Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically - Part 1

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Part 1

Why All the Fuss? What Does History Reveal?

Part 1 addresses the underlying reason for the current wave of royalty litigation, especially gas royalty disputes, and offers a legal history on the meaning of "royalty." This portion concludes that a major underlying reason for the current wave of royalty litigation lies in the "reform" of the federal oil and gas income tax depletion allowance. This portion also shows that royalty obligations were always set by contract or ordinance and did not arise from property law. Part 2 will address whether oil and gas lessees must pay royalty on gas values attributable to so-called "post-production" activities.

I. INTRODUCTION

This essay will address the following related issues: (1) the underlying reason for the current wave of royalty litigation; (2) a legal history of the meaning of "royalty;" and, (3) whether lessees must pay royalty on any value added to production by "post-production" activities under the provisions of common gas royalty clauses. Stated conversely, this
third issue is whether the lessee may deduct "post-production" costs when calculating royalty. While several writers have discussed this last and related issues,\(^2\) most writers have simply drawn assumptions, generally incorrect, as to the first two. Because a proper understanding of these first two issues is helpful in addressing the third, I will first address these first two issues in some detail. In the remainder of Part 1\(^3\) and in Part 2, I will specifically by lessors. For a recent discussion of these latter topics, see Gary B. Conine, \textit{Crude Oil Royalty Valuation: The Growing Controversy over Posted Prices and Market Value}, 43 ROCKY MTN. MIN. L. INST. 18-1 (1997).


\(^3\) In Part 1, § III, I will focus on the history of royalty provisions from ancient times to the early 20th Century, including early case law and the commentary of traditional legal scholars who have influenced oil and gas case law. In Part 2, the focus will be on more recent royalty case law.
address the third issue—one that has been the subject of much recent litigation.  

My final conclusions, however, may be summarized as follows: In the absence of an express lease provision to the contrary, lessees should be allowed to deduct "post-production" costs when calculating royalty. Stated conversely, in the absence of an express lease provision to the contrary, lessees should not have to pay royalty on any value added to production by reason of incurred "post-production" costs.

This conclusion should come as no surprise because, in general, most commentators and many courts have offered similar views. However, as in the old saw, "The devil is in the details," my detailed answer differs from what some commentators and some courts have stated. Like my mentor Professor Kuntz, I submit that royalty payments should be based on three general principles: (1) royalty should be payable on "production," (2) production is not complete until a "first-marketable product" has been obtained, and (3) express provisions of the royalty clause should govern over the first two general principles, but royalty clauses, being both executory and anticipatory in nature, should be construed as a whole, in light of current market realities, and not narrowly construed by isolating certain words or phrases and ignoring general intent. Although the third principle is trump, the first two principles are important because they provide the foundation for the proper construction of express royalty provisions. Moreover, these first two principles tie the royalty obligation to the point where the exploration and production segment of the oil and gas industry ends based upon factual commercial marketplace realities, rather than on the arbitrary notion that "production" ends at the wellhead, the point where the oil, gas and accompanying brine are severed from the real property, or at some other point downstream of the well.

So why all the fuss over royalty valuation? Although most authorities agree on the deductibility of so-called "post-production" costs, there is substantial disagreement on the definition of "production." This

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4. Although not the prime focus of this essay, in Part 2, I will also comment on the proper meaning of "market value," "market price," "proceeds," or "amount realized" as these words are used in royalty clauses. Contrary to what some courts have held, I believe these terms were intended to be and should be treated as essentially synonymous.

5. In this regard, I will examine how courts have and should construe the words "at the well" and "free of cost... in the pipeline"—phrases commonly found in royalty clauses.

6. 3 EUGENE KUNTZ, LAW OF OIL & GAS § 40.5(b) (1989).  


disagreement even occurs within a single jurisdiction. Consider three jurisdictions, Texas, Oklahoma, and Louisiana.

Texas courts construe “production” within the meaning of the habendum clause as requiring the actual production and use or marketing of oil or gas in paying quantities. This construction is carried forward in the gas royalty clause where royalty is payable on “market price” or on “market value,” in that price or value is determined at the time gas is physically severed from the ground and used or marketed. And when the question is whether royalty is due on take-or-pay revenues, Texas case law implicitly recognizes that royalty is not due on gas until the gas is both actually produced and used or marketed, even though a lessee may have received revenues in the form of “take or pay” payments based on the “deliverability” of a well, i.e., the amount of gas a particular well was “capable” of producing, in contrast to revenues received from actual production and use or sale of gas. Nevertheless, a recent ruling of the Texas Supreme Court regards “production,” for purposes of calculating royalty, as merely the physical severance of gas from the ground at the wellhead, and not the actual use or marketing of production downstream from the wellhead. Hence, royalty may be paid on the “intrinsic value.”


11. Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866 (Tex. 1968).


13. See Transamerican Natural Gas Co. v. Finklestein, 933 S.W.2d 591 (Tex. App.-San Antonio en banc 1996, writ denied) (holding that royalty is not due on take-or-pay settlement revenues); Hurd Enters. v. Bruni, 828 S.W.2d 101 (Tex. App.-San Antonio 1992, writ denied) (holding that royalty is not due on take-or-pay settlement revenues under the implied covenant to market); Mandell v. Hamman Oil & Ref. Co., 822 S.W.2d 153 (Tex.-Houston [1st Dist.] App. 1991, writ denied) (holding that royalty is not due on take-or-pay settlement revenues under royalty clause allowing lessor to take royalty gas in kind but expressly obligating lessee to use best efforts to obtain the most favorable market for production); Kilam Oil Co. v. Bruni, 806 S.W.2d 264 (Tex.-San Antonio App. 1991, writ denied) (holding that royalty is not due on take-or-pay settlement revenues).

14. Heritage Resources, Inc. v. NationsBank, 939 S.W.2d 118 (Tex. 1996) (regarding transportation). Accord, Judice v. Mewbourne Oil Co., 939 S.W.2d 133 (Tex.-San Antonio 1996) (regarding compression costs—companion case to NationsBank that also deals with division orders). As I will explain in Part 2 of this essay, these two decisions, however, may have little, if any, value as precedent.

15. In Phillips Petroleum Co. v. Bynum, 155 F.2d 196, 198 (5th Cir. 1946), cert. denied, 323 U.S. 714 (1946), the court used the term “intrinsic value” to describe the value of gas for which there was no established market price at the wellhead.
of gas at the wellhead based upon a work-back calculation whereby the lessee may deduct a proportionate share of post-wellhead costs from the market value of the gas or from proceeds received from gas sales.\textsuperscript{16}

Disagreement over the definition of production also occurs in Oklahoma. In Oklahoma, and in contrast to Texas, "production" within the meaning of the lease habendum clause is satisfied when a completed well is capable of producing oil or gas in paying quantities. Actual physical extraction and use or sale is not necessary for "production" to have occurred for purposes of the habendum clause.\textsuperscript{17} On the other hand, even though no actual production is required to perpetuate a lease beyond its primary term, "production" for royalty-payment purposes in Oklahoma, consistent with Texas, does require actual production.\textsuperscript{18} Nevertheless, in contrast with Texas, "market price" and "market value" royalties are generally payable on the contract price, not on the current values at the time of actual production.\textsuperscript{19} In further contrast to Texas, production, for royalty purposes, requires the lessee to absorb some of the costs of post-wellhead handling and marketing—costs that are only incurred in the event of actual production.\textsuperscript{20}

Louisiana adheres to a third mix of views. Louisiana courts generally agree with the Texas views that "production" requires actual production and use or marketing,\textsuperscript{21} and that production for royalty purposes occurs at the point where oil and gas are physically severed from the ground, not at the point of actual marketing downstream.\textsuperscript{22} On the other hand, Louisiana courts generally agree with the Oklahoma view that "market price" and "market value" royalties are generally payable on the contract price, not on the current values at the time of actual production.\textsuperscript{23}

\textsuperscript{16} Id.
\textsuperscript{17} See, e.g., Gard v. Kaiser, 582 P.2d 1311 (Okla. 1978).
\textsuperscript{18} See Roye Realty & Developing, Inc. v. Watson, No. 76,848, 1996 WL 515714 (Okla. Sept 10, 1996 reh'g denied) (holding that royalty is not due on "take or pay" payments).
\textsuperscript{19} Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981) (construing a gas royalty clause specifying that royalty was payable "at the market price at the well").
\textsuperscript{21} Smith v. Sun Oil Co., 135 So. 15 (La. 1931).
\textsuperscript{23} Henry v. Ballard & Cordell Corp., 418 So. 2d 1334 (La. 1982) (holding that lessor has the burden of overcoming the presumption that market price equals contract price). See also Hillard v. Stephens, 637 S.W.2d 581 (Ark. 1982). But see Diamond Shamrock Corp. v. Harris, 681 S.W.2d 317 (Ark. 1984) (holding that contract price did not control where gas beneath a large geographic area was dedicated to a gas contract seven years before the lands were actually leased).
However, in Louisiana, in contrast with both Texas and Oklahoma, royalty is generally owed on take or pay payments and settlements. This "kettle of fish" gets larger and more pungent when additional jurisdictions and issues are considered. Accordingly, my ultimate objective is to offer a general and workable royalty payment principle—a principle already supported by case law—to guide trial courts in determining the important question of fact of when "production" occurs for royalty payment purposes. My suggested approach may be used to construe a variety of gas royalty provisions commonly encountered in printed lease forms used by oil and gas lessees in the acquisition of development rights on fee lands in the United States.

I undertake this task in full recognition that setting forth a guiding principle for construing typical royalty provisions may be little more than an academic exercise in states where courts may construe existing case law as binding precedent that mandates the use of a different approach. In nearly all jurisdictions, however, including the major producing states, courts still have the opportunity to clarify and distinguish prior case law without the need for overruling prior holdings. If courts adopt my suggested approach, the result will be: greater uniformity among the various jurisdictions, more consistent interpretation of various (but essentially equivalent) royalty clauses, and a body of royalty case law that is in line with the apparent mutual intent of both producers and royalty owners.

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25. For example, as in Oklahoma (and contrary to Texas), Montana courts seem to have adopted the view that production is satisfied, for purposes of the habendum clause, when a completed gas well is capable of production in paying quantities. Fey v. A.A. Oil Corp., 285 P.2d 578 (Mont. 1955). But, actual production, like Texas (and contrary to Oklahoma), is required in the case of an oil well. Severson v. Barstow, 63 P.2d 1022 (Mont. 1936). And also, as in Texas (and contrary to Oklahoma), Montana courts have held that market-based royalty clauses require that royalty be determined when gas is actually produced at the wellhead and sold, not when the gas sales contract is made. Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978), appeal after remand, 616 P.2d 231 (Mont. 1980).


27. Federal and state oil and gas lease forms are beyond the scope of this article. In addition, detailed royalty clauses found in lease forms drafted on behalf of lessors are largely beyond the scope of this article; however, the basic approach to lessor-drafted clauses should be the same: (1) royalty should be payable on "production;" (2) production is not complete until a "first-marketable product" has been obtained; and (3) express provisions of the royalty clause should govern over the first two general principles. In cases of doubt, however, just as it is appropriate to construe lessee-drafted clauses against the lessee, it is appropriate to construe lessor-drafted clauses against the lessor.

28. Indeed, in many states, the earliest cases are federal decisions that are decided on the basis of what the federal court presumes state law to be.
owners as gleaned from a reasonable construction of the entire royalty clauses commonly encountered in fee lease forms. In essence, I urge courts to view royalty clauses as a forest of very similar trees, not as individual trees in a very diverse forest.

II. THE DEPLETION CATALYST

[N]obody wants to take a lot of profit at their producing subsidiary.²⁹

Jim Shaw, Associate Director
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A. Introduction

Many commentators,³⁰ including myself,³¹ have cited the deregulation of natural gas marketing as the major catalyst for the current wave of royalty litigation. Certainly, deregulation is one reason for some of this litigation, especially the recent litigation over post-wellhead costs because, during regulation, gas buyers often purchased gas at or near the wellhead, thereby absorbing most post-wellhead costs. Deregulation, however, is not the only catalyst. In the 1970s, years before deregulation, there were several major cases dealing with the deductibility of post-wellhead costs.³² Furthermore, the deregulation of gas markets does not explain the current litigation over whether oil royalty payments can be properly paid on the basis of posted field prices.

I submit that a major catalyst, indeed the chief one, lies in the "reform" of the oil and gas depletion allowance. Indeed, as I will demonstrate, if the percentage depletion allowance had not been "reformed," the current oil "posted-price" and gas "post-production" litigation might never have occurred. Depletion reform has encouraged the oil and gas industry to alter its economic structure. Previously, thanks to the general availability of the percentage depletion allowance and a general desire to discourage competition in refining and marketing, the integrated oil and gas industry had both a tax and an economic incentive to push

³⁰. See, e.g., Williams et al., supra note 2; Pierce, supra note 2.
³¹. Anderson, Figures Don't Lie, supra note 2.
³². See, e.g., Atlantic Richfield v. California, 262 Cal. Rptr. 683 (Ct. App. 1989); West v. Alpar, 298 N.W.2d 484 (N.D. 1980). Moreover, during this same time period, there were undoubtedly cases that were settled without a reported decision. I was involved in negotiating one such settlement in 1983, North Dakota v. Gulf Oil Corp., No. A1-81-201 (D.N.D. 1983).
profits upstream toward the wellhead and push costs downstream away from the wellhead. With the reduction in the percentage rate of depletion, the establishment of a percentage depletion production cap for independent producers, and the elimination of percentage depletion for integrated producers, these incentives no longer exist. Indeed, when one considers the typical royalty and production tax burden for a producer, the incentive is reversed today, especially if royalty obligations may be lawfully calculated based upon the intrinsic value of oil and gas at the wellhead. Thus, producers now have an incentive to push profits downstream away from the wellhead and to push costs upstream toward the wellhead. The following discussion demonstrates the role of depletion reform as a catalyst for the current gas (and oil) royalty litigation.

B. A Brief History of the Depletion Allowance

Unlike most other businesses, the oil, gas, and mining industries sell their primary capital: oil, gas, and minerals. Because a given party’s oil, gas, and mineral reserves are estimated, the actual proportionate loss of capital that occurs through production cannot be precisely measured. Nevertheless, Congress has always recognized that some portion of oil, gas, and mineral income must be regarded as a return of capital. Accordingly, the earliest income tax acts recognized that a portion of production income should be attributed to the depletion of reserves. In other words, the depletion allowance recognizes that “mineral deposits are wasting assets...”33 and permits “a recoupment of the owner’s capital investment in the minerals so that when the minerals are exhausted, the owner’s capital is unimpaired.”34 Thus, through the depletion allowance, Congress has recognized that a portion of production revenues constitutes a return of capital that should not be taxed as ordinary income.

In 1913, Congress authorized a depletion deduction not to exceed 5% of the gross value of a mine’s annual output.35 The deduction was limited to the cost of the mine or to its fair market value on March 1, 1913. Congress extended the allowance to oil and gas wells in the Revenue Act of 1916.36 The oil and gas depletion provision allowed taxpayers a deduction from basis determined by a well’s “actual reduction in flow.”37 As applied, taxpayers who purchased proven reserves received a higher cost basis than

37. Id. For properties acquired prior to March 1, 1913, the taxpayer was allowed to recover through depletion the fair market value of the asset on that date.
those who explored for and discovered new reserves. To address this and other deficiencies, Congress enacted the Revenue Act of 1918, which allowed depletion based on the greater of the cost of a new discovery or the fair market value of the discovered reserves. In 1921, this depletion allowance was limited to the net income derived from the depletable property, and in 1924, was further limited to 50% of the net income from the depletable property. This so-called discovery depletion proved difficult to equitably administer because the fair market value of discovered reserves was difficult to estimate fairly and accurately. Accordingly, in the Revenue Act of 1926, Congress enacted a percentage oil and gas depletion allowance of 27.5% of gross income from an oil and gas property, subject to the limit of 50% of taxable income from the depletable property, computed without allowance for depletion. Significantly, the percentage depletion allowance was no longer limited to the taxpayer's cost or basis in the property.

In general, a qualifying taxpayer could claim the depletion based on a recovery of the actual cost of discovery, purchase, and development of a property, i.e., "cost" depletion or, regardless of the taxpayer's basis in the property, based on a percentage of the value of production, i.e., "percentage" depletion, whichever was greater. Percentage depletion typically resulted in a higher deduction for most properties, because the 27.5% depletion allowance was taken from gross income from production over the entire productive life of the property regardless of the taxpayer's actual cost basis in the reserves. In contrast, under cost depletion, the deduction ended when the taxpayer's actual depletable basis was recovered. Although often criticized as a tax "loophole," the percentage

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40. Revenue Act of 1924, Pub. L. No. 68-176, § 204(c), 43 Stat. 253, 260. This limitation is currently 100%.
41. Pub. L. No. 69-20, § 204(c), 44 Stat. 9. The House had initially proposed a 25% depletion allowance. The Senate defeated efforts to raise the depletion rate to 40%, but passed amendments providing for a 30% rate. Ultimately, the two bodies compromised at 27.5%.
42. Thereafter, percentage depletion was extended to many nonrenewable and renewable resources, although the percentage rates varied. For example, while the percentage rate for oil and gas was set at 27.5%, the rate for coal was set at 5%, the rate for metals at 15%, and the rate for sulfur at 23%. Revenue Act of 1932, Pub. L. No. 72-154, § 114(b)(4), 47 Stat. 169, 203.
43. 26 U.S.C. §§ 612, 613(a), 613A(a) – (c) (1997).
44. Under cost depletion, the taxpayer's deduction is a fraction of the estimated recoverable reserves taken from the adjusted basis in the productive property — a basis which declines due to prior deductions.
depletion allowance, together with the intangible drilling cost deduction and the pool of capital doctrine, encouraged investment in oil, gas, and mineral exploration and development.

