no cost of producing such a marketable product chargeable to the lessor. The use of a covenant as a gloss on the interpretation of the royalty clause is a questionable mixture of legal principles. Perhaps more significantly, the use of the covenant to achieve an apparent goal of shifting the cost burden to the lessee distorts the covenant itself. However, Professor Merrill’s premise of an “implied covenant to produce a marketable product” has been adopted by cases in Oklahoma, Kansas, Colorado and North Dakota.

§ 7.04. **Applicability of the Implied Covenant to Market.**

The implied covenant to market production is a logical extension of the lessee’s principal right and duty, to explore and produce hydrocarbons from the leased premises, since absent marketing of hydrocarbons so produced, no proceeds of the production can flow to either lessee or lessor.

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54 West v. Alpar Resources, Inc., 298 N.W.2d 484 (N.D. 1980).
The covenant is generally to be comprised of two components, the duty (i) to make diligent efforts to market production, and (ii) to obtain the best price obtainable by reasonable efforts. In performing its duties, a lessee is not a fiduciary nor is its duty “highest good faith.” The standard, as with other implied covenants under an oil and gas lease, is that of a reasonably prudent operator acting in the interest of both lessee and lessor.

In performing its duties under the implied marketing covenant, a lessee’s performance should be judged on its relationship to each lessor. For example, a lessee who achieved an increase of price under one contract by dedication of other leases was found to have breached its marketing covenant to the second lessor. Similarly, a lessee who failed to take action to secure a pricing benefit under the NGPA for production from one lease because the gas was being sold at a fixed price pursuant to a corporate warranty contract (which was binding on the lessee company but did not actually burden the lease itself) breached the implied covenant. Stated another way, the lessee’s “duty is to do that which would be done by a reasonable, prudent operator holding only the lease in question.” This seems a fair standard. In allocating the benefits of what has been called “cooperative venture” between lessor and lessee, the lessor should fairly benefit from the value his interest in the minerals produces and should not be charged with any burdens or costs not related

60 Id. at 549, citing Amoco Prod. Co. v. Alexander, 622 S.W.2d 863 (Tex. 1981).
to his lands. Logically, however, in applying these principles of the “cooperative venture” to non-traditional marketing arrangements, the lessor should not be entitled to receive the enhanced benefit not relating to the value that the production from his land would yield. Or as Professor Richard Maxwell of Duke Law School stated:

*Piney Woods* puts the basic concept of royalty succinctly and clearly: ‘[t]he royalty compensates the lessor for the value of the gas at the well; that is, the value of the gas after the lessee fulfills its obligation under the lease to produce gas at the surface, but before the lessee adds to the value of the gas by processing or transporting it.*62

*Yzaguirre v. KCS Resources, Inc.*63 provides an indication of how the marketing covenant should (or in that case, should not) be applied to deal with royalty owner complaints. As noted above, in that case, the lessor challenged the lessee’s determination to pay royalties under a “market value” royalty provision based on the current market value rather than on the significantly higher price the lessee was then receiving under a gas purchase contract previously entered into under different market

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62 Richard L. Maxwell, “Oil and Gas Royalties — A Percentage of What,” 34 *Rocky Mtn. Min. Law Inst.*, 15-1, pp. 15-16 (1988). John Lowe expresses a similar view: where royalty is valued at the well by working back from the prices received in downstream sales, costs incurred by the working interest to move or improve the production must be deducted from the downstream sales price, whether the royalty clause calls for royalty based on “market value” or proceeds. The value of any commodity depends upon its proximity to market, and the value of oil or gas normally increases as it moves closer to the burner tip. Thus, post production costs tend to increase the value of the product and must be deducted from the downstream sales price to obtain an accurate valuation “at the well.” It should follow that no royalty is due on revenues generated by a lessee’s downstream or entrepreneurial activities.” John S. Lowe, “Defining the Royalty Obligations,” 49 *SMU L. Rev.* 223 (1996) pages 261-263.

conditions. Applying *Vela*, the supreme court found the lessee’s payment appropriate. The lessors attempted to persuade the court to reach a different result by asserting the lessee had breached its implied covenant to reasonably market the gas by not paying royalties based on the proceeds received. However, the court noted that “there is no implied covenant when the oil and gas lease expressly covers the subject matter of an implied covenant.”

Since the lease provided “an objective basis for calculating royalties that is independent of the price the lessee actually obtains, the lessor does not need the protection of an implied covenant.”

This attempted use of the implied marketing covenant to transform the ‘market value’ royalty into a ‘higher of market or proceeds’ royalty, though perhaps innovative, was not particularly subtly done. The royalty owners stated in oral argument that “the entire body of implied covenant law has been aimed at . . . making sure that the royalty owner gets the best deal.”

While a reading of case law can lead one to the conclusion that some courts have at least implicitly employed this as a governing principle, the Texas Supreme Court rejected it, finding:

The implied covenant to reasonably market oil and gas serves to protect a lessor from the lessee’s self dealing or negligence. It does not override the express terms of the oil and gas lease whenever a lessee negotiates a sales contract that turns out to especially lucrative. We will not now rewrite this lease’s plain terms to give the Royalty Owners the benefit of a bargain they never made.

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64 *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001), *citing* *Danciger Oil & Refining Co. v. Powell*, 154 S.W.2d 632 (Tex. 1941). *See also* *Stirman v. Exxon Corp.*, 280 F.3d 1152 (5th Cir. 2002), in which the court found that no implied covenant to market existed in market value leases, and that therefore a purported class including lessors with both market value and proceeds leases lacked adequate “typicality” to justify the maintenance of the class.

65 *Id.*

66 *Yzaguirre*, 53 S.W.3d at 374.

67 *Id.*
Under current market conditions, many lessees have various marketing options available, with the availability of certain of those options dependent on the ability and willingness of the lessee to perform the tasks not included in the traditional lessee duties which are necessary to access these markets and to incur the resulting costs and expenses to do so. The question of what a reasonable prudent operator would do under the applicable facts and circumstances must be determined under these circumstances. One question to be determined is the extent to which the proceeds derived by the lessee are a part of the value of the gas at the wellhead, or rather constitute value added by the marketing efforts by the lessee which go far beyond what a lessee would traditionally have expected to expend.68

§ 7.05. The Implied Covenant and Current Marketing Options.

In assessing what the marketing covenant means in our current marketing environment, we might review the marketing options for a hypothetical lessee listed above, which included sales of gas at the wellhead, at a pipeline interconnection and at the relevant city gate for a local distribution company. Each of these options would involve different commitments of time, expertise and costs by a lessee, and would involve different risks. While assessing the economic benefit and risks from its own standpoint would be difficult enough for most lessees, a lessee must also consider how its obligations to its lessor should affect its consideration

68 See James C. T. Hardwick and J. Kevin Hayes, “Gas Royalty Issues Arising From Direct Gas Marketing,” 43 Oil & Gas Law & Tax’n 11-48 (1992), in which the authors stated the matter this way:

The lessee’s duty to market developed in the context of market conditions in which the lessee typically limited his delivery obligation to the physical capabilities of his wells and to the specific reserves underlying the dedicated leases. . . . The function of aggregator of supply and warrantor of delivery was performed by the pipeline, not the producer. In contrast, the additional obligations and risks that a producer assumes under today’s premium prices sales contracts should be viewed outside the obligations contemplated by the lessee’s duty to market.
of these options. Stated simply, what does the marketing covenant oblige a lessee to do? For example, is a lessee obligated to access a distant market if in the interest of both lessee and lessor to do so? The traditional view is that a lessee is only required by the duty to market to secure a market at the leased premises. This flows from the fact that the implied covenant evolved during the era in which there typically was only one market, in or near the field, and the lessee’s marketing efforts merely required arranging for the sale of gas there.\(^{69}\) This would also mean that the lessee should not be required to incur significant costs in marketing production. For example, in \textit{Kretni Development Co. v. Consolidated Oil Corp.},\(^{70}\) the court determined that the lessee was not required by the marketing covenant to construct a pipeline.\(^{71}\) A related question: if a lessee elects to access a distant market, are (i) the revenues derived from a distant sale a part of the revenues on which the royalties are computed, and if so, (ii) to what extent are costs required to reach that distant market deductible from those revenues?\(^{72}\)

\(^{69}\) \textit{See Merrill, supra} at 219. “Ordinarily, the production is marketed from the lease, and the lessee’s duty is merely to arrange for sale there.”

\(^{70}\) \textit{Kretni Dev. Co. v. Consolidated Oil Corp.}, 74 F.2d 497 (10th Cir. 1934).

\(^{71}\) In \textit{Union Oil Co. of California v. Ogden}, 278 S.W.2d 246 (Tex. Civ. App. 1955), the lessee was obligated to incur costs to construct facilities beyond the lease lines. However, the pipeline to be constructed would only have been one-half mile.

\(^{72}\) Clearly, the assessment of the lessee’s obligations stated herein assumes that the applicable lease does not contain provisions which address the relevant issue. Leases drafted on behalf of landowners frequently contain royalty provisions precluding deduction of certain expenses, such as gathering, compression, marketing expenses or in certain cases, transportation expenses. Other landowner forms provide specifically that if production is marketed to an affiliate of the lessee, the royalty is based on the proceeds received by the affiliate, not the lessee’s sale to the affiliate. Federal and state leases frequently contain such provisions, either in the lease forms themselves or in regulations interpreting (sometimes retroactively) the obligations of the lessee. A recent innovation by the United States government causing a lessee to account to the government at not less than the amount received by the lessee’s affiliate was sustained by the United States District Court for the District of Columbia in \textit{Fina Oil and Chem. Co. v. Norton}, F. Supp. 2d 246 (D. D.C. 2002), discussed in more detail below. In addition to lease forms and regulations altering the normal rules, for production in Wyoming, the Royalty Payment Act (Wyo. Stat. Ann. Section 30-5-301 \textit{et seq.}) specifies costs which are deemed
While a number of cases have increased the lessee’s economic burden relating to post production expenses, three recent cases present particular problems for lessees assessing non-traditional marketing options. *Mittelstaedt v. Santa Fe Minerals, Inc.* represents the Oklahoma Supreme Court’s most recent decision regarding the “marketable product” rule. The lease involved in that case required royalty payments to be made based on “the gross proceeds received for the gas sold.” The question presented was whether the lessee was entitled to deduct a proportionate share of transportation, compression, dehydration and blending costs from the royalty interest. The court determined that while no costs “associated with creating a marketable product” may be deducted, the lessee could deduct costs of transportation, compression, dehydration and blending if it could establish that:

(i) the costs “enhanced the value of an already marketable product;

(ii) the costs are reasonable; and

(iii) “actual royalty revenues increased in proportion with the costs assessed against the nonworking interest.”

While this decision purported to leave a door open for the deduction of certain post production costs, the problem created for the lessee by this to be included in the cost of production, and as such are borne solely by the lessee. The specified costs include most items which traditionally would have been characterized as post production expenses. For an excellent assessment of how the determination of how the allocation of post production costs should affect the lessee’s determination of its marketing options, see David E. Pierce, “Royalty Calculation in a Restructured Gas Market,” 13 E. Min. L. Inst. ch. 18 (1992).