The percentage depletion allowance for oil and gas remained largely unchanged until the Tax Reform Act of 1969. This Act lowered the oil and gas depletion allowance to 22% and imposed a new minimum tax, which, among other objectives, was designed to levy a minimum tax on so-called "excess" depletion—the amount of percentage depletion claimed in excess of a taxpayer's cost basis in a producing property. Six years later, in the aftermath of increased oil prices resulting from the Arab oil embargo, Congress passed the Tax Reduction Act of 1975—a misleading title from the perspective of the oil and gas industry. This Act eliminated percentage depletion for about 70% of domestic production, i.e., producing properties owned by integrated oil and gas companies, and further reduced the depletion allowance to 15% for the remaining 30% of domestic production. Essentially, only "independents" (producers with little or no refining and retailing interests) and most royalty owners could claim the reduced percentage depletion allowance, and this allowance was limited to a maximum of 2000 barrels per day, decreasing to 1000 barrels per day by 1980. Percentage depletion was further limited to 65% of a taxpayer's overall taxable income, in addition to already being limited to 50% of taxable income from a depletable property. These limitations on depletion could not be avoided through the transfer of proven properties.

The Tax Reform Act of 1976 raised the minimum tax of the 1969 Act. In 1986, Congress eliminated percentage depletion for income derived

45. Subject to several limitations, the intangible drilling cost deduction allows for the immediate deduction (rather than the capitalization) of many costs associated with the drilling of a well, such as construction of road access, preparation of the well site, and expenses incurred in the drilling of a well.

46. The pool of capital doctrine (a doctrine not generally available to taxpayers outside of the oil, gas, and mineral industries) allows two or more taxpayers to contribute money, services, equipment, and property to a drilling venture without treating the transaction as a taxable event.


49. 26 U.S.C. § 613A (1997). Today, a 22% depletion rate is available for gas sold under qualifying fixed-price, long-term contracts; however, such contracts are largely a thing of the past. 26 U.S.C. § 613A(b)(3)(A) (1997) and 26 C.F.R. § 1.613A-7(d) (1997). In King Ranch, Inc. v. United States, 946 F.2d 35 (5th Cir. 1991), the Fifth Circuit Court of Appeals held that a royalty owner may claim this percentage depletion rate whenever gas is being sold under one of these qualifying contracts, even if royalty is payable on the basis of current market values. Qualifying stripper wells qualify for depletion rates between 15% and 25%, depending on the price of oil. 26 U.S.C. § 613A(c)(6) (1997); Revenue Reconciliation Act of 1990, Pub. L. No. 101-508, § 11.523(a).

from sources other than actual production, significantly lengthened the time in which capital investments in oil and gas production may be recovered for tax purposes, and subjected both corporations and individuals to the alternative minimum tax (AMT) regime that it revised in 1978.\textsuperscript{51} The general effect of the AMT regime is that a taxpayer engaged in oil and gas production and subject to the AMT may never fully recover its capital investment. Moreover, one aspect of the AMT regime involves the taxation of "excess" depletion.\textsuperscript{52}

The bottom line for these various "reforms" is that a substantial portion of production income, which historically had been viewed as a return of capital, became taxable income subject to normal income or AMT taxation. Regarding depletion, the current 15% depletion rate, down from 27.5%, is presently applicable to a small percentage of the nation's production, is only available to qualifying "independents," may be claimed for no more than 1000 barrels of oil (6,000 Mcf of gas) per day,\textsuperscript{53} and may not exceed 65% of a qualifying producer's overall taxable income nor 100% of taxable income derived from a particular producing oil and gas property.\textsuperscript{54} The availability and value of percentage depletion is further reduced by the transfer rule and the AMT regime mentioned above. Thus, many oil and gas producers no longer qualify for percentage depletion, and those that do qualify receive less favorable tax treatment. Accordingly, over the past 25 years, the net income tax burden on oil and gas producers has increased, and in some states, the production tax burden may have increased as well.\textsuperscript{55} Moreover, in some parts of the country, the typical royalty rate increased from 1/8 to 1/6, 1/5, or as high as 1/4. These changes have encouraged producers to push income downstream and costs upstream.

C. Depletion "Reform" and Royalty Litigation

Disputes over royalty valuation present the mirror image of disputes over the determination of gross income from the property for percentage depletion purposes.\textsuperscript{56} The major difference is that in the latter, producers favor a high gross income from the property to increase the

\textsuperscript{55} For example, in North Dakota, in 1980, due to an initiated measure, total severance taxes on oil increased from 5% to 11.5%. See 1980 N.D. Laws 649, codified at N.D. CENT. CODE ch. 57-51.1 (dealing with the 6.5% oil extraction tax) and N.D. CENT. CODE ch. 57-51 (dealing with the 5% oil and gas production tax).
\textsuperscript{56} See, e.g., Cannelton Sewer Pipe Co. v. United States, 364 U.S. 76 (1960).
percentage depletion allowance, while in the former, lessees favor a low production valuation to decrease their royalty obligations.

Percentage depletion may be taken on gross income attributable to a producer's economic interest in an oil and gas producing property. Thus, at a 27.5% depletion rate, integrated producers had an incentive to attribute as much of their gross income as possible to their economic interest in the property. A producing taxpayer might try to achieve this objective in three ways: (1) push profits as far upstream as possible by minimizing or eliminating profits from any downstream handling, processing, and refining activities; (2) push the gross-income point, for purposes of calculating the depletion deduction, as far downstream as possible; or (3) both. If either or both succeed, the percentage depletion allowance increases and tax liability decreases. These points are supported in a Federal Trade Commission report that influenced Congress to reform depletion law. Pushing profits upstream and pushing the gross-income point downstream does not affect a producer's ability to deduct intangible drilling costs, deduct day-to-day operating costs, or depreciate all equipment along this post-wellhead stream. The only "price" a producer pays for this effort is a higher royalty burden and perhaps a higher production-tax burden. This

58. In 1973, the Federal Trade Commission reported as follows: Under this system [of percentage depletion], the major integrated firms have an incentive to seek high crude prices. The high crude prices are, however, a cost to major firms' refineries. Thus, an increase in crude prices implies an increase in crude profits but a decrease in refinery profits. The integrated oil companies gain because the depletion allowance reduces the tax on crude profits, while refinery profits are not subject to the same advantageous depletion deduction. A simple model developed by the FTC suggests that for American integrated firms that typically produce between 40 and 80 percent of their crude needs, it pays to raise crude prices to a point where refinery profits have been reduced to zero. . . .
   . . . [T]he tax laws have made it highly remunerative for integrated firms to artificially shift profits away from downstream activities toward the crude end of integrated business. . . .

PERMANENT SELECT COMMITTEE ON SMALL BUSINESS, PRELIMINARY FEDERAL TRADE COMM'N STAFF REPORT ON ITS INVESTIGATION OF THE PETROLEUM INDUSTRY, H.R. Doc. No. 96-433, at 21 (1973). This report further concludes: "The depletion allowance worked to encourage vertically integrated firms to report all profits at the crude oil stage rather than at later stages such as refining and marketing." Id. at 29. "[T]he existence of the depletion allowance for crude production means the profits based on high prices at the crude level are 'worth' more to the integrated firm than profits at other levels." Id. at 32. The report called such prices "artificially high." Id. at 44.
59. This statement assumes that producers accounted for royalty and production tax purposes the same as for income tax purposes. See, e.g., Exxon Corp. v. United States, 33 Fed. Cl. 250, 263 – 64 (1995) (wherein Exxon made the same accounting for both royalty and
"price" was acceptable when the depletion rate was 27.5\% (and was probably acceptable when the depletion rate was 22\%) given that the typical royalty rate was 12.5\% and that the typical production tax rate was commonly 5\% or less.

In contrast, there is no incentive to push profits upstream or the depletion point downstream under cost depletion—the only depletion available to major integrated companies and many independent producers. In fact, because of royalty and production tax burdens, a producer who claims cost depletion would ordinarily benefit by pushing profits downstream or by determining gross income from the property as far upstream as possible or both. Likewise, there is little or no incentive to push profits upstream or the depletion point downstream under 15\% percentage depletion, especially when current royalty burdens alone may commonly exceed 15\%.

To illustrate how a change in the depletion rate can affect royalty accounting, compare the following examples:

Example 1. Assume, by either pushing profits upstream or the gross-income point downstream or both, that a producer who is not making an arm's length wellhead sale of gas claims that the gross income from the property for depletion, royalty, and production tax purposes is $2.00/Mcf. Assuming a 12.5\% royalty and a 2.5\% overriding royalty, the producer's total royalty obligation is 30\c. Assuming a 5\% production tax, the total production tax liability is 10\c; however, because production taxes are generally prorated among all working interest and royalty interest owners, the producer's net production tax liability is 8.5\c. Thus, the producer's net royalty and production tax liability is 38.5\c. At a 27.5\% depletion rate, the depletion allowance for the producer's share of the gas is 46.75\c (100\% of production @ $2.00/Mcf minus a 15\% total royalty burden times the 27.5\% depletion allowance). The net benefit to the producer is 8.25\c, the difference between the 46.75\c depletion allowance and the 38.5\c royalty/production-tax burden.

Example 2. Now assume that a producer claims that the gross income from the property for depletion, royalty, and production tax purposes is only $1.00/Mcf. The total royalty

60. The royalty owner and overriding royalty owner can take depletion on their share of the gas. The law requires that the depletion allowance be "apportioned equitably between the lessor and lessee." 26 U.S.C. § 611(a), (b)(1) (1997).

61. The Tax Court recognized this net benefit to lessees in Shamrock Oil & Gas Corp. v. Commissioner, 35 T.C. 979, 1035 (1961), aff'd, 346 F.2d 377 (5th Cir. 1965).
burden would be 15¢, and the producer's share of production tax liability would be 4.25¢, resulting in a total royalty and production tax liability of 19.25¢. The producer's share of the 27.5% percentage depletion allowance is 23.375¢. The net benefit to the producer is 4.125¢, half of the 8.25¢ net benefit realized if the gas had been valued at $2.00/Mcf.

A comparison of these two examples illustrates how the 27.5% depletion allowance provided an incentive for producers to claim a high gross income from their economic interest in the producing property—one might say an "artificially high" gross income.

Today, because integrated oil and gas companies and many independents cannot take percentage depletion, they have little, if any, incentive to push profits upstream or to push the gross-income point downstream. Those producers who are allowed to take percentage depletion at a reduced 15% rate may nevertheless be disinclined to either push profits upstream or the gross-income point downstream because it may often cost them more in royalty and production taxes than is gained from percentage depletion:

In Example 1, above, where the gas is valued at $2.00/Mcf, the producer's share of percentage depletion at a 15% rate would be reduced to 25.5¢, but the producer's total royalty and production tax burden would still be 38.5¢. This valuation would "cost" the producer 13¢.

Under Example 2, above, where the gas is valued at $1.00/Mcf, the producer's share of a 15% depletion allowance would be worth 12.75¢, the producer's total royalty burden would be 15¢, and the production tax burden would be 4.25¢. This valuation would "cost" the producer only 6.5¢. Thus, by either pushing profits downstream or pushing the gross-income point upstream or both, the producer saves 6.5¢/Mcf by valuing the gas at $1.00/Mcf.

Presently, a royalty owner (and production tax collectors) might argue that producers of both gas and oil have an incentive to claim an "artificially low" gross income from the property in order to lower their royalty payments and production taxes. Of course, a lessee might respond that, under the old 27.5% depletion rate, producers had an incentive to calculate the gross income from the property at an "artificially high" level.

An appropriate means of mitigating this current incentive to minimize gross income from the property would be to construe the typical royalty clause as obligating the lessee to "produce" a first-marketable product cost-free to the lessor. Under a first-marketable product approach, royalty valuation would be objectively based upon real market data, rather than, as often occurs, on the lessee's self-serving calculations of post-
wellhead costs. A first-marketable product approach would require that royalty valuation be based on any actual proceeds derived from gas sold in a first-marketable condition or based on objective data obtained from a study of actual sales of comparable gas in a first-marketable condition in a real and existing market. Other than calculating any incurred and deductible transportation expenses, a work-back calculation of post-wellhead costs would be unnecessary and irrelevant.

D. Policing the Percentage Depletion Allowance

1. Oil & Gas

Although, when the percentage depletion allowance was 27.5%, producers had an incentive to push profits upstream or push the gross-income point downstream or both, they were restricted in this endeavor by the tax code and underlying tax regulations. A major objective of these restrictions was to prevent integrated producers from gaining a tax advantage over independents, and enforcement emphasis was on preventing the taxpayer from pushing the gross-income point downstream. These restrictions may be summarized as follows: Depletion may be claimed only by producers and must be calculated against the taxpayer’s gross income from the property—income fairly attributable to gas production—based upon a representative market or field price in the immediate vicinity of the well, and not on its value at a downstream point of sale. Accordingly, in calculating gross income from a property, any

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62. The basis and formula for making these calculations vary from lessee to lessee and are given varying treatment by the courts. See generally Anderson, Figures Don’t Lie, supra note 2.

63. PRELIMINARY REPORT—DEPLETION—OIL AND GAS REVENUE ACT OF 1926, 69th Cong., 12-13, at 23 (1927) (finding that major oil companies could stifle competition from independents in the downstream processing, transportation, and refining sectors of the oil and gas industry by cutting their profit margins on these sectors and pushing their overall profits upstream).

64. For example, if the lessee makes a wellhead vicinity sale, gross income from the property ordinarily means the price the taxpayer receives for the production even if the sale is to a downstream affiliate at a price that is below the posted field price. See Rev. Rul. 90-62, 1990-2 C.B. 158. Case law, however, has allowed a taxpayer, in such an instance, to claim depletion on the higher posted price. See, e.g., Exxon, 88 F.3d at 977–78.

65. 26 C.F.R. § 1.613-3 (1997). Royalty owners are treated somewhat differently. If a royalty owner is entitled to royalty on downstream values (not wellhead values) or on current market values (not a lower long-term contract price paid to lessee), the royalty owner is entitled to include all royalty as gross income subject to depletion on the theory that all royalty is simply a payment made for the right to develop the lessor’s property. In such a case, the lessee’s gross income subject to depletion is limited to the difference between the representative market or field price and the royalty paid. In other words, a royalty owner
may get a larger share of the total depletion allowance than the royalty percentage suggests. See generally Charles P. McKeon, Tax Phases of Cycling Operations, 4 INST. ON OIL & GAS L. & TAX'N 281, 298 (1953). See, e.g., Mesa Petroleum Co. v. Commissioner, 58 T.C. 374 (1972).

To illustrate, if a royalty owner is entitled to 12.5% of the downstream value of gas sold for $2.00, the royalty owner would receive 25¢ royalty and could take depletion on the full amount. At a 27.5% depletion rate, the royalty owner could deduct about 7¢ as depletion. However, the lessee would have to calculate the total depletiable value of the gas at its representative market or field price. If this value were $1.00, the lessee must subtract the full 25¢ royalty and claim depletion on the remaining 75¢—about 21¢. In contrast, if a lessee were limited to depletion on the $1.00 representative market or field price, the lessee could claim a depletion deduction of about 3.5¢ and the lessee could claim about 24¢. Thus, from a percentage depletion standpoint, the lessee can “lose” a portion of its fractional share of the depletion allowance if royalty is owed on the gross value of gas after “manufacturing.” Accordingly, to maximize percentage depletion benefits for itself, a lessee would not want the royalty obligation to go downstream of the point at which gross income for purposes of depletion is determined.

As an aside, “take or pay” payments are also not gross income from the property subject to depletion, 26 U.S.C. §§ 613A(d)(5) and 613(e)(4) (1997), even though, in a few states, royalties are due on “take or pay” payments. And although a portion of settlements for breach of take or pay contracts may be subject to royalty, such payments cannot be included in gross income from the property for purposes of depletion. Cf. Frey v. Amoco Prod. Co., 603 So. 2d 166 (La. 1992) with Rev. Rul. 77-57, 1977-1 C.B. 166. But see Amherst Coal Co. v. United States, 71-1 T.C. 9223, 27 A.F.T.R.2d 71-460 (4th Cir. 1971).

Regarding stored gas, a lessee must ordinarily pay royalty on the basis of the initial production of gas, even if the gas is reinjected for storage rather than immediately sold. But the lessee must recognize gross income for purposes of depletion in the year of sale, not in the year of production. Rev. Rul. 76-533, 1976-2 C.B. 189; cf., Sondrol v. Placid Oil Co., 23 F.3d 1341 (8th Cir. 1994). In Sondrol, lessors sued the lessee for failing to pay royalties on the value of gas placed in storage. The lessee sold gas at the wellhead to a third-party processor. Under the arrangement, the processor was expected to resell the resulting dry gas and pay the lessee 75% of the sale proceeds, and the lessee, in turn, anticipated paying royalties to the lessor on the proceeds received from the processor. Initially, the processor sold the processed dry gas to a utility; however, in 1983, the utility curtailed its purchases, but did announce that it would continue to take excess gas and place it in storage. Later when the utility refused to pay for the stored gas, the processor transferred the stored gas back to the lessee who resold it at a much lower price. The lessee then paid royalties on the lower resale price. The royalty clause of the lease provided that the lessee would pay lessors “1/6 of the proceeds received for gas sold from each well... or the market value at the well of such gas used off the premises...” The lessors argued that the lessee should have continued to pay royalty on the stored gas based upon the gross proceeds payable by the utility prior to curtailment. The court found that the “proceeds” portion of the gas royalty clause governed because the wet gas was sold to the original processor at the wellhead, although the proceeds of the initial sale were not actually “received.” The court found that the market value clause did not apply because the gas had been stored by a third party, not “used off the premises.” The court then rejected the lessors’ claims that lessee had improperly deducted gross production taxes calculated on the higher initial sales price and had improperly paid royalty based upon the proceeds actually received, less processing costs.

While the above examples illustrate that accounting for depletion purposes and accounting for royalty purposes may not be identical, it is usually very similar. See, e.g., Exxon, 33 Fed. Cl. 250. For example, most leases contain a provision that no royalty is
value attributable to post-production processing and transportation is excluded. Thus, if a producer does not sell production in the immediate vicinity of the well, but postpones sale until it has been “manufactured or converted into a refined product” or both, “the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation.” For example, where a producer extracts liquids from wet gas prior to sale, this activity is considered a “manufacturing” process, not a production process, and the taxpayer may claim depletion only against the “representative market or field price” of the casinghead gas prior to extraction of gasoline.

A “representative market or field price” is generally calculated by determining the weighted average of prices received by producers for sales payable on production used by the lessee to further develop and operate the property. Likewise, the value of production so used cannot be included in the calculation of gross income from the property. See, e.g., United States v. Henderson Clay Prod., 324 F.2d 7 (5th Cir. 1963), cert. denied, 377 U.S. 917 (1964); Roundup Coal Mining Co. v. Commissioner, 20 T.C. 388 (1953). But see Woodward Iron Co. v. Patterson, 173 F. Supp. 251 (N.D. Ala. 1959).

However, a taxpayer was allowed to claim percentage depletion on wet gas consumed in the operation of the taxpayer’s downstream gasoline absorption plant. Rev. Rul. 68-665, 1968-2 C.B. 280.

See, e.g., Exxon, 33 Fed. Cl. 250 (holding a representative market or field price may not include value added by transportation and dehydration); see also Consumers Natural Gas Co. v. Commissioner, 78 F.2d 161 (2d Cir. 1935) (concerning gas that was sold to various consumers after piping the gas a distance of one to five miles from the well); Evans v. Commissioner, 11 T.C. 726 (1948) (concerning oil transportation).

Because depletion is available to those taxpayers who have an “economic interest” in a producing property (thereby excluding non-producers), a downstream taxpayer who enters into an arm’s length contract with a producer to process gas and extract natural gasoline for a share of either the revenues, dry gas, or gasoline is not entitled to depletion because that taxpayer has no economic interest in the producing property. Revenue Act 1926, Pub L. Ch. 69-20, §§ 204(c)(2), 234(a)(8), 44 Stat. 14, 41; Revenue Act 1928, Pub. L. Ch. 70-562, §§ 23(l) – (m), 114(b)(3); 26 U.S.C. § 23 (1997); 26 C.F.R. § 1.611-1(b)(1) (1997). See also Rev. Rul. 68-330, 1968-1 C.B. 291 (stating that to qualify for depletion, the taxpayer must have a capital investment in the oil and gas in place; hence, a taxpayer who takes wet gas after it has been produced at the wellhead by another, extracts the liquids, and gives a share of net proceeds to the producer is not entitled to claim percentage depletion); Greensboro Gas Co. v. Commissioner, 79 F.2d 701 (3rd Cir. 1935) (holding that, for depletion purposes, a gas company who both produces and distributes gas to end users via a pipeline must value gas at the well before it is put into the pipeline); Rev. Rul. 75-6, 1975-1 C.B. 178. See, e.g., Helvering v. Bankline Oil Co., 303 U.S. 362 (1938).


66. See, e.g., Brea Canyon Oil Co. v. Commissioner, 77 F.2d 67 (9th Cir. 1935). In this case, the IRS allowed 40% of the gross receipts from the sale of the extracted gasoline to be subject to depletion with the remaining 60% being attributable to manufacturing and not subject to depletion. Id. at 68.
of similar quantities and qualities of gas in the vicinity of the well. Under this preferred approach, depletion values are based on actual sales. While this method is similar to the "comparable sales" method used in royalty valuation to calculate the market value of gas at the wellhead, these methods are not necessarily identical. For example, in a royalty valuation dispute in Texas, "market value" at the well may be calculated by looking at comparable sales of gas sold under contemporary contracts for gas that is similar in quantity and quality, including similar legal quality. (Prior to federal deregulation of natural gas prices, interstate gas was not comparable to intrastate gas.) For depletion purposes, however, a representative market or field price may be determined by considering both vintage and contemporary gas contracts involving both interstate and intrastate gas.

If there are no comparable wellhead sales, then a net-back (Fiske) method has been used to determine a representative market or field price. Under the Fiske method, comparable downstream sales are reduced by the costs of transportation and manufacturing, plus a return on these investments, to arrive at a representative market or field price. In other words, in theory, the price is determined by subtracting from the downstream sales price what a third-party would charge the producer for manufacturing and transportation. If a particular "manufacturing" facility also performs a "production" function (such as recycling for pressure maintenance), then total plant costs may be allocated between the production function, which is subject to depletion, and the manufacturing function, which is not subject to depletion.

69. See, e.g., Exxon, 88 F.3d 968. In the case of oil, the posted prices for oil in the field usually establish the representative market or field price.

70. See, e.g., Exxon Corp. v. Middleton, 613 S.W.2d 240, 245—46 (Tex. 1981) (comparing 30,000 gas sales contracts covering a substantial portion of the Texas Gulf Coast and concluding that market value equaled the quarterly average of the three highest prices).

71. Id. at 246. See also Shell Oil Co. v. Williams, Inc., 428 So. 2d 798, 802 (La. 1983).


73. See, e.g., Scofield v. La Gloria Oil & Gas Co., 268 F.2d 699 (5th Cir. 1959). The "Fiske" method is named for Leland Fiske, former Chief Oil and Gas Engineer for the Dallas Office of the Internal Revenue Service. See generally E. Roy Gilpin, Special Depletion Problems Relating to Gas Production, 12 INST. ON OIL & GAS L. & TAX’N 347, 382 n.43 (1961).

74. Historically, the basic formula subtracts from the downstream sales price the sum of the annual cost of operating the downstream facilities, the annual tax depreciation allowable for such facilities, and an annual return on investment (commonly 20% on the gross investment). See generally McKeon, supra note 65, at 290—91. Because the net sum of this calculation fluctuates with changes in sales prices and with the actual productivity of the plant, averages are established and accepted by the IRS after several years of plant operation. Id.

75. Id.
As with royalty-valuation, when calculating depletion, the point where "production" ends and "manufacturing" and "transportation" begins is not crystal clear. Although court opinions and revenue rulings provide some guidance to supplement the Code and regulations, the degree of taxpayer compliance with these rulings is uncertain. While the initial gravity "separation" of the production stream into oil, wet gas, and water streams is regarded as production, the extraction of liquids from wet gas by absorption and fractionation is regarded as manufacturing. The treatment of gas to remove impurities such as hydrogen sulfide, and the compression of gas for transportation are generally considered manufacturing and transportation functions, respectively. Although compression to reinject gas into a producing formation for pressure maintenance should logically

76. The Fiske method is similar to the work-back method used to calculate gas royalty payments in the common situation where there are no "comparable sales" of gas "at the well." See, e.g., Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970). However, regarding royalty calculations, there is little, if any, credible authority for allowing a lessee to deduct a return on investment, or anything greater than the actual depreciation of the post-production facility over the useful life of the plant, less salvage value. See generally Anderson, Figures Don't Lie, supra note 2.

77. In Exxon Corp. v. United States, 88 F.3d 968 (Fed. Cir. 1996) (holding that value added by transportation and dehydration was not subject to depletion), the Court of Appeals for the Federal Circuit commented as follows on the task of determining a reasonable market or field price (RMFP):

[C]alculation of the RMFP is a difficult and sometimes onerous task. This difficulty is exacerbated by the fact that the Secretary has declined to promulgate regulations which could provide guidance to taxpayers and the courts. In the absence of such guidance, both the taxpayers and the courts must formulate and evaluate the RMFP based on a common law approach that looks to prior adjudications of depletion allowances.

Id. at 976.

78. One critic has argued that the point for determining the gross income from the property should be when the first marketable product has been obtained and should include compression up to the point at which the gas enters the pipeline or a gasoline plant as well as any "processes which the ordinary run-of-the-mill gas operator must perform to establish a marketable product." Richard E. Flint, Gas Compression: Manufacturing, Production, or Marketing, 23 OIL & GAS TAX Q. 233 (1975).

79. See, e.g., Mountain Fuel Supply Co. v. United States., 449 F.2d 816, 822 (10th Cir. 1971); Shamrock Oil & Gas Corp. v. Commissioner, 346 F.2d 377 (5th Cir. 1965).

Two cases, however, treat absorption as a production process where the resulting dry gas stream is reinjected into the producing formation for pressure maintenance: Weinert Estate v. Commissioner, 294 F.2d 750 (5th Cir. 1961) and Scofield, 268 F.2d 699. However, the value of the dry gas that is reinjected cannot be included in the gross income from the property. Rev. Rul. 68-665, 1968-2 C.B. 280.

80. Rev. Rul. 75-6, 1975-1 C.B. 178; cf., Louisiana Land & Exploration Co. v. Commissioner, 102 T.C. No. 2 (1994) (extraction of sulfur from hydrogen sulfide previously separated from gas was a "mining" process entitling the taxpayer to take percentage depletion on the extracted sulfur).
be a cost of production,\textsuperscript{81} intervening manufacturing functions may prevent such treatment.\textsuperscript{82} Dehydration is also regarded as a manufacturing function on the premise that it "requires a chemical reaction,"\textsuperscript{83} even though the oil and gas industry regards it as an "ordinary production activity . . . [usually performed] by the producer. . . ."\textsuperscript{84}

In 1969, the Internal Revenue Service proposed regulations that would have listed specific types of processes as production processes and others as manufacturing processes.\textsuperscript{85} Under these proposals, mechanical separation; gathering within the immediate vicinity of the well; treating to remove hydrogen sulfide or to control the formation of hydrates; the removal of water by absorption, adsorption, or refrigeration; production measurement and testing; stock tank storage; and injection of gas or water for pressure maintenance were to be classified as production activities subject to depletion.\textsuperscript{86} Conversion or transportation processes such as the extraction of liquids, helium, or sulfur for sale or use and the compression of gas into a pipeline were not subject to depletion, including, as a general rule, any production processes that followed any conversion or transportation processes.\textsuperscript{87} Unfortunately, these proposals, which better reflected what industry viewed as production and post-production activities, were withdrawn in 1971.\textsuperscript{88}

2. Other Minerals

In the case of minerals other than oil and gas, percentage depletion was traditionally taken at the point where the extracted ore first became a marketable product, i.e., after application of ordinary treatment processes applied by miners to make the product marketable.\textsuperscript{89} To prevent an integrated miner from pushing the point for determining the gross income

\begin{thebibliography}{99}
\bibitem{81} Weinert, 294 F.2d 750; Scofield, 268 F.2d 699.
\bibitem{82} Cycling plants commonly perform initial separation and injection functions—generally regarded as part of production, but they also perform absorption and fractionation functions—generally regarded as manufacturing. The problem of calculating wellhead depletion values where the production is run through a field cycling plant has been explored in detail. \textit{Cf.} Paul Munter \& Don W. Finn, \textit{Industry Joint-Product Allocations, 1984 – 1985}, \textit{Oil \& Gas Acct. 10-1} (1985) (pointing out that, in evaluating individual sectors of a multi-function facility, an accountant's allocation of costs among the various products in a joint-product facility is generally arbitrary). \textit{See generally}, McKeon, \textit{supra} note 65, at 290—91.
\bibitem{83} Exxon Corp. \textit{v.} United States, 88 F.3d 968, 978 (Fed. Cir. 1996).
\bibitem{84} Id.
\bibitem{86} Proposed Regulation § 1.613(a)(2) (1997).
\bibitem{87} Proposed Regulation § 1.613(a)(3)(i)m (1997).
\bibitem{89} \textit{See, e.g.}, Cannelton Sewer Pipe Co. \textit{v.} United States, 364 U.S. 76 (1960).
\end{thebibliography}
from the property downstream, depletion could not be claimed against the
gross income derived from a finished product after manufacturing. Rather,
the integrated mining company had to treat this situation as if the taxpayer
had sold the first-marketable product to itself for further fabrication.90

In general, the point at which mining ends and manufacturing
begins is the point where gross income is to be calculated for depletion
purposes. The landmark case dealing with the issue of when mining ends
and manufacturing begins is Cannelton Sewer Pipe Co. v. United States.91 Prior
to Cannelton, some taxpayers successfully argued that gross income from
the property included income derived from a finished product.92 In
Cannelton, however, the Supreme Court held that income derived from
manufacturing and fabricating could not be classified as mining processes
even if such activities were necessary for the particular business to generate
a profit.

After Cannelton, the IRS required taxpayers to calculate a
"constructive" gross income from the property at the point at which the
mining process ended even though the particular ore may not have been
actually marketable at that point.93 Courts, however, did not always agree
with the IRS and were willing to consider whether a market existed for a
particular mineral in the absence of further processing. For example, in Dow
Chemical v. Commissioner,94 the court held that, because there was no market
for natural brine, the extraction of constituent minerals should be regarded
as a mining process. In Barton Mines Corp. v. C.I.R.,95 the court held that the
further processing of ore consisting of 91% garnet concentrate was mining
because there was no market for garnet of that grade.

To prevent integrated miners from pushing profits upstream into
the price of the marketable ore, tax regulations for minerals other than oil
and gas provide that "first-marketable product" means a product "in form
or condition in which such product or products are first marketed in
significant quantities by the taxpayer or by others in the taxpayer's
marketing area."96 If the product is marketable at the point where mining
ends, then gross income from the property is the representative market or

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90. Id. at 89.
91. Id. at 76.
92. See, e.g., United States v. Cherokee Brick & Tile Co., 218 F.2d 424 (5th Cir. 1955)
(bricks); Riverton Lime & Stone, Inc. v. Commissioner, 28 T.C. 446 (1957).
94. 433 F.2d 287 (6th Cir. 1970).
95. 446 F.2d 981 (2d Cir. 1971).
field price for that ore, or for similar ore at that point, provided that this price plus the sum of all manufacturing costs does not regularly exceed the price actually received for the product downstream.

In contrast to oil and gas depletion law, current depletion law regarding other minerals specifies those processes that may be included and those that must be excluded in determining gross income from a mine. Transportation, even by common carrier, of ores up to a distance of 50 miles is a "cost of mining" if the destination is a facility that constitutes a "mining" facility, if the costs of processing are borne by the miner, and if the miner retains title to the ore. In other words, income or value attributable to the initial transportation of ore to a mining facility need not be excluded in determining gross income from the property. Today, the listed mining processes, or any substantially equivalent processes, may be considered part of the mining process even where the taxpayer actually markets some ore prior to such processes; however, the actual sales price of any ores so sold constitutes the gross income from mining for those ores even if they are thereafter subjected to mining processes.

If a listed mining

97. Id. § 1.613-4(c)(1) (1997). The calculated price is presumed not to be a "representative market or field price . . . if the sum of such price plus the total of all costs of the nonmining processes (including nonmining transportation) which the taxpayer applies to his ore or mineral regularly exceeds the taxpayer's actual sales price of his product." Id. § 1.613-4(c)(6). This limitation is not found in the oil and gas depletion regulations. Cf. Exxon Corp. v. United States, 88 F.3d 968, 972–74 (Fed. Cir. 1996) (reviewing prior case law and concluding that the representative field or market price could exceed a producer's gross income "because of the effects of changing market conditions").

98. 26 C.F.R. § 1.613-4(c) (1997).


100. 26 U.S.C. § 613(c)(2) (1997); see also Rev. Rul. 84-26, 1984-1 C.B. 142; Rev. Rul. 77-457, 1977-2 C.B. 207; Rev. Rul. 73-474, 1973-2 C.B. 201; Ideal Basic Indus., Inc. v. Commissioner, 82 T.C. 352 (1984) (holding that in the case of a sale f.o.b. the mine, the seller of ores can treat the entire sales price as gross income from the property); cf. Southwestern Portland Cement Co. v. United States, 435 F.2d 504 (9th Cir. 1970) (illustrating a situation where profit had to be attributed to a particular transportation arrangement).

If a broker buys minerals and then resells them, the price the broker pays the miner constitutes the gross income from the property. However, if a broker sells the minerals on behalf of the miner, does not acquire title, and does not guarantee the purchaser's payment, any commission paid to the broker by the miner (although a deductible sales expense) does not need to be deducted in calculating gross income for purposes of depletion. 26 C.F.R. § 1.613(4)(e)(2) (1997); Rev. Rul. 75-115, 1975-1 C.B. 178.

101. 26 C.F.R. § 1.613-4(b) (1997). See also Dow Chemical Co. v. Commissioner, 433 F.2d 283 (6th Cir. 1970). See, e.g., Dravo Corp. v. United States, 348 F.2d 542 (Ct. Cl. 1965). Controversies still arise regarding new technologies that did not exist when the list was created. See, e.g., Ranchers Exploration & Development Corp. v. United States, 42 A.F.T.R. 2d 78-5561 (D.N.M. 1978), aff'd, 634 F.2d 487 (10th Cir. 1980) (treating a new process as
process is used after the ore has gone through a manufacturing process, the listed process will not ordinarily qualify as a mining process unless this treatment would result in discrimination between similar producers of the same mineral.\textsuperscript{102}

If the representative field market price cannot be determined pursuant to the basic regulations or is unrealistic, then a constructive gross income may be determined by the "proportionate-profits" method,\textsuperscript{103} a method which determines gross income from the property by allocating profits between mining and manufacturing activities.\textsuperscript{104} Under this method, the basic assumption is that each mining process and manufacturing process earns the same percentage of profit.\textsuperscript{105} In the case of oil and gas, however, courts have generally rejected the use of the proportionate-profits method.\textsuperscript{106}

E. Conclusion

The above discussion illustrates how depletion "reform," when coupled with case law supporting the notion that royalty (and production
taxes) may be calculated on the intrinsic value of oil or gas at the wellhead, has encouraged producers to shift profits downstream and costs upstream to minimize royalty liabilities. Accordingly, courts that allow lessees to work-back to the wellhead when calculating royalties under typical gas royalty clauses should appreciate the need to carefully scrutinize the calculation of the deductions.