75 *Id.* at 1209.
standard is that the deductibility of the costs are directly dependent on a benefit to the royalty share. This is particularly problematic in long term non-traditional marketing contracts during the term of which the contract price may at some points provide a premium over market, and at others result in a price less than that available in less risky markets. For example, under a contract providing for gas to be delivered to a distant LDC at a fixed price over the contract term, even if the contract price was significantly above market when entered into — in light of the volatile nature of gas price — it is likely that at some points during the contract term a sale at index prices could exceed the contract price. Seasonal variances being what they are, it would not be surprising if the contract price would exceed a spot market price in eight of the twelve months of the year, but be less than spot market prices at the height of the winter heating season. Should the lessee’s costs in accessing the LDC market be deductible in eight months but not in the other four? This would appear to create a complicated standard which could realistically only be applied retrospectively in a litigation context. In instances in which the lessee has acted as a reasonably prudent operator in marketing production and incurring costs, why should the “marketable product” rule, which arises out of the marketing covenant, result in the lessee solely bearing the full costs during the time period in which its gas contract is out of the money?  

Mittelstaedt does provide a clear lesson for lessees in assessing their marketing options. In distinguishing the prior case of Johnson v. Jernigan, the court stated that decision “allows allocating transportation costs to lessor when the point of sale is away from the lease only when no market for the product is available at the lease. When there is a market

76 In XAE v. SMR Property Management Co., 968 P.2d 1201 (Okla. 1998), the Oklahoma Supreme Court determined that the allocation of costs between a lessee and overriding royalty interest owner were governed by different rules than those pertaining to the lessor/lessee relationship, stating that “unless expressly assumed, implied covenants of a oil and gas lease do not extend to lease assignments with reservation of overriding royalty.” Colorado apparently has adopted a different rule. See Garman v. Conoco, Inc., 886 P.2d 652 (Colo. 1994).

available at the wellhead transportation costs to a point of sale at a distant market should not be allocated against the lessor’s interest” unless in conformance with the standards enunciated above.”

The lesson then for lessees, in Oklahoma at least, is that unless the lessee feels comfortable that it will benefit from the sale of production in a non-traditional market even if it is required to pay (at least from time to time) all costs to access that market, it should not pursue that market.

A second problematic case is *Wellman v. Energy Resources, Inc.*, in which the West Virginia Supreme Court held that unless the lease provides otherwise, in an instance in which the royalties are based on the proceeds received by the lessee, the lessee must bear “all costs incurred in exploring for, producing, marketing and transporting the product to the point of sale.” Although decided in a case in which deliveries were made to a pipeline, the language above is apparently not limited to those facts. Would this mean that when royalties are based on the proceeds or amounts realized, a lessee must bear all costs to any point of sale? It would appear that a West Virginia lessee desiring to access distant markets should at least view that as a possibility.

*Rogers v. Westerman Farm Co.* presents the most severe problems for a lessee wishing to access non-traditional markets. The case involved a large number of leases, all of which called for payment based on gas “at the well,” or some variation of that term. The gas had historically been sold at the well, as the production was stipulated to be sweet gas “ready for commercial and domestic use.” At all times relevant to the decision, the gas from the field was being sold to various purchasers, (i) some quantities at the well, (ii) some to a gathering company who delivered the gas to an interstate pipeline, and (iii) some to other purchasers who accepted delivery at the pipeline. Gathering, compression and dehydration were evidently necessary for the gas to enter the pipeline. In addition,

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78 *Mittelstaedt*, 954 P.2d 1203, 1207.
certain of the lessees incurred transportation costs to get the gas to the point at which they were selling production. Notwithstanding the fact that all the leases provided that royalties were to be computed “at the well,” the court found the leases were “silent” regarding the allocation of costs, even the transportation costs, and determined that the “marketable product” rule would therefore be applied to make that allocation.\(^81\) In the court’s view, the “first marketable product” rule required the lessee to bear all costs until a marketable product was produced.

While the utilization of the first marketable product rule was consistent with the principles set forth in a prior case in Colorado,\(^82\) as well in Kansas\(^83\) and Oklahoma,\(^84\) the Colorado Supreme Court added a significant complication to the lessee’s obligations. In its view, marketability is not merely dependent on the physical qualities of the gas, but also includes “the ability for the gas to be sold in a commercial marketplace,” where there is, as the court said at one point, “an established demand for an identified product.”\(^85\) Although the lessees had argued

\(^81\) Id. at 900.
\(^85\) Rogers at 911. It is interesting to note the Colorado Supreme Court’s heavy reliance on the writing of Oklahoma University Law Professor Owen Anderson. In its initial decision, the court stated in a footnote that Anderson implies that the lessee is bound by the marketing covenant to produce a physically marketable product at a commercial marketplace. However, in a letter dated July 5, 2001, to Justice Martinez, the author of the Colorado Supreme Court decision, Professor Anderson states he “has never implied that a lessee must deliver oil or gas to a ‘marketable location’ free of cost to the royalty owner,” though in his view a lessee is “required to pay royalty on a first-marketable product. (i.e. ‘marketable condition’).” Professor Anderson’s theory of the “first marketable product” “would allow a deduction for transportation away from the immediate vicinity of the well (including transportation-related compression).” His conclusions are “based on historical case law and practices . . . that have consistently allowed a deduction for transportation to a ‘market location’ that is beyond a well’s vicinity and on my belief that words like ‘at
that the fact that the gas had historically been sold at the wellhead, and currently was still being sold there, established that a marketable product existed at that point, the court did not find this determinative. In its view, whether and when a market exists is “an issue of fact to be decided by a jury, based on the facts and circumstances, which may include factors other than a single purchase of gas.” While in the court’s view a commercial market could exist at the interconnection with the interstate pipeline, it left open the possibility that the initial commercial market could be either upstream or downstream from that point.

Although the allocation of costs creates problems similar to those presented by the Mittelstaedt decision, since it leaves a lessee in a position in which it really cannot be comfortable that any costs it may incur to access a non-traditional market can be deducted, the problems for a lessee go further than that. If the lessee is obliged by the implied covenant to produce a “marketable product,” and if marketability requires access to a viable commercial marketplace, presumably the lessee is obligated by the same implied covenant to access that marketplace. This is complicated by the courts’ conclusion that the question of when a commercial marketplace has been reached and a marketable product produced is a question for a jury to resolve. Presumably a jury could conclude that the relevant “commercial marketplace” for gas produced in southwestern Colorado is the L.A. city gate. Or if the Rogers rule were to be adopted in say, West Virginia, the commercial marketplace might be found to be located at the interconnection with the D.C. local distribution company. Under the Rogers rule, a lessee could then be obliged to access that “commercial marketplace” and pay all costs to do so. In any event, with the question left to the jury under the court’s rather vague statement of what a commercial marketplace is, a lessee cannot really be comfortable

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86 Id. at 910.
that it has performed its obligations unless and until a jury tells the lessee it has done so.

Although this chapter is not focused on federal leases, the case of *Independent Petroleum Association of America v. Dewitt*\(^87\) does provide further guidance for lessees in making marketing decisions in the current environment. That case arose from amendments to the regulations governing payment of royalties on federal leases which were promulgated by the Minerals Management Service (MMS) in response to the new world of marketing, in which “direct sales by producers to end users, distributors or merchants became the norm.”\(^88\) The regulations at issue were ostensibly designed to protect the government’s royalties from “improper deductions” by the lessees for downstream marketing costs and expenses.\(^89\) The challenge by the Independent Petroleum Association of America (IPAA) related to the effect of the amendments in denying deductions “for (1) fees incurred in aggregating and marketing gas with respect to downstream sales; (2) ‘intra-hub transfer fees’ charged by pipelines for assuring correct attribution of quantities to particular transactions . . . and (3) any ‘unused’ pipeline demand charge” for firm transportation not actually utilized.\(^90\) The district court held for the IPAA, finding the regulations improper “to the extent that they impose a duty on lessees to market gas downstream . . . and disallow the deductions of downstream marketing costs.”\(^91\)

The D.C. Court of Appeals reversed the district court, basing its decision in part on its determination that deference was due to the MMS, in spite of the fact that it was acting as a “financially self interested”

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88 *Id.* at 1038.
90 *Dewitt* at 1038, the “reasonable actual costs incurred by a lessee to transport . . . gas . . . from a lease to a point” of sale off the leased premises continues to be deductible under the amended regulations. 30 C.F.R. Section 206.156.
party. It noted that marketing costs had historically not been deductible, and found no reason for a “distinction between marketing for leasehold sales and for ‘downstream’ sales.”92 Although acknowledging that “transaction costs may be higher for sales in the current market,” this change in “the dimension of a cost” was not a reason to change the practice for marketing expenses.93 It found the IPAA’s argument in support of such a change “especially weak” in light of the fact that “producers are under no duty to market ‘downstream’ and may opt to sell at the wellhead.”94 The lesson then would be that a lessee should only expend the additional effort, cost and expense in marketing gas from federal leases if it is comfortable that it would be profitable to do so even if (as Dewitt requires) it bears the entire expenses of doing so.

§ 7.06. Dealing with the Options.

Suppose, then, that a lessee had the following contractual options to market its gas:

1) a contract with a local distribution company, with (i) a price $3.75 (above current market), (ii) for a fixed term, (iii) with fixed volumes, (iv) containing a cost of living escalator and (v) with the lessee’s obligations would be backed by corporate warranty from the lessee or its parent;

2) a contract with an independent gas marketer with (i) pricing based on 93% of the price received in resales and (ii) with target volumes, with the percentage of netback adjusted if greater or lesser volumes are delivered; and

92 Dewitt, 279 F.3d 1036, 1040.
93 Id.
94 Id. Note however, that in the case of Fina Oil and Chem. Co. v. Norton, 206 F. Supp. 2d 246 (D.D.C. 2002), discussed in more detail below, the United States District Court for the District of Columbia posed the question “whether Fina’s lease or federal regulations impose a duty on Fina to perform downstream marketing services.” IPAA v. Norton, at 252. Although purporting to rely on the D.C. Court of Appeals’ decision in IPAA v. Dewitt in a number of respects which expressly found that no such duty exists, the district court answered the question in the affirmative, stating that “Interior articulated a rational basis for its decision that they do impose such a duty.” IPAA v. Norton, at 252.
3) a third contract with the owner of a gathering line with (i) prices based on spot market prices less a specified amount, (ii) terminable on 30 days notice and (iii) basically unlimited volumes.

If the lessee at this time had not dedicated any leases to any of these contractual opportunities:

(a) What royalty related factors should affect its marketing decisions?

(b) Suppose there are numerous leases contributing to the production that the lessee could sell pursuant to these contracts, how does the lessee allocate volumes from its leases to these contracts?

(c) What are its risks for challenges from the royalty owners under market value leases or under “proceeds” leases (i) under current pricing, (ii) when prices rise and (iii) when prices fall?

For example, under a “market value” royalty provision, it logically should not matter how the gas is marketed, as the obligations should be established by the value of the gas at the wellhead, subject to the complications under the marketable product theory. Thus, if a lessee chose to sell gas produced under a “market value” lease to a non-traditional market, the lessee would bear the full commodity risk (at least under the Vela principle), as amounts payable to the lessor as royalty should neither be increased when the lessee’s marketing efforts yield a profit nor diminished if its contracts are out of the money. In a jurisdiction in which the Tara rule still applies, if the lessee prudently enters into a gas purchase contract and dedicates a lease to that contract, the price under that contract would establish the market value. The tension would then be whether a lessee’s marketing decision was in fact prudent, and whether the price received was in fact the best price reasonably available.