Moreover, a review of depletion cases reveals that disputes over the calculation of percentage depletion closely parallel current disputes over royalty calculations. A key difference is that, in depletion disputes, producers desire a high production valuation to maximize the depletion allowance, whereas in royalty disputes, they desire a low production valuation to minimize royalty obligations. Nevertheless, the manner in which the tax code, tax regulations, revenue rulings, and case law have dealt with the calculation of gross income for depletion purposes is instructive in dealing with royalty valuation cases. The older hard-mineral depletion cases that conclude that depletion should be calculated at the point where the ore becomes a first-marketable product are especially helpful. This first-marketable product approach was used in the absence of specific regulations that addressed valuation in more detail. Royalty clauses suffer from a similar lack of detail.

In addition, the use of a proportional-profits method in calculating gross income from a mine in the absence of a representative field market price might serve, with proper modification, as an alternative to the work-back approach used in determining wellhead values in many royalty

107. Dr. Stephen L. McDonald, Professor Emeritus, The University of Texas at Austin, a leading oil and gas economist, responded to my request for a review of my thesis as follows:

It is . . . obvious that if the royalty base had not been clearly specified in the lease, a dispute is inevitable. . . . If, for instance, the lessee has some tax reason for transferring profits from one phase in a vertically integrated operation to another, then he might wish to use a royalty base most accommodating to his purposes. It used to be claimed by downstream operations in the oil industry, such as marketing, when operators were entitled to percentage depletion on the market value of extracted oil and gas, that companies deliberately transferred profits from downstream phases to the production phase by artificially raising the transfer price from the latter phase to the next one (refining). To get away with this with the IRS, they would have had to base royalties on the same price. When integrated companies lost the percentage depletion privilege . . ., they would have been motivated to interpret any vague royalty base as being the lower of two alternatives, since they could no longer benefit tax-wise from the higher one.

Letter from Dr. Stephen L. McDonald, Professor Emeritus, The University of Texas at Austin, to Owen L. Anderson (January 25, 1996).

108. Anderson, Figures Don't Lie, supra note 2.
cases. Of course, the use of the proportionate-profits method in a royalty case would require the careful calculation of total costs, including all costs of lease acquisition, exploration, drilling, completion, production, and marketing. Because of the substantially higher risk associated with exploration and production operations (such as the risk of drilling dry holes and unprofitable producing wells) the presumed rate of return for exploration and production operations would have to be substantially higher than the rate used for less risky post-wellhead activities.

III. THE LEGAL HISTORY OF "ROYALTY": PROPERTY OR CONTRACT?

A. Introduction

A 1995 article, arguing that the implied covenant to market should not be broadened to deny the deductibility of post-wellhead costs for purposes of royalty valuation, contained the following statements:

The landowner's royalty, like the royalty on gold and silver due the Crown under English common law, is understood to be reserved portion of the actual minerals extracted by the lessee. In other words, it is 'a share of production, free of expenses of production.'

...As in any commercial context, the common law relationship between the lessor and the lessee can be altered by private contract ... but there is something in the nature of the property right itself—something in the nature of the "bundle of sticks" that is a royalty that answers the question: The lessor's percentage is a percentage of what? Consistent with the sharing arrangement with the Crown that gave the "royalty" interest its name, the most obvious answer is that the lessor's royalty entitles the lessor to a share of the produced mineral in its natural state, after the mineral has been brought to the surface by the lessee.

109. For discussion of the work-back method, see generally id.
110. A modified proportionate-profits approach would be preferable to the unorthodox work-back approach (which was really a ratemaking approach) taken by the district court in Piney Woods Country Life School v. Shell Oil Co., 539 F. Supp. 957, 963–65 (S.D. Miss. 1982). The court allowed the lessee to deduct all post-wellhead costs plus a 15% rate of return, after taxes, resulting in almost no value for the raw sour gas at the wellhead. This approach recognized no rate of return for the exploration and production operations even though these operations were far riskier.
111. Williams et. al., supra note 2, at 12-4, 12-5.
Although these statements were largely made without citation of authority, the notion that royalty is inherently defined by property-law is not an unreasonable assumption.\textsuperscript{112} I noted in a 1981 article that property principles could be used to address the question of post-wellhead costs.\textsuperscript{113}

A property law approach to royalty may be illustrated as follows: Suppose a lessor grants an oil and gas lease "for so long as oil is produced" retaining a 1/8 \textit{in-kind} oil royalty. In Texas and several other states, the lessee would acquire a fee simple determinable estate in the working-interest oil in place beneath the property. In Oklahoma and in most other states, the lessee most often would acquire a \textit{profit a` prendre}, i.e., the exclusive right to explore and produce any oil that may lie beneath the property, for the duration of a determinable fee.\textsuperscript{114} Both of these interests would be subject to the lessor's right to receive production royalty in kind. A basic issue is: When, or at what point in the production stream, is the lessor entitled to claim 1/8 of the production? The "property" answer is: The lessor is entitled to claim the royalty share when the oil is captured at the wellhead, i.e., the point at which the oil itself is converted from real to personal property. At that point, the lessor would be entitled to claim 1/8 of the total oil production as the lessor's personal property. Thus, the lessor would be implicitly responsible for all costs associated with handling the royalty oil from that wellhead point.

This property approach can also be used with gas, except that the lessor usually retains a money royalty rather than an in-kind royalty. Nevertheless, consistent with the approach taken regarding oil, under a property analysis the lessor would logically be entitled to claim 1/8 of the value of the gas at the wellhead. (Again, this is the point at which the gas itself is captured and converted from real to personal property.) As with oil, the lessor would be implicitly responsible for a proportionate share of all costs associated with the handling of the gas from that wellhead point. Accordingly, if the lessee incurred expenses in the post-wellhead handling of the gas, it implicitly follows that the lessor should absorb, through royalty valuation, a proportionate share of such expenses.

\textsuperscript{112} Judicial support for this notion can be found in several cases. See, e.g., Atlantic Richfield Co. v. State, 262 Cal. Rptr. 683, 688 (Ct. App. 1989); Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 240 (5th Cir. 1984), cert. denied, 471 U.S. 1005 (1985), aff'd in part, rev'd in part on other grounds, after remand, 905 F.2d 840 (5th Cir. 1990); Wall v. United Gas Pub. Serv. Co., 152 So. 561, 563 (La. 1934).

\textsuperscript{113} Anderson, \textit{David v. Goliath}, supra note 2, at 1114-16.

\textsuperscript{114} Note the distinction here between a "fee simple determinable estate" (which describes both a possessoriy estate in land and its duration) and the "determinable fee" (used here to describe the duration of a nonpossessoriy interest). See Shields v. Moffitt, 683 P.2d 530 (Okla. 1984); \textit{Discussion Notes}, 81 OIL & GAS REV. 159. See generally 2 KUNTZ, supra note 6, § 26.2 at 324-25 (1989).
An intriguing question is whether “royalty” has actually ever been viewed in this simple property sense. If modern royalty law is, in part, to be based on how royalty was viewed historically, the actual historical treatment of royalty should be ascertained. The following summarizes what I was able to discover from an examination of several available secondary authorities.115

B. Legal History (Other Than the United States)

Historically, “royalty” is simply that which is due the Crown, Sovereign, or landholder. In the context of minerals, royalty is simply a share of mineral product payable in kind or in value to the Crown, Sovereign, or landholder. In its most common form, royalty served as a payment for the right to mine; however, in some instances it was essentially a tax, and in other instances, it was little more than a bribe. In England, a royalty share was commonly remitted, either in kind or in value, to Lords who held lands under grant from the King as payment for the right to mine and market minerals.116 Based upon my study of available secondary sources, there is no evidence that the established point for the remittance of royalty was ever at the mouth of a mine or that royalty was actually remitted the instant that raw ore was converted from real to personal property. In other words, there is no “property” definition of royalty, and there is no evidence that royalty was remitted in the form of “a share of the produced mineral in its natural state, after the mineral was brought to the surface . . . .”117 Rather the royalty entitlement depended entirely upon the language of the governing ordinance, decree, or contract.

The following excerpt from a seminal history on mining118 briefly describes some of the mining customs of ancient Greece at the silver mines of Laurium, circa 480 b.c. following the defeat of the Persians.

The Mines of Laurium were the property of the State, which, however, did not operate them on its own account, but leased them to its citizens, either as individuals or as groups of adventurers, who paid a premium, usually one talent, for the

115. Primary authority (actual contracts, statutes, and decrees) were either not available or available only in a language other than English. Necessarily, I am presuming that these secondary sources and translations are reasonably accurate.

116. Customarily, an additional share (a “tithe”) of mineral production was also remitted to monasteries in return for prayers on the miner’s behalf.

117. Williams et al., supra note 2, at 12-5.

118. T.A. RICKARD, MAN AND METALS, A HISTORY OF MINING IN RELATION TO THE DEVELOPMENT OF CIVILIZATION (1932).
lease, and also a rent, or tribute, of one twenty-fourth (about 4 per cent) of the output, in bullion. \(^{119}\)

The remittance of royalty in bullion indicates that royalty was paid in pure silver (in a condition suitable for making jewelry, silver utensils, and coin), not in raw ore. \(^{120}\)

The following provisions as translated from Roman Law \(^{121}\) indicate that royalty was payable by parties engaged in quarrying marble.

In accordance with the law previously issued, all persons shall have the right to work private quarries, to cut out and cut up stone, if a rich vein of marble is available to them, with the provision that a tenth part shall be assigned to the account of Our fisc and a tenth to the owner of the land. The remainder shall become the property of those operating the quarry, according to the tenor of the aforesaid law, and the operators shall have the license to sell, to give, to transfer such stone, wherever their desire may persuade them. \(^{122}\)

Note that the Roman government and landowner each received one-tenth of the cut marble in kind for a total royalty burden of 20%. The law’s reference to the sale and transfer of cut stone verifies the fact that once quarried and cut, marble becomes a useful, and hence marketable, product. Royalty was due on this marketable product.

The following are excerpts from mining law applicable in New Spain in the reign of Charles III in the late 1700s.

Section III. Be it understood that this grant [of mining rights] is made upon two conditions: First, that they (my subjects) shall pay to my Royal Treasury the proportion of metal reserved thereto; and secondly, that they shall carry on their operations in the mines subject to the provisions of these

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\(^{119}\) Id. at 370—71.

\(^{120}\) Gold or silver in the lump, as distinguished from coin or manufactured articles; also applied to coined or manufactured gold or silver when considered simply with reference to its value as raw material. \(1 \) THE COMPACT EDITION OF THE OXFORD ENGLISH DICTIONARY 293 (1971).

\(^{121}\) CLYDE PHARR, \(THE \) THEODOSIAN CODE AND NOVELS AND THE SIRMONDIAN CONSTITUTIONS, Book X, Title 19 (1952).

\(^{122}\) Augustuses to Cynegius, Praetorian Prefect, given on the third day before the nones of October at Constantinople in the year of the consulship of Richomer and Clearchus, October 5, 384. Id. at 284. Earlier laws levied what appears to be a tax on mining that was payable at a fixed rate. See Emperors Valentinian and Valens Augustuses to Cresconius, Count of Minerals and Mining, given on the fourth day before the ides of December at Paris in the year of the consulship of Valentinian and Valens Augustus, December 10, 365, and Augustuses to Germanianus, Count of the Sacred Imperial Largesses given on the sixth day before the ides of January at Rome in the year of the consulship of Lupicinus and Jovianus, January 8, 367. Id. at 283—84.
Ordinances, on failure of which, at any time, the mines of persons so making default shall be considered as forfeited, and may be granted to any person who shall denounce them accordingly. 123

Two preceding sections established the royal ownership of all mines in New Spain 124 and provided for the granting of mines to the King's subjects for exploitation. 125 This grant, however, was conditioned upon payment of a proportion of the metal to the Crown. Although this language does not clarify exactly what a "proportion of metal" means, early Spanish laws provided for net-profits royalties:

Inasmuch as we are informed that these our kingdoms abound and are rich in minerals; therefore as an act of grace and favor to our said kingdoms and the inhabitants and residents of the cities and incorporated villages and other places and to persons connected with the church, notwithstanding that by ourselves and our royal ancestors in those privileges which have been granted as a matter of favour there has been reserved by us minerals of gold, silver, and other similar metals; it is our pleasure that henceforth all said persons and all others whomsoever, of these our said kingdoms, may search for, examine, and may excavate their said lands and estates and remove from them said minerals of gold, silver, quicksilver and tin, stone and other metals; and that they may search and excavate for minerals in all other places whatsoever, not prejudicing in their searches and excavations, the rights of other persons, and acting with the permission of the owner; and all the minerals which shall be thus found and extracted shall be divided as follows: First, there shall be delivered and paid therefrom to the person who extracted the mineral all expenses of excavating and extracting, and of the remainder, the said expenses having been deducted, the third part shall belong to the person extracting the mineral, and the other two parts to ourselves. 126

123. King Charles III, Mining Law of Spain, Royalty Ordinances for the Director, Regulation, and Government of the Miners of New Spain, Madrid (1783) in 1 John A. Rockwell, A Compilation of Spanish and Mexican Law, in Relation to Mines, and Titles to Real Estate, in Force in California, Texas and New Mexico; and in the Territories Acquired Under the Louisiana and Florida Treaties, when Annexed to the United States 49 (1851).
124. Id.
125. Id.
This excerpt reveals that the royalty due the crown was subject to a deduction of excavation and extraction costs. No doubt, the crown was willing to allow a deduction for these expenses because it had reserved a 2/3 royalty share. Thus, the royalty due the Crown did not inherently mean a share of production, free of expenses of production. By the mid-1500s, however, most likely due to varying efficiencies among miners, this net-profits approach was abandoned in favor of a cost-free royalty on silver (ranging from 1/10 to 1/2, depending on the yield) and on gold (1/2):

III. If the ores which shall be raised from the said mines shall yield at the rate of a marc and a half, or 12 ounces, per quintal of silver lead, or under, they shall pay us the tenth part of the silver which shall be raised from such mines and ores, without any deduction whatsoever for expenses, or on any other account, all which matters shall be at the charge of the persons who shall discover and work the said mines; and all that remains after deducting such tenth part, they may have and retain to themselves.

..... [Articles IV - VI increased the royalty share from 1/5 to 1/4 to 1/2 as the quality of the ore increased.]

VII. From the mines of gold, whatever the quality, quantity or richness of their ores shall or may be, they shall pay us one moiety [1/2] of the gold raised, without any deduction for expenses, and the persons who shall discover and work them may retain the other moiety to themselves. And this is to be understood of every description of gold ore, however worked, and in whatever manner procured, whether from mines, from streams, or elsewhere.

..... [Articles VIII - X addressed the payment of royalty on abandoned mines that were reopened and reworked. Articles XI and XII addressed royalty on low grade ores and the leftover by-products of refining and smelting.]

XIII. And it is to be understood that all the proportions above declared to be payable to us out of the produce of the mines above described, both new and old, and of the heaps and rubbish and slag, are to be paid to us at the refining houses and smelting works which we shall establish for the purpose of refining, in silver, and not in ore, nor in silver-lead; and that our proportion of the poor lead and copper shall be payable in ingots, and of the antimony in ore, all of the same kind and
quality as the proportion remaining to the owners, and clear of all expenses.\footnote{127}

Note that royalty was due at the smelter or refining works, not at the mine, "in silver, and not in ore, nor in silver-lead; and that our proportion of the poor lead and copper shall be payable in ingots, and of the antimony in ore...\footnote{128} Thus, at the very least, the miner was responsible for extracting, processing, and transporting the ore to the refining and smelting works. Although it does appear that the Crown established the smelting and refining works, there is no indication how they were operated or whether the miner had to absorb these costs, other than the express statement that royalty was due "clear of all expenses."\footnote{129}

The mining law of the United States was greatly influenced by English common law and by the customs and practices of the lead miners in Derbyshire.\footnote{130} The development of mining law, beginning with the Inquisition of Edward I (a.k.a. Edward "Longshanks") at Ashbourne in 1288, is summarized in the following discussion:

A vein, when first discovered, had to be 'freed', that is, application had to be made to the Barmaster, (a Crown official who deals with all lead mining queries and customs), to register the name of the new vein in his book; at the same time two 'free dishes' of ore being paid to him by the miners. These dishes represented the initial payment due to the owners of the mineral duties.

The payment of the two dishes to the Barmaster enabled the miners to work for a distance of two meers [generally 32 yards in length] in their new vein, and as deep as their resources would allow, the width of the working being governed by the width of the vein itself. The third meer was called the Lord's Meer and belonged exclusively to the owner of the mineral duties. Since the year 1690, the mineral duties in the High Peak have been leased from the Crown by the Dukes of Devonshire... The third meer, Lord's Meer, could either be bought by the miners, or they had a right to work through it, but in this latter case could not sell any ore they

\footnote{127. Law of July 10, 1559, as modified by Philip II in 1584, \textit{in} \text{1 ROCKWELL, supra note} 123, at 144 - 47 (emphasis added).}
\footnote{128. \textit{Id.} (emphasis added).}
\footnote{129. \textit{Id.} (emphasis added).}
\footnote{130. \textit{See generally John C. Lacy, Going with the Current: The Genesis of the Mineral Laws of the United States, 41 ROCKY MTN. MIN. L. INST. 10-1, 10-16 to 10-23 (1995).}}
obtained in so doing. If they decided to purchase the Lord’s Meer outright, then the Barmaster and member of the Barmoot Court were called to descend the mine, view the vein, and place a valuation on it. . . . After the miners had worked, or worked through the Lord’s Meer, they could free as many subsequent Taker meers as they wished. These had to be kept at work otherwise they could be ‘nicked’ or counterclaimed by other miners wishing to work the vein.