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95 See Yzaguirre, 53 S.W.3d 368 (Tex. 2001).
96 Vela, 429 S.W.2d 866 (Tex. 1968).
Under an amount realized lease, however, the proceeds in which the lessee would share would vary significantly depending on which one of the contracts the gas from the leased premises was marketed under. Depending on the trends in the gas market, any of these contracts could presumably be the worst at a given point in time, and could be the preferable one at others. Accordingly, depending on the marketing decision the lessee makes, a lessee could face litigation from a lessor receiving less than it would have received had a different decision been made. In judging a lessee’s performance under traditional concepts applicable to implied covenants, if the gas produced from a lease is dedicated to a contract and the contract was one that a reasonably prudent operator would have entered into at the time, the lessee should be deemed to have complied with its implied marketing covenant. A fair principle which might be applied is that “where the interests of the lessor and the lessee are aligned, the greatest possible leeway should be extended to the lessee in his decisions about marketing gas.”  

However, if the lessee has not actually dedicated gas from a lease to a particular contract, the allocation of gas to particular contracts can be a month-to-month or sometimes day-to-day decision. How then should the lessee allocate volumes produced under its various leases to these contracts? It has been suggested that three different methods of allocation might be used:

(i) Dedication/sourcing of leases to contracts in which the lessee treats each lease as if it were dedicated to a particular contract;

(ii) Pooling in which the proceeds derived from leases in a given geographical area are aggregated and allocated back to the leases based on the proportionate volumes; and

(iii) Paying royalties based on a market price which is based on spot market.

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Assuming that gas production under a lease could be delivered under each of the gas marketing arrangements, each of these methods of allocation would appear to present litigation risks, at least under a lease containing an “amounts realized” royalty provision. With respect to sourcing, if there is no legal obligation for the gas to be sold pursuant to any contract unless legally dedicated to that contract, a lessee who receives less as his percentage of proceeds from the sale from time to time than it would have received the gas been allocated to another contract may challenge that allocation. This challenge could well be based on the implied covenant to market with some likelihood of success. For if the lessee’s compliance with the marketing covenant is to be judged as if it held only the lease in question, then any lessee who uses gas from a lease to perform a contract that is below market would be at risk.\textsuperscript{100}

If pooling is employed for leases with amounts realized clauses, a lessor whose gas is physically delivered pursuant to a contract that is more favorable in a given month could claim that it did not receive the actual amounts realized from the sale of gas from his premises. If a lessor asserts such a claim, under circumstances in which its gas was in fact delivered under a higher priced contract, it is questionable whether production from other leases actually sold pursuant to lower priced contracts should in effect dilute the higher royalties that lessor would otherwise have received. There is, however, some support in the case law for the pooling method.\textsuperscript{101}

With respect to the third method, if a lessee makes payment based on the market value of the gas when the relevant royalty clause requires payment based on the amounts realized, it simply has not complied with

\textsuperscript{100} See for example, Shelton v. Exxon, 719 F. Supp. 537 and Louisiana Land & Exploration Co. v. Texaco, Inc. 478 So. 2d 920 (La. App. 1985); but see Amoco Prod. v. Hodel, 627 F. Supp. 1375 (W.D. La. 1986). However, there is some support for the concept of sourcing. For example, under the federal regulations, if the gas can be traced to a particular sale, then subject to compliance with other requirements the royalty should be computed based on that sale. See generally 30 C.F.R. Section 206.152.

\textsuperscript{101} Atlantic Richfield Co. v. Farm Credit Bank of Wichita, 226 F.3d 1138 (10th Cir. 2000).
its royalty obligations. While such a payment method may be fair, concepts of fairness may only bear a tangential relationship to a court’s concept of a lessee’s obligations under an oil and gas lease.

As noted above, royalty payments under market value leases should not be affected by the lessee’s marketing decisions. However, when royalty payments are based on the amounts realized or proceeds derived by the lessee, if multiple marketing options exist and the lease in question is not legally dedicated to a particular contract, there is no risk-free decision, since a lessee will want to share in the proceeds generated when the contract is above market, but will not wish to suffer a diminution in royalties if the contract is out of the money. If then, the problem in non-traditional sales principally relates to “amounts realized” or “proceeds” royalty provisions, then under the common royalty provision in which royalty is payable on the amounts realized on sales at the well, and market value on other sales, the problem should be lessened if gas from a lease were sold at the wellhead, which presumably would make the proceeds equivalent to the “market value.” This could be accomplished through a single wellhead sale to a marketing affiliate of the lessee at the best market value at the well. However, while solving a number of problems, sales to marketing affiliates raise problems of their own.102

§ 7.07. Affiliate Sales.

An affiliate may be defined as an affiliate entity controlling, controlled by or under common control with another entity. If a marketing affiliate of the lessee103 purchases natural gas at the wellhead for the best price

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102 For an excellent discussion of the issues relating to affiliate transactions see Judith M. Matlock, “Payment of Gas Royalties in Affiliate Transactions,” 48 Inst. on Oil & Gas L. & Tax’n 9-1. Unfortunately, some recent cases cited below have increased the risks and hence dismissed the benefits of sales to marketing affiliates.

103 The term marketing affiliate is used here only to mean an affiliate of the lessee which is engaged in marketing activities, as differentiated from the term “marketing affiliate” that is defined in the Code of Federal Regulations to mean “an affiliate of the lessee whose function is to acquire only the lessee’s production and to market that production.” 30 C.F.R. Section 206.51. The significance of that definition, at least initially, was that
reasonably available there, then the price paid by the affiliate should represent the market value of the gas at the wellhead, provide the parameters for the proceeds derived from the sale of oil and gas, and fairly should be the basis for the payment of royalties. If the affiliate then resells the gas at a distant market, the price it receives for its resale is not truly an indication of the market value at the wellhead, and accordingly should not be a relevant indicator of the market value of the gas at the wellhead. In addition to providing, at least theoretically, some degree of surety in the payment of royalties under “proceeds” or “amounts realized” royalty provisions, such affiliate sales would also logically separate the traditional function of the lessee as producer from its function as a marketer of production.104 This division also makes the lessee’s marketing function consistent with the origins of the implied marketing covenant, which arose under circumstances in which the marketing of gas required very little more than tendering gas for delivery to a wellhead purchaser. The multiple functions required to access distant markets would traditionally have formed no part of a lessee’s marketing obligations. Logically, a lessee should not be required to solely bear all the costs to perform those

any lessee selling gas to a marketing affiliate was required to pay royalties based on the price received by the marketing affiliate in its arms length sales of the gas to an unaffiliated third party, while the royalties payable under a sale of gas by a lessee to an affiliate which did not technically constitute a market affiliate was governed by different standards. However, inasmuch as the Minerals Management Service has recently taken the position that in all cases of sales by a lessee to an affiliate, the lessee must pay royalties to the United States based on the price received by the affiliate, a decisions upheld by of the Interior Board and Land Appeals and by a recent decision by a federal district court, the relevance of that definition has been significantly diminished. See Texaco Exploration and Prod., Inc., Docket no. MMS-92-0306-O&G, Fina Oil & Chem. Co., 149 I.B.L.A. 168 (1999), sustained in Fina Oil and Chemical Co., 209 F. Supp. 2d 246 (D.D.C. 2002). These cases are discussed in more detail below.

104 This is consistent with the cooperative venture espoused by Professor Harrell, as it would result in the lessor being compensated for the value of the gas attributable to the gas it produces, rather than the value added by the activities of the lessee. This is also consistent with Judge Wisdom’s Piney Woods decision and Professor Maxwell. See note 60 above and accompanying text.
Some of the functions which a lessee might be obliged to perform to access a distant market might include:

(a) aggregation of volumes to provide adequate supplies of gas to serve most non-traditional markets, including providing warranty of volumes of gas available to supply the contractual requirements;

(b) providing a parent guaranty of the performance obligations of the selling party, with such guaranty backed by the full faith and credit of the seller, rather than being tied to any particular source of supply.\[106\]

(c) construction of any necessary facilities to deliver gas to the purchaser, whether at a pipeline connection or for a distant market;

(d) providing for storage and other services and facilities necessary to meet seasonal swings in end user demand;

(e) paying any reservation charges necessary to secure the degree of transportation services required to be comfortable that the delivery obligations can be performed; and

(f) providing the services necessary to monitor complex transportation issues, including scheduling and balancing, bearing

\[105\] That having been said, since the applicable standard for implied obligations is that of a reasonably prudent operation, the actions to be taken by a reasonably prudent operator in producing oil and gas certainly change as the available technology changes. It could be said that what is required of a reasonably prudent operator under the implied covenant to market should also change as the available marketing options change. For example, under cases such as IPAA v. Dewitt, 279 F.3d 1036 (D.C. Cir. 2002), considering regulations which denied any deduction for “marketing” costs, the court found no difference between actions taken at the wellhead and “downstream” marketing activities.

\[106\] In so doing, the seller must frequently satisfy the credit requirements of the buyer’s treasury group, as well as their marketing department. Unless the seller is investment grade, those credit standards might require that the Seller’s warranty be supported by letters of credit, bonds or other security devices.
risks of the strict balancing penalties – often with shorter cure periods, lower tolerances, and higher penalty amounts as pipelines enforce these penalties.

Each of the functions involves expenditures of capital and management time which would not have been required or even envisioned when the implied marketing covenant was established by the courts and commentators. The value added by these services is in reality a return on the capital and expertise expended in performing them or the balance sheet of the lessee put at risk to support them, and is not rationally the result of the value of gas when produced from a lessor’s lands.

While there are aspects of affiliate sales that make them attractive, affiliate sales also present significant risks. For example, the apparent self-dealing when a lessee sells to a related party represents a divergence of interest between the lessor and lessee. This typically results in stricter scrutiny of the lessee/affiliate contract, as such contracts are frequently viewed as “inherently suspect.” In addition, the somewhat understandable suspicion on the part of lessors that the marketing affiliate has captured value that should be shared with the lessor can create a dangerously litigious atmosphere clouding the lessor/lessee relationship.

The case law arising from affiliate sales is not particularly instructive. Two of the most quoted cases involve the same lessee/affiliate relationship, but two different Texas courts of appeal reached dissimilar results. The first of these two cases, Texas Oil Gas Corp. v. Hagen, involved a hybrid royalty provision, in which royalty was based on the amount realized in sales at the well and market value on other sales elsewhere. Sales were made by TXO to its affiliate Delhi Pipeline at the well. Delhi then transported the gas to a central point in the field where the gas was processed, then transported the gas to two ultimate purchasers, who were end users located 50 and 100 miles away respectively. The court noted

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that the mere fact that an affiliate was wholly owned, with identity of management with the lessee did not justify disregarding corporate entities, which “can only be disregarded if an affiliate is merely a name or conduit through which the parent conducts business.”\(^{109}\) Stated another way, it must appear that the corporation is merely a dummy or sham. Under the circumstances, however, the court of appeal found that Delhi was acting as the alter ego of its parent, and that the trial court was justified in concluding that the “purported sale of gas to Delhi was a sham, and that TXO used that arrangement and its relationship with its wholly owned subsidiary to create an unfair device to deprive plaintiffs of their rightful royalties.”\(^{110}\)

The alter ego finding was based on the following factors: (a) both companies had the same officers, directors, office and field personnel, (b) TXO directly paid all of the payroll and directly controlled all of Delhi’s business functions, (c) property held in the name of Delhi was included in the security for a loan to TXO from a New York bank, and (d) TXO acted as Delhi’s representative for the sales agreements with the two end users. Based on these factors, the court of appeal held that the actual sale took place when the marketing affiliate sold the gas to the end users. Thus the sale by Delhi to the end users was employed as the basis for royalty payment on a net back basis, using the revenues received in those sales less the reasonable costs of transportation and marketing to the point of sale. In addition, the court of appeals awarded exemplary damages on the theory that the lessee was bound by duties of “highest good faith” in its relationship of trust and confidence with the lessor, and had breached that duty, among other ways, by failing to disclose the affiliation with Delhi.