In addition to the ‘freeing dishes’ paid by the miners to the owners of the mineral duties, other Royalties were also payable. These included both ‘Lot’ and ‘Cope’ and also Tithe. . . . Briefly, the Lot was taken as a certain fraction of the dressed ore. Normally this amount was 1/13th, but at times this was altered by the Mineral Lords, sometimes on account of the low price of lead which made mining less profitable than usual. The Cope was generally paid by the Lead merchants and was in places 4d. [dishes] per load, in others 6d. [dishes] per load. The Cope was taken as payment in lieu of the Mineral Lord having first right to purchase the ore. Sometimes this Cope payment was rented out to one of the Barmasters. Nine dishes were reckoned to equal one load, and the load varied in weight, dependent upon the quality of the ore. . . .

The following excerpts from another history of the lead miners of Derbyshire describes the mining rents and royalties as follows:

The Barmaster had to be present when the ore was measured, but not when it was dressed or sold. He . . . received the Freeing dish for the Lord of the Field, the Dishes for the duty of lot, also the payment of the duty of cope. . . .

After the miners had raised an amount of ore to the surface and had dressed it, under severe penalties none must be sold or taken away before the Barmaster or his Deputies had measured it and extracted lot, which was the duty payable to the owner of the mining rights. . . .

131. PEAK DISTRICT MINES HISTORICAL SOCIETY, LEADING MINING IN THE PEAK DISTRICT 10-12 (1968) (emphasis added). One freeing dish held 14 Winchester pints. Id.
The Barmaster measured the ore in the wooden Dishes sized to the official Dish, setting aside every thirteenth for lot, and entering the amounts in a book.

Before being measured the ore always had to be washed and dressed, or 'made merchantable' as it was called. Theoretically the lot was every thirteenth Dish and this was the amount generally paid up to the eighteenth and nineteenth centuries when the mines became deeper and mining more difficult. Then the miners often appealed to the owners of the duties which were sometimes reduced in order to keep the mines from closing. Varying amounts actually were paid, ranging to as little as 1/40th instead of 1/13th.

Cope can be an apparently confusing word. It is used with three meanings, but generally the context makes the meaning clear. Cope in the far older sense of the word was the duty of 4d. or 6d. a load, paid to the Lord of the Field, usually by the buyer (smelter). This was a pre-emption, allowing the miner to sell his ore for smelting wherever he pleased. Cope as payment was not mentioned in 1288, but pre-emption was indicated by the King having the right to buy the ore 'before all others if he will give as much as it could be sold for to another.' Seven years later miners in the King's Field of the High Peak were paying 4d. a load for cope, with 6d. a load in the Low Peak.

Note that the ore had to be dressed and washed before the lot was taken. This process included the grinding of the ore (to separate the ore from the stone) with a subsequent washing, leaving only the ore, a product that could then be sold to a smelter/buyer. Although the royalty dishes were taken from the washed ore and not from the final smelted product, the ore itself was a marketable ('merchantable') product.

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133. The "tithe" is explained as follows:

The payment of lead ore tithe was greatly resented by Derbyshire miners. The revolt against this which came to a head in the seventeenth century originated in the previous century. In earlier times lead ore tithe had a religious object, for it had been said with truth that 'tythes were given by the myners for prayers to be made for them evening and morning'. At the Dissolution of the Monasteries in the 1550's laymen became possessed of tithes to a far greater extent than formerly, so that they became a hated tax for which the miner considered he received nothing in return, thus extending his resentment to the clergy. As it was stated at Wirksworth in
The mining customs of Cornwall and Devon provided for the payment of a royalty on tin. This royalty was called toll tin and is described in the following excerpt:

Toll tin was the render or counterpart due to the freeholder when his land was mined for tin by a bounder or his lessee. It resembled a rent reserved by lease of land in that it was payable whether or not the land was worked profitably, but it was not a contractual render like rent, and so in strict law the freeholder could not sue the bound owner for breach of contract if it were not delivered. Nevertheless in equity the Vice-Warden's court allowed the freeholder to sue for damages (... the value of his share of the tin broken) just as though he had granted a lease or sett to the bounder, and if the tin had been sold he was also allowed to sue for his share of the proceeds or for the account of the proceeds so that payment of his share might be directed. 

... In practice, freeholders took toll tin in the form of a share of the proceeds of sale of the tin ore, but, if they wished, they could insist on receiving a share of the black tin as soon as it was washed, and they would then arrange for sale of their share themselves.

In Devon the freeholder of privately owned land and his tenants were entitled to receive one-tenth of the profit of tinworks on their land as compensation for damage done to the surface. Unlike toll tin, which was a share in the produce or gross proceeds of the mine, this entitlement was to a share of the net proceeds, so that if the cost of working the mine exceeded the proceeds of sale of the tin ore broken, the freeholder and his tenants received nothing.\(^{134}\)

Note that the tin royalty was paid on the "gross proceeds" of sale of the tin ore and was "payable whether or not the land was worked profitably." In other words, tin royalty was due on a marketable product. And in Devon,

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\(^{1665}\), when the miner gave the Freeing Dish and paid lot he obtained the right to work his mine, with the right to 'have timber in the King's wastes ... and egress and ingress from the highways to their Groves or Mines'. Cope brought freedom with regard to smelting, so that for all these he received something in return, whereas for tithe he received nothing.

\(^{Id.}\) at 103—04. From this excerpt, it appears that the tithe (which is not really a "royalty") was payable on net profits.

\(^{134}\) ROBERT R. PENNINGTON, STANNARY LAW: A HISTORY OF THE MINING LAW OF CORNWALL AND DEVON 87—89 (1973) (emphasis added).
the freeholder also received compensation for surface damages based upon the mine's net profits.

Early mining leases in Cornwall and Devon are summarized in the following excerpt:

The form of mining setts or leases in the sixteenth and seventeenth centuries was derived from the grants of mining rights made by the kings of England from the thirteenth century onwards. At first most of these royal grants had been made gratuitously to members of the royal family or to court favourites, but occasionally they were also made as commercial transactions in return for a fraction of the ore broken or, less frequently, a money payment. The earliest example was a grant of Henry III to Adam de Greyvill and John Silvester in 1263 by which the king granted (concessimus) the royal mines of gold, silver, copper, lead and all other metals in Devon to hold during the king's pleasure, but the grantees had to answer at the royal exchequer for the produce thereof . . . . The grantee's share of the metal produced was not specified, but clearly they were intended to receive more than a fee or wage. Nearly 100 years later, in 1358, Edward III granted and leased (concessit et dimisit) to John Balancer and Walter Goldbeter the royal mines of gold, silver and copper in Devon with liberty to dig in all places they thought fit but not in gardens or under houses; the grant was made for two years at a rent of 20 marks for the first year and the render of one-fifth of the metal coming from the mines during the second year (presumably in the form of ore) . . . .

After a further century the royal grant had developed into the more sophisticated form that private grantors imitated in the sixteenth century. In 1452 Henry VI granted to John Botright, the governor of the king's mines of gold and silver in Devon and Cornwall, all the mines of copper, tin and lead in those counties from which gold might be extracted to have and hold to his own use so long as he was of good behavior in his office of governor and rendered to the king and his heirs one-tenth of the refined gold, silver, copper, tin and lead after deducting the expenses of smelting. . . .

The earliest surviving mining lease or sett granted by private persons in Cornwall and Devon was of tin bounds in Polgooth (St. Austell) and is dated 29 September 1666. . . .

. . . A render of one-tenth of the ore broken was reserved to the grantee in the lease of 1666, and this was provided for by the reddendum clause which followed the
The grantor's share of ore was delivered by the grantee in the form of black tin, or, in the case of leases for mining other metals, in the form of crushed ore ready for smelting. The cost of smelting this share was borne by the grantor, not the grantee, but in practice the grantor would either sell his share to a smelter or deliver it... for smelting on commission and take a tin bill... as security. It was an obvious convenience for the grantee to arrange for the sale or smelting of the grantor's share of ore while making the arrangements for his own share, and the practice grew up in the eighteenth century of the grantee accounting to the grantor for the sale price or the market value of the grantor's ore in cash instead of delivering ore in specie. This was particularly sensible with copper ore, which was always sold to the smelters after copper ticketings or auctions of copper ore were introduced in 1725. When smelters ceased to smelt tin on commission in the 1830s, legal draftsmanship at last caught up with this century-old practice, and grantees henceforth obliged themselves to pay the grantor's render in cash.

These excerpts indicate that the ore was sometimes sold prior to smelting and thus "marketable" prior to smelting. Note how the marketing practices of miners closely parallel the practices of modern-day oil and gas lessees. For example, compare the grantee's marketing of the grantor's share of ore on the grantor's behalf (even though the grant reserved ore in kind) with the common practice of oil and gas lessees who market the lessor's royalty oil on the lessor's behalf (even though the royalty oil is often reserved in kind). And compare the practice of arranging for the smelting of ore on commission with the practice of gas producers who arrange for the extraction of liquids from wet gas by a third party on a similar basis. Finally, note that, where the ore was smelted prior to sale, the grantor shared proportionately in the smelting costs, just like the oil and gas lessor shares proportionately in the cost of extracting liquids from wet gas.

Rockwell offers the following summary of the mining laws and customs of England in 1850:

The rents made payable in respect of metalliferous mines are almost invariably proportioned to the quantity of ore actually raised, and without any stipulated certain rent in money. This rent is called the duty ore, or the lot ore, or the lord's dues. It is a common practice to stipulate that the rent shall be paid in money according to the market price of the day, or by delivery of the metals in a manufactured state. Thus,
in demises of lead mines the reservation may consist of a
certain quantity of smelted lead and of the silver actually
extracted from the ore. In all such cases, an adequate allowance
is made in the amount of reservation for the expenses saved to the
lessee in selling or smelting his proportion of the produce. But it is
a frequent practice to stipulate for the lord's proportion of mineral
to be rendered when it has been washed and cleansed by the lessee,
and before it has undergone any process of manufacture, by which its quality is changed. The proportion to be rendered to the
lessor differs not only with respect to the nature of the metals
and substances which are discovered, but also to the
circumstances under which they are produced. It would be
impossible, therefore, to lay down any general rule.\textsuperscript{136}

According to this digest, the "common practice" was to remit royalty by the
"delivery of metals in a manufactured state." However, it was also a
"frequent practice" to pay royalty after the mineral had been "washed and
cleansed."

In summary, while there is a certain logic to the property argument
offered in the introduction to this section, legal history does not support the
argument. Rather, these excerpts reveal that royalty obligations were never
defined or determined as a matter of property law based upon the physical
severance of ore from the earth. Royalty simply means a share due the
sovereign or the landowner. The share due depends upon the express
language of the decree or grant, but most often royalty was due on a
marketable product free of expense. Rather than looking to property law,
the royalty due was determined by the language of the governing ordinance
or contract. Although royalty was occasionally paid on net profits, royalty
was most commonly due free of cost after the mineral had been extracted
and processed into a marketable product, and often after it had been
transported from the mine to a smelting or refining facility. None of these
excerpts supports the notion that royalty was payable either in raw ore, or
on the intrinsic value of raw ore, as extracted from the mine. For the most
part, any allowance for the cost of mining and handling the mineral prior
to its actual sale and any allowance made for low-grade ore was reflected
in the amount of the fraction of the reserved royalty share, not through the
deduction of post-extraction costs.

\textsuperscript{136} 1 Rockwell, supra note 123, at 558–59 (emphasis added). Although not specifically
dated, this commentary was a current analysis of the common law at that time, circa 1850.
In the earliest American royalty cases, the courts did not rely on an inherent property-based definition or classification of royalty. Instead, courts construed the express language of the royalty clause to determine what was actually due the lessor.\textsuperscript{137} In construing royalty clauses, however, courts did not strictly adhere to the specific anticipatory language of the royalty clause if such adherence would lead to an unreasonable result. Rather, as the following cases illustrate, the courts generally construed royalty clauses as a sharing arrangement in light of the parties' reasonable expectations and in light of the often unanticipated circumstances that gave rise to the dispute.

Many early American mining leases required royalty to be paid at a fixed price per quantity of produced ore, e.g., 10¢ per ton. For example, in \textit{Wright v. Warrior Run Coal Co.},\textsuperscript{138} a coal lease provided that the lessor was to receive 15¢ a ton for all coal "mined" that was larger than "chestnut" coal and half price (7.5¢ a ton) for "chestnut" coal. No royalty was due on smaller-sized coal. After extracting the coal, it was separated by size, and some of the coal was crushed as expressly contemplated by the lease. The various sizes ranged from "lump" coal (the largest), "steamboat," "broken," "egg," "stove number three," "stove number four," to "chestnut" (the smallest marketable size at the time the lease was made). Initially, the production of chestnut coal did not exceed 15\% of the total mine output; however, soon after the lessee commenced mining, the demand and price for larger-size coal fell, and the demand and price for smaller-size coal rose.\textsuperscript{139} Moreover, coal smaller than chestnut ("pea" and "buckwheat" coal), which had previously been discarded, became marketable.\textsuperscript{140} Thus, to meet the demand for smaller-size coal, the lessee crushed more of the larger-size coal into smaller sizes.\textsuperscript{141} This resulted in a higher percentage of coal sized as chestnut and smaller grades. The master found, in accord with the lessee's argument, that the lessee had crushed the coal to meet a changed

\begin{figure}
\begin{itemize}
\item \textsuperscript{137} In the broadest sense, several early cases classified the fixed-price royalty payable for coal as additional purchase money due for the sale of the coal reserves to the miner; these cases gave the lessor/vendor a lien on the coal not mined and removed to secure payment of this purchase price. \textit{See}, e.g., \textit{Manning v. Frazier}, 96 Ill. 279 (Ill. 1880); \textit{Fairchild v. Fairchild}, 9 A. 255 (Pa. 1887); \textit{Williamson v. Williamson}, 4 S.W.2d 392 (Ky. 1928). On the other hand, where the lessor reserves a portion of the minerals produced, case law has tended to classify the royalty as an "exception" from the grant. \textit{See}, e.g., \textit{Pierce Petroleum Co. v. Empire Gas & Fuel Co.}, 17 F.2d 758 (5th Cir. 1927).
\item \textsuperscript{138} 38 A. 491 (Pa. 1897). My summary of the facts in this case have been somewhat simplified.
\item \textsuperscript{139} \textit{Id.}
\item \textsuperscript{140} \textit{Id.}
\item \textsuperscript{141} \textit{Id. at 494.}
\end{itemize}
\end{figure}
market, not to avoid royalty; that the parties expressly intended that royalty
on chestnut coal was to be 7.5¢ a ton; and that no royalty was due on coal
smaller than chestnut. Nevertheless, the master concluded that the lessee
owed royalty of 15¢ a ton on all chestnut coal produced in excess of the
mine's historical output of 15%, and owed 15¢ a ton on all pea coal in excess
of the mine's historical output of 9%. The Pennsylvania Supreme Court
affirmed, concluding that the parties' agreement was made based upon a
continuation of the coal market then existing at the time the lease was made.
The court justified its view by reasoning that a ruling in favor of the lessee:

[L]eads to an unreasonable conclusion, and one that works
dpalpable injustice to the landlord; for, if payment under the
contract be measured by the preparation of the coal to any
size which defendant thinks may suit the market, then if the
market demand is mainly for pea and buckwheat, and nearly
all of it be crushed to those sizes, plaintiffs [lessors] are
entitled to almost no royalty.

Wright is an early "reasonable expectations" case that views royalty
as a sharing arrangement. The opinion illustrates that American courts have
not looked to property law for an inherent definition of royalty nor have
they applied a strict-constructionist interpretation to royalty provisions.
Rather, the royalty obligation is determined by a reasonable contract-law
construction of the royalty clause in light of the facts and circumstances
existing at the time the lease was made and in light of the often
unanticipated circumstances that gave rise to the dispute, such as changes
in the coal market that the parties did not foresee. In sustaining the views
of the master, the Wright court construed the coal royalty provision in light
of the parties' reasonable and probable intent, i.e., what the royalty clause
would have expressly provided if the parties had realized how the coal
market would evolve.

The court also affirmed the master's finding that the word "mined,"
as used in the royalty provision, meant coal that was mined, "sold and
marketed," and did not include coal consumed in the operation of the mine
itself. In Wright, the court concluded that the parties reasonably expected
that royalty was due only on coal that was actually sold and marketed, not
just "mined." In other words, the court treated "sold and marketed" as part
of the meaning of "mined" — a construction that, in this case, worked to the

142. Id.
143. Id. at 495.
144. Id.
145. Id. at 494.
lessee's benefit. Construing the word "mined" as meaning mined, sold, and marketed, is analogous to construing the word "produced" as including the sale and marketing of oil or gas. Indeed, much of the handling of the coal and its preparation for market occurred after the coal had been extracted from the mine, and the lessor was not charged, through royalty accounting, for the cost of these post-extraction activities. In my review of flat-rate royalty cases, I found no cases where a lessee was allowed to take a deduction for post-wellhead or post-mine-mouth costs. Although this is not surprising, why then should the word "mined" (or "produced") necessarily take on a different meaning if it is changed to 15%?