\(^{109}\) Id. at 28; see Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981), for proposition that in order to ignore the separate legal existence of two corporations, it must appear “either (1) that the separate corporate existence is a design or scheme to perpetrate fraud, or (2) that one corporation is so organized and controlled and its affairs so conducted that it is merely an instrumentality or adjunct of another corporation.” 630 P.2d 1269 at 1275.

\(^{110}\) Id., at 28.
On appeal in that same case, the Texas Supreme Court rejected the court of appeals formulation of a fiduciary or “highest good faith” standard. It also determined that the lessor’s claim for breach of the implied covenant to market sounded in contract, and accordingly provided no basis for the award of exemplary damages. However, the Texas Supreme Court found that the lessee had failed to act as a reasonably prudent operator in marketing the production and obtain the terms and conditions that a reasonably prudent operator would have obtained. The holding on this point is sketchy, the sum total being the following sentence:

In light of the fact that the purchaser was a subsidiary, a prudent operator would have secured for itself and the lessors the right to receive sulphur royalties and would have reserved the right to renegotiate the contract price should the market value of the gas escalate.

Because of this holding, the Texas Supreme Court expressed no opinion on the correctness of the court of appeal’s alter ego holding. It remanded the case for the calculation of actual damages.

Two years later, in Parker v. TXO Production Corp., the courts noted that affiliate sales were “inherently suspect,” with the “suspicion” presumably increased by the fact that other producers in the field had received more than the defendant lessee received from Delhi Pipeline, its affiliated gas purchaser. However, other facts relevant to this affiliate sale made these factors not determinative. First, the lessee had a specific need for speedy consummation of a sale to minimize drainage. The affiliated pipeline was active in the area, had an ability to enter into the contract on an expedited basis and take large volumes of gas, each of which helped alleviate the risk of drainage. In addition, the fact that other producers were selling to Delhi on the same terms and conditions indicated that the

112 Id.
terms were those that unaffiliated third parties might have entered into under the same terms and conditions. Under these circumstances, the lessee was not found to have breached its marketing duties.

Plaintiff lessors argued that the court should pierce the lessee’s corporate veil, citing the Hagen decision. However, the court of appeal found that while the facts found in Hagen may have supported that conclusion, it did not find the aggravating factors found present in Hagen to be present in that case, despite the fact that the same corporation structure was involved in both cases.

Another case involving affiliate transactions is Craig v. Champlin Petroleum Co.\textsuperscript{114} In this case, the plaintiff class sought damages arising from the payment of royalties by its lessee Champlin based on a gas sales contract between Champlin and a gas processing joint venture of which it was a 51 percent owner. In support of their claim, the plaintiff introduced evidence that the lessors in a field ten miles away were being paid based on a higher sales price with a different gas processor, which was actually nearer the plaintiff’s lands than the affiliated processor. The district court had found that the contract price paid by the non affiliated processor represented the market value of plaintiff’s gas. On appeal, the Tenth Circuit Court of Appeals noted that Champlin “was to a large extent dealing with itself,” which required the court to “examine carefully the fairness of that contract.”\textsuperscript{115} Nonetheless, it reversed the district court decision, finding in order for a relevant market “to exist, there must be an available buyer for the product.”\textsuperscript{116} Champlin introduced testimony from the manager of the third party processing plant indicating that the plant was operating at capacity and could not have served as a realistic market for plaintiffs’ gas. In addition, the prices paid by that plant were the “highest ever paid in the industry” and were the result of “a peculiar situation which did not establish a normal market for the immediate area.” Other gas sellers in

\textsuperscript{114} Craig v. Champlin Petroleum Co., 435 F.2d 933 (10th Cir. 1971).
\textsuperscript{115} \textit{Id.} at 938-939.
\textsuperscript{116} \textit{Id.} at 936.
the field were being paid by the Champlin joint venture at prices identical to those being used by Champlin for royalty payments. Under those circumstances, the Tenth Circuit determined that “it cannot be said that the . . . contract price was unfair.”

A case in which the affiliate sale was problematic for the lessee was the case of Wegman v. Central Transmission, Inc. Although the facts of the case are relatively complicated, in essence, the defendant was the initial lessee of the leases, and thereafter assigned them to various limited partnerships which it controlled. It entered into gas purchase contracts to buy the gas production from these limited partnerships. Since the payment provisions called for payment based on the market value of the production, the defendant cited Henry v. Ballard & Cordell Corp., in which the Louisiana Supreme Court said that the contract price equaled the market value. Inauspiciously for the defendant, the court initially noted that rule did not apply “when there is an allegation of bad faith or where the contract is unreasonable.”