In Audenried v. Woodward, the plaintiffs/lessors leased an existing coal mine, and the lessee assigned the lease to the defendant. The lessors and the defendant agreed that the lessors would purchase all of the mined coal but "retain in their hands an appropriate portion of the purchase money sufficient to compensate for the rent of the mine, which rent was based upon the quantity taken out..." and retain moneys necessary to pay all mining expenses, and account to the lessee for the balance. As the defendant was also indebted to the lessor for a loan, this unusual arrangement was apparently due to the defendant's financial difficulties. When the lessors brought suit to recover this debt balance, the defendant disputed certain costs charged to its account by the lessor, including the cost of a "patent coal-breaker" - a machine used to crush the coal after it is brought from the mine. In rejecting the defendant's contentions, the court stated:

146. In cases where the lease provided for the payment of a fixed annual royalty for the balance of a fixed term following the drilling of a well or the opening of a mine, a "reasonable expectation" analysis has also worked to the benefit of a lessee. In these cases, the courts found that the obligation to continue to pay royalty for the balance of the fixed term was implicitly conditioned upon continued production from the well or mine. See also Williams v. Guffey, 35 A. 875 (Pa. 1896). See, e.g., Hewitt Iron Mining Co. v. Dessau Co., 89 N.W. 365 (Mich. 1902) (holding that the specified "minimum" iron royalty was no longer payable once all of the iron had been mined even though the fixed term of the lease had not yet expired); McConnell v. Lawrence Gas Co., 30 Pittsb. L.J. (N.S.) 346 (1890) (holding the continued obligation to pay $500 per year for the balance of the fixed term was conditioned upon an "implied agreement or understanding... that the well... be and remain a gas well").

147. One possible exception, which I did not carefully research, is whether there are any cases where the lessee was allowed to deduct a severance tax from a flat-rate royalty. Such cases, however, would most likely turn, at least in part, on the construction of the taxation statute, rather than solely on the construction of the royalty clause.

148. 28 N.J.L. 265 (1860).

149. Id. at 266.

150. Id. at 268.
It satisfactorily appears, from the proofs, that it was the business of the tenant of a colliery, and not of the landlord, to provide a breaker for preparing the coal for market; and as the defendant could not obtain one on his own responsibility, but requested aid from the plaintiffs, all the payments which they made... for the construction of that machine, and for the expenses of furnishing it to the defendant, are proper items of charges in the accounts.\textsuperscript{151}

Although the court does not fully quote the applicable lease clauses, the court's holding places all expenses incurred in preparing the coal for market on the lessee. Thus, the case fairly stands for the proposition that, absent a contrary lease provision, the lessee bears the entire burden of preparing coal for market and implicitly rejects the notion that, as a matter of property law, royalty is payable as a share of the produced mineral in its natural state as it comes out of the mouth of the mine. Rather, the case supports the principle that royalty is due on a marketable product.

In \textit{Wolfing v. Ralston},\textsuperscript{152} the court construed a gold mining lease wherein the lessees promised to pay lessor "twenty percent of all the gold that they may take from said vein, lead, or lode, or from the angles or spurs thereof; that they are to work the same without expense to the [lessor]. . ."\textsuperscript{153} The lease further provided that if the lessees "should take, during any week, gold sufficient to more than pay for the back expenses of working the said mine, then the [lessor] . . . is to have one third of the gold they may get from said mine after paying said working expenses."\textsuperscript{154} Arguing that it was not required to deliver gold to the lessor until all mining expenses had been recovered, the lessee argued that it owed no royalty to the lessor because it had not mined enough gold to cover its expenses. The jury found that the lessees had not taken out sufficient gold to recover all mining expenses and thus concluded that the lessors were not entitled to any gold under the "one third" net-profits clause. The court, however, held that the lessor was entitled to royalty under the "twenty percent" clause because that royalty was payable regardless of whether the lessees had recovered their costs of mining.\textsuperscript{155}

This case, which distinguishes a cost-free royalty clause from a net-profits royalty clause within the same lease, illustrates that royalty can be either cost free or cost bearing, depending upon the wording of the royalty

\textsuperscript{151} Id. (emphasis added).
\textsuperscript{152} 61 Cal. 288 (1882).
\textsuperscript{153} Id. at 290.
\textsuperscript{154} Id.
\textsuperscript{155} Id. at 292.
In other words, the royalty obligation depends upon the language of the royalty clause, not on an inherent property-law definition of the royalty obligation.

In Maloney v. Love, the lessee promised to pay "as royalty, sixteen and one-half... per cent, on all net proceeds from all smelter and freight charges and mill returns on all ore of the value of fifty dollars... per ton or less." This base royalty increased in accordance with the value of the ore. The lease also provided that the lessors were to receive "an undivided one-fourth nonassessable interest... free from all expenses whatever... said one-fourth interest being the net proceeds from said ore taken from said lease." Citing the modifying clause—"from the net proceeds from said ore," the lessee argued that the "undivided one-fourth nonassessable interest" was intended to be a net-profits interest subject to a proportionate share of all mining costs. After determining that the words "nonassessable interest" meant "an interest against which no expense is chargeable," the court noted that the words "net proceeds... imply a deduction of something from gross proceeds." The court then concluded that "[i]t is manifest that, whatever the parties contemplated, it was not intended to include work upon the mine, because the interest was expressly exempted from liability on account of such work." Looking to other royalty provisions which also used the term "net proceeds," the court found the term to mean "... that freight charges and charges for treatment are to come out of the gross mill or smelter values, and what is left is the net proceeds." Thus, in accord with the express lease language, the royalty provisions were subject to a deduction for freight and smelting charges.

Like the previous case, Maloney illustrates that royalty can be either cost free or cost bearing, depending upon the wording of the applicable royalty clause, and implicitly rejects the notion of a property-law definition of the royalty obligation. Rather, the royalty payable depends upon the express language of the royalty provision. In reaching its decision, the court

156. See also Poterie Gas Co. v. Poterie, 36 A. 232 (Pa. 1897). Under the lease at issue, the lessee agreed to pay the lessor "1/3 of all the profits realized from oil or gas," found on the premises. The court concluded that the word profits was not equivalent to income, but meant the amount realized from sale of the production after deducting expenses. The case does not indicate whether the court was influenced by the amount of the fraction. See also Paxton v. Benedum-Trees Oil Co., 94 S.E. 472 (W.Va. 1917) (holding that where the lease provided for a 1/8th royalty plus a carried 1/16 working interest, the 1/16th working interest was a net profits interest).


158. Id.

159. Id. at 1029-30.

160. Id. at 1030.

161. Id.

162. Id.
within the meaning of that provision of the lease whereby one-eighth of all the oil so produced and saved is reserved to the [lessee].

It will further be seen that ... [as lessee] makes the judicial assertion that the plant, appliances, etc., ... were absolutely required by the lease, as the means of increasing the production of petroleum and of preventing [lessee's] ... land from being drained of that mineral, it contends ... , with equal earnestness, that the cost of that plant and appliances and many other charges, including operating expenses, should be charged against the casing-head gas and gasoline account.\textsuperscript{171}

"Considering the different positions thus assumed by the [lessee]."\textsuperscript{172} the court then concluded:

[W]e find nothing in this record which seems to impair the doctrine that no one is presumed to give, and hence nothing to warrant the belief that it was within the contemplation of the contract ... that [lessee] ... should be allowed to take ... gasoline ... or any other product of value, and give nothing in return."\textsuperscript{173}

The court decided that the lessor should be paid for the casinghead gas pursuant to the oil royalty clause\textsuperscript{174} and held that lessor was entitled to recover 1/8 of the value of the casinghead gasoline.\textsuperscript{175} Finally, the court refused to allow the lessee to deduct any charge for the additional expense it incurred in saving the gasoline, noting that "the treatment of the gasoline off the premises, at the blending plant ... [and] the additional expense of precipitating the gasoline ... [was] apparently trifling, and more than compensated by the greater value of the product."\textsuperscript{176} On rehearing, the court again stated that "[t]he comparatively small expense ... for machinery used ... in saving casing-head gasoline, would not warrant us in charging the ... [lessor] with any part thereof."\textsuperscript{177}

\textsuperscript{171} Id.
\textsuperscript{172} Id.
\textsuperscript{173} Id.
\textsuperscript{174} Id. at 238. In so deciding, the court cited another early casinghead gas case in support of its decision. Locke v. Russell, 84 S.E. 948 (W. Va. 1915) (holding that lessee had properly accounted to the lessor for a share of the "net returns" resulting from the capture of gasoline vapors and was not liable for the flat-rate gas well rental).
\textsuperscript{175} Wemple, 83 So. at 238.
\textsuperscript{176} Id.
\textsuperscript{177} Id.
emphasized that royalty rights "must be determined, not by isolating certain words from the connection in which they occur, and putting an interpretation upon them without regard to their relative situation, but by considering all the language of which the words form a part." Unfortunately, this sound principle of construction has been ignored in several modern cases.

An oil and gas case that is conceptually similar to Wright v. Warrior Run Coal Co. is Wemple v. Producers' Oil Co., one of many early cases that dealt with casinghead gas. Under the lease, the lessor reserved an "equal one-eighth of all oil produced and saved upon said premises, to be delivered in any pipe line to which (any) well or wells may be connected, to the credit of [lessor]." For gas, the lessor was to receive $200 a year "for the product of each well." A total of ten oil wells were drilled, and the lessee constructed a plant for saving casinghead gas and a plant to extract gasoline from the casinghead gas. The lessee contended that it was entitled to save the casinghead gas without compensating the lessor for its value. Alternatively, the lessee argued that, at most, the lessor was entitled to $200 a year for the product of each well. At the time of this litigation, the particular means by which the casinghead gas was saved and processed for the extraction of gasoline was a new innovation not contemplated by the parties to the lease at the time of its execution in 1909. After noting that the lease made no mention of casinghead gas, thereby implying that the lessee had no right to the casinghead gas, the court noted that the lessor had nevertheless conceded such right to the lessee by seeking compensation for the lessee's use of the surface in connection with the gasoline plant. The court then summarized the lessee's position as follows:

\[
\text{W}hile \text{gasoline obtained from casing-head gas is oil, within the terms of the lease, in so far as [lessee's] . . . right to produce and save it 'on the premises' is concerned, it is not oil.}
\]

163. Id. (emphasis added).
164. These modern cases will be discussed in Part 2 of this essay.
165. 38 A. 491 (Pa. 1897). Wright is discussed at the beginning of this subsection, supra notes 138–46 and accompanying text.
166. 83 So. 232 (La. 1919).
167. Id. at 233.
168. Id. at 235. Casinghead gas first became commercially important in 1904, and the first compression casinghead gasoline plants were built in the mid-continent in 1909. With the development of the more advanced absorption process in 1917, the extraction of gasoline from casinghead gas became a major segment of the oil and gas industry. This segment declined some in the 1930s when improved refining methods and cracking processes diminished the demand for natural gasoline as a blending agent with refined products. SAMUEL H. GLASSMUI, LAW OF OIL AND GAS LEASES AND ROYALTIES § 63, at 229 (2d ed. 1938).
169. Wemple, 83 So. at 236.
170. Id. at 237.
Although in cases where royalty was at issue, the courts have tended to classify casinghead gas as falling under the provisions of the oil royalty clause where the lease did not expressly mention casinghead gas, the court in *Wemple* justifies its holding, in large part, on reasonable expectations grounds. That is, the lessor reasonably expects to share in the benefits derived from the sale or use of any product of a well—in this case, gasoline. Although many cases would have limited the compensation to the value of the casinghead gas by reference to a casinghead gas market, no evidence was offered in *Wemple* as to the existence of such a market. Instead, the lessee argued that it should be allowed to deduct a charge for the additional expense incurred in saving gasoline. The lessee did not argue that the saving of gasoline was a "post-production" activity. Rather, the lessee seemed to argue, in equity, that because the saving of gasoline was unanticipated at the time the lease was executed, the lessor should be charged a proportionate share of the cost of saving the gasoline by deducting such cost from the lessor’s share of the unanticipated value of the saved gasoline. In view of the small expense involved, the court declined to grant this relief.

In *Clark v. Slick Oil Co.*, a lease executed in 1911 provided that the lessee was "to deliver to the credit of the [lessor] . . . free of cost, in the pipeline to which [lessee] . . . may connect the well or wells, the equal one-eighth part of all oil produced and saved from the leased premises." The oil in question contained "cut oil"—oil, which according to the court, was contaminated with water and mud. This cut oil had to be removed before a pipeline would take the oil. Initially, the lessee made arrangements for an affiliated third party to first store all of the oil in settling tanks, and,
after the cut oil settled to the tank bottoms, to purchase all of the oil at the posted field price.\textsuperscript{185} When the oil began to sell for a premium above the posted field price,\textsuperscript{186} the lessor demanded additional royalty payments. When these demands were not met, the lessor demanded his share of oil in kind. The lessee then advised the lessor to secure settling tanks to store the oil for the settling of the cut oil prior to sale—such removal being necessary to make the oil marketable. On the question of whether the lessor had to secure settling tanks, the court commented as follows:

It was not incumbent upon the [lessor] \ldots to furnish storage tanks to receive and care for the oil. Under the contract it was the duty of the [lessee]\textsuperscript{187} \ldots to care for the oil until it was delivered in the pipe line, and there is where the [lessor] \ldots was entitled to have it delivered. It was not necessary for the [lessor] \ldots to treat his part of this oil and make it marketable so that the pipe line companies would receive it. Neither was he required to provide storage tanks in which to let the "cut oil" settle. It was just as much a part of the duty of the [lessee] \ldots under the contract to prepare this oil for market so that it would be received by the pipe line company as it was its duty to pump the oil from the wells or drill the wells. The [lessor] \ldots had a right to demand his oil delivered in the pipe line, and the [lessee’s] \ldots duty was not discharged until it was so delivered.\textsuperscript{188}

Thus, Clark is an early case construing an oil royalty clause as requiring the lessee to "treat" the lessor's oil to "make it marketable." Of course, by implication, once the oil is in a marketable condition, i.e., of sufficient

\textsuperscript{185} As to the oil for which lessor had accepted such settlement, the court held that the lessor had waived his right to have the oil delivered free of cost in the pipeline, but that the lessor was free to demand such delivery in compliance with the lease royalty clause with regard to all oil for which the lessor had not accepted settlement. \textit{Id.} at 500. Although the case does not appear to involve a formal division order, this case may be the earliest case supporting the notion that a lessor may freely revoke a division order at will.

186. This case is also an early "posted-price" case. After removal of the cut oil, the lessee sold the lessor's royalty oil to an affiliated purchaser at the posted field price; however, at that time, premiums above the posted price were commonly being paid. The court concluded that the lessee's actions constituted conversion and that the lessee should be found liable for the highest market price for the oil so converted between the date of conversion and the verdict. \textit{Id.} at 502.

187. Although the court refers here to the "plaintiff" lessor, the context of the paragraph clearly indicates that the court was intending to refer to the lessee's duty.

188. \textit{Id.} at 501 (emphasis added).
quality that it can be delivered into a pipeline, a lessor who wishes to take his oil in kind must furnish his own tankage.189

In Busbey v. Russell,190 the court determined the royalty due on gas by construing both the gas and oil royalty clauses of the lease. The oil royalty clause provided that "... one-eighth part of all the oil produced and saved was ... to be delivered to the lessor, free of expense into tanks, or into pipe lines to his credit."191 The gas royalty clause provided that, if wells produced gas in sufficient quantities to justify marketing, the lessor "should be paid at the rate of one-eighth of income dollars per year for such well so long as the gas therefrom should be sold."192 The court, finding that the lessee owed a gross-receipts, not a net-profits, royalty based on the gross receipts from the sale of the gas, stated:

It was impracticable to deliver one-eighth of the gas itself to the lessor as was to be done with the oil, and it seems reasonable that he would stipulate for the same proportion of the receipts from the marketed gas, instead of running the risk of no substantial return for the gas by reason of bad financial management and wasteful expenditures on the part of the lessees.193

Thus, the court concluded that the parties intended to treat the gas royalty provision as being consistent with the oil royalty provision, i.e., that gas royalty was due on a fraction of gross receipts, just as oil royalty was due on a fraction of gross production. This case recognizes that the proper calculation of royalty depends upon the wording of the applicable royalty clause and implicitly rejects the notion of a property law definition of the royalty obligation. And like Maloney v. Love,194 and like the next case, the Busbey court emphasizes that royalty clauses should not be construed by isolating and defining specific words, but by construing the entire royalty provision as a whole. To assist in determining the appropriate result, the Busbey court construed both the oil and gas royalty clauses, even though only gas royalty was at issue.

In Scott v. Steinberger,195 the Kansas Supreme Court determined the meaning of a gas royalty clause by reference to the oil royalty clause. The gas royalty clause provided that the lessee was "to pay [to lessor] one eighth
of all gas produced and marketed." The oil royalty clause provided that lessee would "deliver to the credit of [the lessor] . . . free of cost in the pipe lines to which he may connect wells one-eighth of all oil produced and saved on said premises" or, at lessor's option, pay lessor "the market price for same in cash." The lessee constructed its own pipeline to transport the gas to a distant town where it was sold. When remitting royalty, the lessee deducted a charge for transporting the gas through the pipeline. This charge was apparently calculated on the reasonable rental value of the pipeline. In support of its holding that the lessee could deduct a "reasonable transportation charge," the court found as follows:

Evidently, the parties [to the lease] contemplated that, if oil or gas in paying quantities was found, some pipe line company would build into the field and transport it to places of consumption. It will be observed that the provision respecting oil was that the lessors should deliver one-eighth of the oil into the pipe lines to which the wells might be connected and pay the market price in kind or in cash as the lessor should desire. In the same connection it was provided that the lessee should pay one-eighth of the gas produced and marketed. We think the parties contemplated and the provision should be construed that gas, if produced, should be measured and the price determined at the place where the wells were connected with pipe lines, and not at some distant market that might be found at the end of a pipe line remote from the field and where the cost of transportation might equal or exceed the value of the gas produced . . . . The place of measurement and for fixing the lessor's share was at the connection with the pipe line.