The finding of facts at the trial level was basically dispositive of the issue for the lessee, as it was found to have (a) failed to act in good faith for the mutual benefit of the lessor and itself as required by the Louisiana Mineral Code, (b) failed to fulfill the contractual obligations owed to plaintiffs, (c) controlled the limited partnerships and used them for its advantage, and (d) did not themselves consider the price paid to the limited partnership to be the first sale of gas under the NGPA. Under that set of facts, it would have been difficult for a court to conclude that the contracts with the lessee’s marketing affiliate in any way established the market value, and the Louisiana Court of Appeals did not do so. The defendant attempted to justify the $1.12 per MCF price differential between what

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117 Id. at 939.
121 Wegman at 448.
the marketing affiliate received and the price used for the payment of royalties as a transportation charge. However, that charge would have been imposed for the use of a line which it cost the defendant just over $30,000 total to build. Perhaps on the basis of hard facts make bad law, or perhaps the “pigs get fat and hogs get slaughtered” principle, the court denied any charge for this line, finding that “by industry custom lessors are not charged for the transportation of gas through small gathering lines.” Market value for the purpose of the royalty clause was found to be the price at which the lessee’s affiliate resold the gas.

While the cases involving affiliate sales are somewhat difficult to reconcile, logically a lessee wishing to employ an affiliate sale should ensure that the affiliate sale is a real sale, fairly representing the value of the gas at the point of sale, and as far from a transparent transaction as it can make it. Among the actions that such a lessee should try to take are the following:

1. observe corporate formalities between lessee and affiliated marketer;
2. separate the functions between the lessee and the gas purchaser so that each of the entities acts through and is controlled by, different officers and directors;
3. ensure that the affiliate purchases are at the best price reasonably obtained by third parties; and
4. establish market value in the field by negotiating gas contracts between marketer and other working interest owners.

If then, the affiliate contract in fact represents the value of the gas at the wellhead, then either under leases providing for the payment of royalties based on market value or proceeds received at the wellhead, it would be logical for the lessee to use the contract price paid by its affiliate as the basis for royalty payments. However, a recent case involving a lease administered by the U.S. Mineral Management Service which,

\[122 \text{Id.}\]
although rooted in the MMS regulations, should be of concern to all lessees with marketing affiliates, not just those holding federal leases. In that case, *Fina Oil & Chemical Co. and Petro Fina Delaware, Inc. v. Norton*,\(^\text{123}\) the United States District Court for the District of Columbia upheld the decision of the Minerals Management Service which required Fina, the lessee, to account to the United States, as lessor, for royalties based on the sums received by its marketing affiliate. While the rationale of the case is somewhat complicated and convoluted, in essence the court upheld the MMS on the theory that any additional value received by the marketing affiliate in its subsequent sale above that paid to the affiliated lessee, regardless of what costs, services and expenses may have been incurred by the affiliate in making such a sale, represented a “marketing fee” which the lessee was not permitted to deduct from the proceeds on which the government’s royalty was to be based.

While the holding in *Fina* is clearly limited to affiliate sales and to leases governed by federal regulations, the implication of the language used by the court could lead to the conclusion that if marketing services are performed by any party, royalty is payable based upon the proceeds received without any deduction for the diminution based upon the marketing fees.\(^\text{124}\) If for example, a lessee were to sell to a marketing company and receive 93 percent of the price received by the marketing company, then an argument could clearly be made by the MMS (and any private lessor choosing to adopt the rationale of the MMS) that the royalty should be payable based upon a 100 percent of the price received by the marketing company, not 93 percent. Under those circumstances, it might well be preferable for a lessee to sell gas at the wellhead based upon market indices, less a transportation adjustment, as it would be more difficult for the lessor to claim that the price differential represented a marketing fee.


\(^{124}\) The court however, specially did not reach “the question of whether Fina would have breached its duty to market had it failed to carry out downstream marketing services and instead had chosen to sell its gas for a lower price at the wellhead. Page 17, note 7.
It is in this sense that royalty burdens may well play a role in the determination of what marketing options a lessee may elect to pursue. In his article in an earlier edition of these proceedings, Professor David Pierce demonstrates that if extensive marketing costs and marketing risks are chargeable solely against the lessee, it can be in the economic interest of the lessee not to incur those costs. If permitted to share such marketing costs to access the non-traditional market, a lessee could well receive higher prices which could inure to the benefit of both lessee and lessor. It is for this reason that the cases which cause all costs and risks of accessing non-traditional markets to the lessee may cause the lessee to pursue marketing alternatives with fewer risks, costs and expenses, but with less attractive returns ultimately for both lessee and lessor.

§ 7.08. Conclusion.

The current marketing environment presents a myriad of marketing options for a lessee. Among the lessons which can be learned from the instability in gas markets over the last several years is the inability to predict what changes will occur in gas prices, except in retrospect. The degree of difficulty inherent in evaluating these options has been significantly increased by the recent cases in several jurisdictions which increase the burdens and risks to the lessee by facilitating the ability of lessors to challenge any decision a lessee may make. The ability of oil and gas producers to adapt to market conditions has been amply proven over the numerous cycles of boom and bust in this business over the last several years. However, the lack of clarity and consistency in the jurisprudence of many of the producing states in this area, as well as the tendency in some of the same jurisdictions to shift all marketing burdens to the producers, has significantly diminished the attractiveness of non-

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126 Royalty provisions contained in oil and gas leases handcrafted by the lessor to include all revenues received by the lessee in marketing gas without any deductions may lead to the same result, with lower actual revenues for the lessor.
traditional markets. The deteriorating condition of many independent marketers resulting from the collapse of Enron has further affected non-traditional markets. While the trend is hardly favorable, there is more that is unclear than is clear in this area. What is clear is that the large sums which can be at issue ensures that such challenges will continue to be made, and that the number of cases which can be cited in an article such as this will likely multiply dramatically by the time the subject matter is revisited. What would be advantageous for the industry, and in most instances for both lessees and lessors, is for the interest of both parties to a lease to be sufficiently aligned to provide the motivation to take the marketing options which could increase the pot of proceeds to be divided among the parties. One would hope that the reasoning of the courts will ultimately follow that principle.