The sole issue in the case was the lessee's deduction for "freight." The gas was apparently in a marketable condition when it was delivered into the pipeline as the gas was simply transported from that point to the point of sale. By reference to the oil royalty clause, the court determined that both the value and quantity of gas had to be measured at the point where the gas is delivered into the pipeline because the parties did not contemplate that gas royalty valuation take place at some distant location. Scott implicitly stands for the proposition that gas is to be valued in a marketable condition in the vicinity of the well.

196. Id. at 647. "Rental value of the pipe line built by the defendants was found to be $15,000 per year, and the reasonable transportation charge for transporting gas from the field . . . was found to be 7 cents per 1,000 cubic feet."

197. Id. Because the lessor had a right to use part of the gross production of gas for domestic purposes, the court noted that the lessor's right to gas royalty was limited to gas which was both "produced and marketed."
In *Martin v. Amis*, the successor lessee produced wet gas and delivered it to a buyer who extracted gasoline and then sold the gasoline and residue gas. Pursuant to the terms of this arrangement, the buyer paid the successor lessee 1/4 of 7/8 of the proceeds received for sale of the gasoline and paid lessor 1/4 of 1/8 of such proceeds. The lease royalty clause provided as follows: "To deliver to the credit of the lessors, free of cost, in the pipeline to which lessee may connect the well or wells, the equal one-eighth part of all oil, gas, casing-head gas and gasoline, produced, manufactured and saved from the leased premises, payable monthly as same is sold."

The Texas Commission on Appeals summarily rejected the lessor's argument that the gas sales contract was in reality a service contract whereby the buyer agreed to extract gasoline on the lessee's behalf. Rather, the court held that the contract constituted an executory sale of wet gas to the buyer, who held no interest in the lease, and that an actual sale was executed when the gas was delivered to the buyer. In other words, title to the raw gas passed from the lessee to the buyer upon delivery, and the extraction of gasoline was not imputable to the lessee.

Although the court did not carefully consider whether the gas contract was really a service contract which was disguised as a sales contract for the purpose of reducing royalty obligations, *Martin* demonstrates that, in the absence of a clear expression to the contrary, royalty is ordinarily payable at the point at which the gas is first marketed, i.e., when it first becomes a marketable product. *Martin* (and the next case) further illustrate that, subject to the limits of the marketplace and the lessee's good-faith obligation to the lessor to act reasonably and prudently for their mutual benefit, lessees can establish the point at which gas first becomes a marketable product and, hence, the point where royalty is payable.

It is interesting to compare *Martin* to the earlier Oklahoma case of *Barton v. Laclede Oil & Mining Co.* In *Barton*, the Oklahoma Supreme Court construed what is apparently an oil and gas lease containing a gas royalty

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199. *Id.* at 433. Also, pursuant to the contract, the buyer accounted to the lessee and lessor on the same basis for the proceeds of sale of the residue gas. *Id.*
200. *Id.* at 431.
201. *Id.* at 433.
202. *Id.*
203. 112 P. 965 (Okla. 1910).
204. The nature of the Barton/Laclede agreement is unclear. The court calls the Barton/Laclede transaction a contract. Later, the court refers to the gas being discovered on "the said lease with [Barton]." *Id.* Thus, Barton appears to be the lessor and Laclede, the lessee; however, it is possible that Barton is a co-lessee or assignor who reserved an
clause whereby Laclede agreed to pay Barton "one-tenth portion of each and every gas well drilled on the premises herein described when utilized and sold off the premises, payable monthly as long as gas is to be so utilized." After gas was discovered, Laclede appears to have sold the gas to a third party, Bellevue Oil & Gas Company, for transport and resale. As consideration, Bellevue agreed to pay "one-half portion of the proceeds of collection arising from the use and sale of gas." In other words, Laclede apparently agreed to sell the gas in return for 1/2 of its resale price. The court held that the gas royalty clause required Laclede to pay Barton 1/10 of all gas "utilized and sold off the premises," not just 1/2 of that amount. Although the court did not explain its reasoning, it is obvious that the court believed that Barton was entitled to a full 1/10 royalty on all gas sold and that the amount payable should be determined on the basis of its downstream value. Whether the court viewed the Laclede-Bellevue contract as something other than a bona fide sale is unclear. Nevertheless, the case illustrates that lessees have significant influence over gas marketing. In this instance, the lessee’s influence did not happen to work to its advantage.

It developed into a common practice for a third party to perform specified services with respect to gas transportation, processing, and marketing in return for a share of the ultimate sales proceeds. In the earliest form of this practice, as in Barton, the third party merely provided a service in return for a share of the gas. Later, the arrangement would be tailored to reflect a sale of the gas to the third party; however, the sales price was generally determined to be a share of the resale price of the gas, liquids, or both.

overriding royalty.

205. Id.
206. This is also unclear. At one point the court says that Laclede "agreed to sell gas to . . . Bellevue." Id. At another point, due to the unfortunate use of a pronoun, it is unclear whether Laclede sold gas to Bellevue at a price based upon in 50% of the resale price, or whether Laclede agreed to pay Bellevue 50% of the ultimate sales price in return for the service of "piping and selling" the gas. Id.
207. Id.
208. Id. at 965 – 66.
209. This early decision may illustrate a partial misunderstanding of the intent of that portion of the royalty clause calling for royalty on gas "utilized and sold off the premises." Id. at 965. Often gas was not sold or used off the premises. It was often vented, flared, or occasionally used on the leased premises for lease operations. Undoubtedly, Laclede intended that royalty would be payable based upon revenues actually received for gas that was actually marketed (or payable based upon the value of gas used for other than lease operations), less any costs incurred in transporting the gas to a distant market.
210. This change was perhaps made in response to the holding in Barton.
211. Courts have not expressly addressed the question of whether this type of arrangement constitutes a bona fide sale of a marketable product or, in reality, a contract for the performance of a service to make gas marketable (or in some cases, to transport gas to
In Armstrong v. Skelly Oil Co., the Fifth Circuit construed a royalty clause which provided that the lessor was to receive "for gas produced from any oil well and used off the premises a royalty of 1/8 of the market value for said gas as such for the time during which such gas shall be so used . . . ." The lessee erected a plant to extract gasoline from wet gas produced from wells located on the lessor's land. The residue gas was then sold for the manufacture of carbon black. The market value of the wet gas was determined by periodically testing the wet gas for its gasoline content. A 1/8 royalty was paid on a percentage of the wet gas, 20% to 33 1/3%, depending on the gasoline content. Additional royalty was paid on residue gas sold on the carbon black market. The residue gas revenues were allocated 50% to the gasoline plant and 50% to the "lessee" (undoubtedly meaning "lease," in that the lessor was paid a 1/8 royalty on 50% of the residue gas). The court noted that "[t]here is an established market value of casing-head gas, and the above set out method of payment is universal in the oil fields." The court also noted that the gas would be valueless if not used for extracting gasoline and sold on the carbon black market. Later, the court noted that the gas "was not sellable except for the extraction of gasoline." The lessor argued that royalty should have been paid on all revenues derived from the sale of the gasoline and the residue gas. The court rejected this argument by concluding that the lessee was "entitled to market, or both). Obviously, under this arrangement, a third party was willing to take title to the gas, process it, perhaps transport it, and resell it for a portion of the revenues. Hence, the third party does assume part of the risk of loss of gas and loss of profits—a risk that would not ordinarily be assumed under a pure service contract. Moreover, this practice is so well established that to challenge its bona fides now would disrupt long-settled custom and practice. Nevertheless, apart from executing division orders that may have reflected this arrangement, lessors have not been a party to these contracts. It is likely, however, that some outright arm's-length-equivalent sales of wet gas to gasoline plant operators could be identified which would establish that wet gas is, in fact, a first-marketable product. See, for example, Armstrong v. Skelly Oil Co., 55 F.2d 1066 (5th Cir. 1932), discussed immediately infra.

212. 55 F.2d 1066 (5th Cir. 1932) (applying Texas law).
213. Id. at 1067.
214. Id.
215. Id. The court also noted that the royalty valuation method was the one approved by the Department of the Interior "in dealing with casinghead gas on Indian lands."
216. In a companion case, decided on the same day and rejecting lessor's argument that the lessee had violated the implied covenant to drill additional wells, the court noted that the gas in question was also sour and, due to an ample supply of sweet gas, was not marketable in the more lucrative natural gas market. The court, however, did note that the gas was marketable for the purpose of extracting gasoline and making carbon black. Armstrong, 55 F.2d 1066 (a one-page opinion with the same name and found on the same page as the principal case).
217. Id. at 1068.
218. Id.
deal with the lessor the same as a stranger would have done. Had the gas been sold to an extracting plant, the lessee, under the universal custom of the trade, would have received returns identically the same as those made by [lessee]."

In Armstrong, the court found that there was an established market for wet gas for use in extracting gasoline and for the residue gas in making carbon black. In other words, the gas was marketable as it came from the wellhead, and the lessor received royalty identical to what the lessor would have received had the lessee marketed the wet gas to a third-party gasoline plant operator. Here the lessee was engaged in a post-wellhead activity, extracting gasoline from wet gas, that is implicitly and properly treated as a "post-production" activity because there was an established market for wet gas in its natural condition at the wellhead.

These early United States cases demonstrate that "royalty" is a sharing arrangement that has no specific meaning as a matter of property law. Historically, courts have construed royalty clauses as they would any contractual undertaking. Moreover, although not always expressly articulated, the facts of these early cases show that royalty was generally paid on the value of the oil, gas, or mineral as an actual marketable product. However, as the following cases illustrate, the lessor has never been entitled to have its proportionate share of production transported cost-free to the point of sale or to receive royalty on the enhanced value of gas following its transportation to a distant market.

In Rains v. Kentucky Oil Co., the Kentucky Court of Appeals construed the following gas royalty provision: "If gas only is found, second party agrees to pay fifty or 1/8 dollars each year for the product of each well while the same is being used off the premises . . . " The lessee completed gas wells on the property and sold the gas to buyer for 6¢/Mcf. The buyer transported the gas through a pipeline to a town where the gas was resold, under franchise, for 42¢/Mcf. After concluding that this clause gave lessor the right "to receive $50 for each well, or, at his option, one-eighth of the gas," the court then considered the following issue: "Should the contract be construed as requiring the lessee to pay one-eighth of the gas at

219. Id.
220. Of course, there is more recent contrary authority, which will be discussed in Part 2.
221. 255 S.W. 121 (Ky. App. 1923). See also Scott v. Steinberger, discussed supra text accompanying notes 195–97.
222. Id. The italicized words were hand written in a blank on the form.
223. Id.
224. Id.
the wells, or one-eighth after it is delivered to Williamsburg?" The court reasoned as follows:

It is the custom to pay one-eighth of the oil in the pipeline, but there is a wide difference between the delivery of oil in the pipeline, and the delivery and marketing of gas to the individual consumers in a city. The latter is generally conducted as an independent business, and is attended by a very large expense in the obtaining of the franchise distribution of the gas. While the lessee may be under the duty of using reasonable effort to market the gas, we are not inclined to the view that this duty, in the absence of a contract to that effect, is so exacting as to require him to market the gas by obtaining a franchise from some town or city and distributing the gas to the inhabitants thereof. On the contrary, he fully complies with his duty if he sells the gas at a reasonable price at the well side to another who is willing to undergo the risk of expending a large amount of money for the purpose of distributing the gas to the ultimate consumers. We are therefore constrained to the view that under the contract in question appellant was entitled to ... one-eighth of the fair market price of the gas at the well side.

The court then affirmed a judgment for the lessor of $400.00.

Because the facts state that the lessee was able to sell the gas at the well, the gas was obviously in a marketable condition at the point of sale. Moreover, the court noted the custom of paying oil royalty "in the pipeline"—a point where the oil is free of water and base sediment and, thus, in a marketable condition. Accordingly, Rains stands for the proposition that a lessee may fulfill its duty to market "if he sells the gas at a reasonable price at the well side." In other words, the lessee does not have a duty to transport marketable gas to a distant market to obtain a higher price.

In Clear Creek Oil & Gas Co. v. Bushmiaer, the court construed a gas royalty provision providing that the basis for royalty was "the market price of royalty gas at the well ...." The lessee transported the gas for sale and distribution to end users for 10¢/Mcf, incurring transportation and distribution costs of 3.5¢/Mcf. The Arkansas Supreme Court, in reversing the Chancellor's ruling that royalty was due on the full 10¢/Mcf sales price,

225. Id.
226. Id.
227. 264 S.W. 830 (Ark. 1924).
228. Id. at 831.
concluded that the deduction of transportation costs was proper. In holding that the lessee could deduct transportation charges, the court applied the normal contracts measures of damages for breach of the duty to deliver goods: "the difference between the contract price and that of like goods or products at the time and place where they should have been delivered." The court then noted that, "if there be no market value at the place of delivery, the value of the goods or other product should be determined at the nearest place where they have a market value, deducting the extra expense of delivering them there." Note that the difference between these measures is the cost of transporting identical goods. These measures do not apply to nonconforming goods, such as goods that are not marketable, compared to goods that are marketable. These measures merely recognize that goods may have different values, depending upon their location.

One aspect of the case is confusing. At two points in its opinion, the court stated that "other producing companies" were paying "owners" of gas wells in the field 2.5c/Mcf. These statements indicate that other producers were accounting for gas at the wells (perhaps at a posted price), but there is no indication what they did with the gas. Thus, although there appears to have been wellhead purchases in the field, the court nevertheless indicates that testimony "shows that there was no market for gas at the wells."

The court concluded that the value of the lessor's gas was 6.5c, the difference between the lessee's 10c sales price and the 3.5c transportation cost. In so doing, the court rejected the lessee's argument that it should be allowed to account to the lessors on the basis of 2.5c/Mcf, the amount other producers were paying for gas in the same field. Apparently, the court concluded that there was either no market for the litigant lessee's gas in the field, as opposed to other gas in the field, because the lessee was not marketing its gas at that point, or that there was no real market at all in the field; however, there is no suggestion that the court regarded the 2.5c price paid by other producers as fraudulent. Accordingly, Clear Creek implicitly recognizes that gas produced from a common reservoir by several

229. Id. at 832. This case also sustained the lessee's practice of meeting demand by ratably producing its wells through periodic shutting in of production so "each one [well] would furnish its proportionate part of the gas used by the industrial consumers." Id.

230. Id.

231. Id. These measures of damages are also found in the Uniform Commercial Code. U.C.C. §§ 2-713(1) – (2), 2-723(2).

232. 264 S.W. at 831 – 32. At the first of these points, the court refers to this payment as "royalty." Id. at 831. Thus, "owners" must be a reference to other lessors.

233. Id. at 832

234. Id.
producers may have varying market values depending on the particular producer and on the particular manner of marketing. In addition, this case recognizes that lessees may deduct transportation costs when accounting for royalty, and it arguably stands for the proposition that the lessee must proportionately share any net benefits received by reason of downstream marketing with the lessor.

It is interesting to compare Clear Creek with Warfield Natural Gas Co. v. Allen. In Warfield, decided in 1935, the Kentucky Supreme Court construed a gas royalty clause requiring "[t]he lessee to pay for each gas well from the time and while the gas is marketed the sum of one eighth of proceeds received from the sale thereof, payable each three months." In paying royalty under this provision, the lessee calculated the royalty at 1/8 of $12x, the "the maximum price paid for gas in the field" even though it apparently sold the gas away from the field at a higher price. In construing the royalty clause, the court observed:

What These Leases Mean?

. . . . Defendant [lessee] had the exclusive right to produce the gas and to market the gas. It was as much its duty to find the market as to find the gas. Nothing is said about its expenses of doing either. It must be presumed that the payment by the defendant [lessee] of its expenses in doing both is the consideration it is to pay for its seven-eighths of the proceeds, for it pays no other and it certainly gets the lion's share.

Proceeds of sale, unless there is something in the context showing to the contrary, means total proceeds.

Where Must Market Be Found?

The lease is silent as to where this market must be found. In such case, it is usually held to be at the place of production . . . . So we can say the defendant [lessee] took this gas at the well, and the question is what must it pay for it.

235. For analogous case law, see Phillips Petroleum v. Bynum, 155 F.2d 196 (5th Cir. 1946) (holding that market price for gas sold to pipelines is not an appropriate measure of value for gas processed in gasoline extraction plants), and Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981) (holding that royalty payable on "market price" may be paid on the contract price for which the particular lessee sold the gas, rather than the spot market price of gas at the time of production).

236. 88 S.W.2d 989 (Ky. 1935).

237. Id. at 990.

238. Id.
Must it pay its value there or must it pay what it may ultimately have got for it?

The testimony of the plaintiff . . . shows gas is usually sold at the well in this locality where these wells are situated and that 12 cents per thousand feet is the usual price in that locality, and that this price and custom prevailed there when these leases were made. Then that must have been what the parties contemplated when they made this lease . . . .

. . . Nothing was said in the lease about a sale elsewhere and this lease must be held to mean one-eighth of the gross proceeds of a sale of the gas at the well side, and that is all for which defendant must account even though it may market the gas elsewhere and get a much greater sum for it.

This portion of the opinion must be considered in light of the stated facts of the case: that there was an established market value for gas in the field, i.e., 12¢, but that the lessee transported its gas to a distant market to obtain a higher price. In other words, the issue in this case concerned the fact that the value of gas had been enhanced as a result of the lessee's transportation of the gas. Warfield does not stand for the proposition that the lessee may charge the lessor, through royalty accounting, for a proportionate share of the costs necessary to make the gas marketable. It merely stands for the proposition that the lessee need not pay royalty on the value of the gas after it has been transported to distant market. And, although the facts do not reveal the downstream sales price or the cost of transportation, the lessee was apparently not obliged to share any additional profit with the lessor after deducting the costs of transportation, even though the royalty provision calls for royalty on "proceeds received." Presumably, the transportation of the gas generated more profit for the lessee; otherwise, the lessee would have sold the gas at the wellhead for 12¢. This is in contrast to Clear Creek, above, where, although the royalty was due on "the market price . . . at the well," the court appears to have awarded the lessor a share of the additional downstream profits.

Given the modern distinction that some courts make between the words "proceeds" (or "amount realized") and the words "market price" (or

239. Id. at 991–92.

240. Accord Reed v. Hackworth, 287 S.W.2d 912 (Ky. App. 1956) (royalty is not owed on sums attributable to the transportation of gas); Rains v. Kentucky Oil Co., 255 S.W. 121 (Ky. 1923).
"market value"), the holdings on the matter of downstream profits in Clear Creek Oil and Gas Co. v. Bushmiaer and Warfield Natural Gas Co. v. Allen seem counterintuitive. Under a "proceeds" lease (Warfield), one would expect that royalty would be payable on the actual gross proceeds of sale downstream less transportation costs; in other words, the lessor would share in any additional downstream profit. Yet, the Warfield court held that royalty was owed on the price other producers were actually receiving for at-the-well sales. And under a "market price . . . at the well" clause (Clear Creek), one would expect that royalty would have been payable on the actual selling price of comparable gas at the wells, not upon gross proceeds less transportation costs as the Clear Creek court held.

On the other hand, if one considers that some jurisdictions treat "proceeds" and "market price" royalty clauses the same, then the proper royalty valuation in Clear Creek and Warfield should have been the same. If royalty is generally payable on the value of gas as a first-marketable product, then royalty should have been calculated on the basis of the actual price received for comparable gas sold in the vicinity of the well. Obligating the lessee to share additional downstream profits with the lessor would only be justified on the basis of a broad implied covenant to market. Of course, if royalty is payable on the intrinsic value of gas that is not actually marketable at the wellhead, then requiring the lessee to share downstream profits is justified to protect against overreaching by the lessee, who then has a strong incentive to maximize post-wellhead deductions when calculating royalty.

242. 264 S.W. 830 (Ark. 1924).
243. 88 S.W.2d 989 (Ky. 1935).
244. This view has been espoused by Professor Pierce. See generally Pierce, supra note 2.
245. The actual price paid for gas at the wells was 2.5¢. The court, however, awarded royalty based upon a the downstream sales price (10¢) less transportation costs (3.5¢) for a royalty value of 6.5¢. Admittedly, it is uncertain whether the 2.5¢ price was a bona fide one.
247. Under a broad implied covenant to market, perhaps the rule would be that the lessee was implicitly obligated to pay royalty on the greater of the value of the gas at the well (based on comparable sales) or on the actual downstream proceeds of sale less expenses (based on a work-back analysis); however, not even the late Professor Merrill, the leading advocate of implied covenants, suggested this. See generally MAURICE H. MERRILL, COVENANTS IMPLIED IN OIL AND GAS LeASES §§ 84—89 (2d. ed. 1940).
248. See generally, Anderson, Figures Don't Lie, supra note 2; Pierce, supra note 2.
Several treatise authors support the proposition that oil and gas royalties, in the absence of express lease provisions to the contrary, should be calculated at the point where the oil or gas first become marketable. The late Professor Maurice Merrill is most often cited for this view. After arguing in his seminal treatise on implied oil and gas lease covenants that the lessee has an implied duty to market oil and gas, Professor Merrill states:

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. It is erroneous to read into the royalty clause stipulations concerning the cost of marketing and preparation which are not specifically expressed.\textsuperscript{249}

Although Professor Merrill's view has drawn criticism from some commentators,\textsuperscript{250} it is consistent with general contract law. If a party to a contract owes a particular duty of performance, such as the duty to market production, that party surely has the obligation to absorb the costs of performance in absence of an express agreement to the contrary.\textsuperscript{251}

This first-marketable product view is also supported by the late Professor Kuntz in his revered treatise on oil and gas law; however, he does not base his view on the implied covenant to market. Rather, Professor Kuntz argues that the duty to secure a marketable product is part of the lessee's burden of bearing all costs of "production." Professor Kuntz does not even discuss his view in the portion of his treatise dealing with the implied covenant to market. Instead, he addresses the lessee's duty to

\textsuperscript{249} MERRILL, supra note 247, § 85.
\textsuperscript{250} Altman & Lindberg, supra note 2; Williams et al., supra note 2, at 12-16 to 12-25.
\textsuperscript{251} This principle is so fundamental that contracts scholars only discuss it in the context of whether unforeseen costs may excuse performance under the doctrines of impossibility and impracticability. There is never a suggestion that the other party to the contract is charged with costs. For example, Professor Farnsworth notes that "courts have only occasionally held that a duty is discharged on the ground of mere increase in the expense of performing it. They have generally concluded that the additional expense, even if traceable to an identifiable supervening event, does not rise to the level of impracticability." E. ALLAN FARNsworth, CONTrACTS § 9.6 (2d ed. 1990); see also 18 WALTER H.E. JAEGEr, WILLISTON ON CONTRACTS § 1963 (3d ed. 1978) ("The fact that by supervening circumstances, performance of a promise is made more difficult and expensive . . . will not excuse the promisor."); ARTHUR LINTON CORBIN, CORBIN ON CONTRACTS § 1333 (1962) ("A supervening discovery of facts that make the promised performance more difficult or expensive . . ., if they are such as are commonly foreseeable and in contemplation, has almost always been held not to discharge the contractor from his duty.").
produce a first-marketable product in a chapter dealing with the gas royalty clause, where he states: 252

... [T]here is a distinction between acts which constitute production and acts which constitute processing or refining of the substance extracted by production. Unquestionably, under most leases, the lessee must bear all costs of production. There is, however, no reason to impose on the lessee the costs of refining or processing the product, unless an intention 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. After a marketable product has been obtained, then further costs in improving or transporting such product should be shared by the lessor and the lessee if royalty gas is delivered in kind, or such costs should be taken into account in determining market value if royalty is paid in money.

It is not always easy to determine, however, when the first marketable product has been obtained. Marketability of the product may be affected because the quality of the raw gas is impaired by the presence of impurities. In this instance, it should be necessary to determine if there is a commercial market for the raw gas. If there is a commercial product, then a marketable product has been produced and further processing to improve the product should be treated as refining to increase the value of the marketable product. If there is no commercial market for the raw gas, the lessee's responsibilities theoretically have not ended, and the lessee should bear the costs of making the gas marketable. 253

Professor Richard Hemingway recognizes case law in support of both a wellhead valuation and a marketable-product valuation; however, he describes the latter as the “better approach”:

[T]he lessee is not exclusively chargeable with the costs of transportation of the products to a distant market. This appears to be true whether or not the formula for computation relates to the mouth of the well or at the ultimate point of sale . . . .

However, what of the costs of preparation of the products for market that did not involve large capital

252. 3 KUNTZ, supra note 6, § 40.
253. Id. § 40.5(b) (1989) (emphasis added). Kuntz does acknowledge that case decisions "are not all consistent with this analysis." Id.
expenditures, such as the cost of dehydration, compression, and otherwise preparing the product for market? ... [A]n analysis on the basis of the nature of the cost or the place of sale is unsatisfactory.

The better approach would seem to be whether such costs are conceived to be within the implied obligation of the lessee to market the products from the lease. Those cases would charge all such costs to the lessee that they find are within such an obligation. On the other hand, the contrary result is justified upon the counter-argument that where the lessee has, by such acts or treatment, given or enhanced the value of the product the lessor should not share in the enhanced value without sharing part of the costs.254

254. R. HEMINGWAY, THE LAW OF OIL AND GAS § 7.4 (3d ed. 1991) (emphasis added). The late Professor Victor Kulp supports the first-marketable-product view as follows:

Sometimes the product must be treated before it is marketable. No part of the expense of doing so is chargeable to the lessor in the absence of a special provision in the lease, although present-day leases divide the expense proportionately to the interest.

VICTOR H. KULP, OIL AND GAS RIGHTS § 10.71 (1954). Kulp does not explain how "present-day leases" divide marketing expenses.

Messers Lawrence Mills and J. C. Willingham address the lessee's duty to market as follows:

The ordinary commercial oil and gas lease, however, provides that the lessee shall deliver, to the credit of the lessor, free of cost, into the pipe line to which he shall connect his wells the equal of one-eighth of all the oil produced and saved from the premises. Gas royalties sometimes follow the same form . . . .

LESSEE'S DUTY TO PUT PRODUCT IN MARKETABLE SHAPE

This covenant is held to carry with it a duty to treat the oil or gas and put it in marketable condition for delivery to the pipe line. Otherwise stated, it frequently happens that under great pressure the oil becomes mixed with water or other foreign substance which must be removed in order to make it marketable. It is the duty of the lessee, without expense to the lessor, to treat the oil and remove the water and "B.S." (Basic sediment), so that the pipe line will purchase . . . .

Just how far the doctrine of duty to treat is applicable is an undecided question. Reasoning from the analogy of the duty to drill additional wells it would seem that the lessee could not be required to undertake an entirely unprofitable transaction . . . .

If, on the other hand, the lessee covenants to deliver in tanks at the well or into the pipe line, there is room for argument as to the construction. If he (the lessee) may elect which he will do then he would seem to satisfy his obligation by putting the royalty oil in a tank without treating. If that be
Regarding the oil royalty clause, A.W. Walker, perhaps the Dean of Texas oil and gas law, has stated:

correct, then he would, in such a case, be entitled to charge lessor his proportion of the expense of treatment.

These questions come up from time to time when a well produces some off-color product unsuitable for market through ordinary channels. Cut oil is one, liquid asphalt another . . . . Where unusual expense is required, and the contract does not cover the case, if the lessee undertakes to treat his own, it would seem to be his duty to also handle the royalty with a right to reimbursement for a proportionate share of expense . . . .

Oil may be produced at a point remote from a pipe line. By reason of difference in gravity it may not be acceptable to a pipe line otherwise available. Gas may be found at a distance from a gas line; or the pressure may be so low in proportion to that maintained in the line that it cannot be delivered into the line without the erection of a booster station . . . .

Is the lessee bound to market? If so, at whose expense? The implied duty to operate is said to include the duty to market. But this is a matter of reasonable diligence and does not touch the question of expense. It seems reasonable to assume that the lessee is not bound to market at a loss. Nor does it seem reasonable to assume that he is bound to construct a pipe line for many miles or undertake other large outlays of expense merely because a profit can be figured on paper. If there is danger of drainage, he is in duty bound to protect the lines by drilling offset wells, providing it can be done at a profit. So, by analogy, if marketing is necessary to prevent drainage, he is bound to market if it can be done at a profit. Ordinarily in such case the expense would not be excessive. There might, however, be cases of actual or probable drainage where the expense of marketing would be excessive and might or might not be handled at a profit . . . .

It has been held, however, that the lessor is entitled only to his oil or gas or the value thereof at the well and not at some distant market. So, if the lessee constructs a pipe line or deals with another to do so, he is entitled to charge against the lessor his proportion of the reasonable rental value of such line. The lessor, however, is not liable for the cost of such line.

Where the lessee undertakes to and does market his own oil or gas by pipe line or tank car, it would seem that he would be bound to take the royalty share along with his own, but is only liable for the reasonable value of the royalty share at the well.

L. MILLS & J.C. WILLINGHAM, THE LAW OF OIL AND GAS §§ 126, 129, 130 (1926). This excerpt recognizes a duty to market free of expense to the lessor if the expenses are not excessive. This duty does not include a duty to transport, nor does it include a duty to market a product at a loss. Since no court has ever held that a lessor must proportionately bear expenses incurred in preventing drainage, the authors' analogy to the implied covenant to protect against drainage suggests that the lessee would be required to bear all reasonable expenses necessarily incurred to obtain a first-marketable product if the resulting product could be marketed at a profit.
Some leases provide that the royalty oil may be delivered in the pipe line to which the wells are connected, "or at wells," or "into storage tanks." It would seem, under this clause, that the lessee's obligations are at an end when he has made a delivery at the place designated, and that the expense of storage and transportation thenceforth must be borne by the lessor. A plausible argument may be made, however, that the expense of treatment incident to putting the oil into a marketable condition would rest, nevertheless, upon the lessee, if the lease contains the customary provision for a royalty of a fractional part of all oil "produced and saved," on the theory that the amount of oil "saved" is the amount remaining after treatment and that the lease contemplated a royalty division only after treatment by the lessee.\(^\text{255}\)

The late A.J. Thuss comments as follows:

If the royalty is payable in money . . . the lessor is dependent upon the diligence and good faith of the lessee. When the lease is silent as to the duty of the lessee, the law imposes a duty upon him to exercise ordinary or reasonable care in marketing the product. If the contract is silent as to the place to market the production, then one having control must exercise good faith and diligence to market at such place as will obtain the best price.\(^\text{256}\)

Although Thuss recognizes that the lessee has a duty to market, he does not state whether the lessee must absorb the marketing expenses. Surely, however, had he believed that marketing expenses should be shared by the lessor, he would have so stated. Again, under basic contract law, in the absence of an agreement to the contrary, where a party to a contract owes a duty of performance, that party must also bear the cost of that performance.\(^\text{257}\)

\(^{255}\) A.W. Walker, Jr., The Nature of the Property Interests Created by an Oil and Gas Lease in Texas, 10 Tex. L. Rev. 291, 313 (1932).

\(^{256}\) A.J. Thuss, Jr., Texas Oil and Gas § 126 (2d ed. 1935).

\(^{257}\) See supra note 251.

Several scholars, with only limited citation to pertinent authority, summarize what they believe to be the governing law on royalty valuation without stating whether they agree with that law. For example, Professor Howard Williams states:

A royalty or other nonoperating interest in production is usually subject to a proportionate share of the costs incurred subsequent to production where, as is usually the case, the royalty and nonoperating interest is payable 'at the well'.

3 Howard R. Williams, Oil and Gas Law § 645.2 (1995). And in a terms manual, Professor
Royalty valuation

Williams and his co-author, the late Professor Charles Meyers, offer various definitions of the term 'royalty,' including:

Although royalty is not subject to the costs of production, usually it is subject to costs incurred after production, e.g., production or gathering taxes, costs of treatment of the product to render it marketable, costs of transportation to market.


Professor Robert Sullivan recognizes the marketable-product view in his summary of the law regarding the lessee's implied covenant to market oil.

The lessee is subject to an implied covenant to market the oil and gas that is produced from the leased premises in order that the lessor may receive his royalty thereon. If the oil is not merchantable, the lessee must prepare it for market, and the lessor is not liable for his proportionate share of the cost in the absence of an appropriate provision in the lease . . . . Transportation to a distant point where there is no market in the field is not within the purview of this implied covenant, and the lessor must bear the cost of transporting his royalty share of production.

Robert Sullivan, Handbook of Oil and Gas Law § 92 (1955) (emphasis added). Regarding gas, however, Professor Sullivan's summary is less clear:

. . . The lease provides for payment of the royalty at the market price, market value, or proceeds at the mouth of the well. Therefore, if the gas must be transported, the lessor must bear his proportionate share of the cost of marketing. It is the price that is actually paid by buyers for the same commodity in the same market, i.e., for the same purpose.

Id. § 70. To this point, Professor Sullivan's view seems similar to Professor Merrill's view. Professor Sullivan explicitly recognizes that it is the lessee's duty to make oil merchantable without expense to the lessor, and regarding gas, transportation is the only expense specifically mentioned as a marketing cost to be shared by the lessor. Moreover, he suggests that royalty is to be payable on a "price that is actually paid by buyers for the same commodity in the same market." This language suggests that royalty is to be calculated on gas that is in a marketable condition. Following this statement, however, he then states:

It is not necessarily the same as "market value" or "fair market value" or "reasonable worth." Where the market price cannot be established because there are no comparable sales, the actual or intrinsic value can be shown. Where there is no market price at the wells, the jury is permitted to consider every factor that relates to the market value at the well. Where the lessee sells the gas on a long term contract at a fixed price, it is advisable to secure the consent of the lessor.

Id. This latter excerpt suggests that gas royalty may be computed by determining its wellhead value without regard to its actual marketability at that point. Because he supports the above statements with citations to cases, Professor Sullivan was most likely summarizing the various views reflected in case law without offering his own opinion on what the general rule should be.

Likewise, the late Professor W. L. Summers reports:

Most courts hold that the lessor's royalty should be computed upon the basis
IV. CONCLUSION

Thus far, I have established that a primary cause of the current wave of both oil and gas royalty litigation is depletion “reform.” Although, in the past, lessees may have had an incentive to overvalue production to take advantage of percentage depletion, today lessees have an incentive to undervalue production to limit their royalty (and production tax) obligations. Accordingly, courts should carefully scrutinize lessees’ choice of the royalty-valuation point and their calculation of post-production costs.

I have also illustrated that, throughout history, royalty provisions have been construed in accordance with their express language and not in accordance with some inherent property-based definition of royalty. Moreover, historically at least, courts have tended to construe royalty provisions in light of the parties’ reasonable expectations, in contrast to a strict and narrow construction of the pre-printed anticipatory language of the parties. Finally, there is early case authority and scholarly commentary in support of the view that royalty is generally payable at the point where a first-marketable product is obtained.

In Part 2 of this essay, I will discuss more modern royalty cases that wrongly determine marketability (and hence market price or value) as a matter of law, either at the wellhead or at other points downstream. I will also briefly consider the economics of royalty and offer my conclusions regarding royalty valuation.

of the market value of the gas in the field, if such market value actually exists, and if it does not, upon the basis of the reasonable value of such gas as established by competent evidence.