NATURAL RESOURCES JOURNAL

Volume 37
Issue 3 *Summer 1997*

Summer 1997

Clear as Crude: Defending Oil and Gas Royalty Litigation

William F. Carr

Paul R. Owen

WILLIAM F. CARR, ESQ.*
PAUL R. OWEN, ESQ.**

Clear As Crude: Defending Oil and Gas Royalty Litigation

A new wave of litigation in New Mexico's state and federal courts has been spawned by recent changes in the way oil and natural gas are marketed and changes in the law governing the relationship between the operators of producing properties and their royalty interest owners. This paper examines the causes of this litigation, provides an overview of relevant New Mexico law as it relates to these disputes, and reviews some practical strategies and obstacles to defending a case of this nature. While the overview presented necessarily includes background discussion of the origin and nature of current royalty disputes, for a comprehensive review of the relevant case law on the subject, readers are referred to other papers published concurrently with this writing.[1]

A royalty interest is a "share of production free of the costs of production."[2] This is a sharing arrangement created by a lease contract between the owner of oil and gas or other minerals (the lessor) and one who is given the right to go onto the lands of the lessor and explore for and develop these minerals (the lessee).[3] In return for allowing the lessor to develop the minerals, the lessee is given a share of any minerals produced, or a royalty. The share of the produced oil and gas is returned to the lessor free of the costs of production, and the appellation "royalty" can be traced to the share of mined gold or silver that was due the crown under English common law.[4]

Unlike the English king, owners of hydrocarbon royalties generally do not want and cannot practically take or use a share of the mineral produced. Instead, they want a share of the proceeds received for the

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* William F. Carr is a Santa Fe attorney practicing in Oil and Gas litigation, Administrative law and Legislation.

** Paul R. Owen is a Santa Fe attorney practicing in Oil and Gas Law and Administrative Law.

1. *See, e.g.* John S. Lowe, *Current Issues in Royalty Clause Construction*, 37 NAT. RESOURCES J. No. 3 (1997); Owen L. Anderson, *The Gas Royalty Obligation: Is Royalty Ordinarily Payable on "Raw" Gas at the Mouth of the Well or on Marketable Gas?*, 37 NAT. RESOURCES J. No. 3 (1997); Jacqueline Weaver, *When Express Clauses Bar Implied Covenants, Particularly to Market Gas*, 37 NAT. RESOURCES J. No. 2 (1997).

2. HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS TERMS at 511 (4th ed. 1976).

3. HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 301, at 437 (Supp. 1986).

4. Robert E. Sullivan, *All About Royalties*, 16 ROCKY MTN. MIN. L. INST. 227, 228-32 (1971).

product when it is sold. Although some royalties are paid in kind, most royalty is in the form of a payment based on the value of the resource.

There is nothing new about disputes between producers and royalty owners over how their royalties are calculated and paid. These matters have been litigated since the turn of the century.[5] Likewise, the issues presented by today's royalty calculation are not new and typically fall into three general categories. They involve:

> 1) The basis for calculating the royalty payment or the method of determining the value of the produced mineral (i.e., should royalty be based on the proceeds of sale of the resource, the value of the product, etc.);
> 2) The point of valuation of the product (i.e., where is the value determined on the premises, at the well, etc.); and
> 3) The quality or condition of the product (i.e., in its raw state at the mouth of the well or if not marketable at the well, after placed in a marketable condition).

Each of these issues is currently being litigated in state or federal court in New Mexico.

CAUSES OF CURRENT LITIGATION

Historically, producers sold natural gas at or near the well to a pipeline purchaser under a long-term gas purchase agreement with stable pricing provisions. However, changes occurred in the early 1980s regarding the way oil and natural gas are produced and marketed as the result of Federal Energy Regulatory Commission (FERC) orders.[6] With these changes, the pipeline purchaser disappeared. The current regulatory framework prohibits producers from selling their production to a purchaser which itself owns, processes, transports, and resells that production.

The oil and gas industry responded to these changes with new arrangements for the sale of production by forming affiliated marketing companies and using other buy/sell and exchange arrangements. Instead of basing royalty calculations on the actual value received for the specific product attributable to the particular well and, correspondingly, to the particular royalty owner, some producers calculate royalties based on a

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5. *See* Brewster v. Lanyon Zinc Co., 140 F. 801 (8th Cir. 1905).

6. *See*, for example, Order No. 436, Regulations of Natural Gas Pipelines after Partial Wellhead Decontrol, F.E.R.C. Stats. & Regs. [Regs. Preambles, 1982-85] & 30,665 (1985); Order No. 436-A, F.E.R.C. Stats. & Regs. [Regs. Preambles, 1982-85] & 30,675 (1986). For comprehensive discussion, *see* Marla J. Williams, et al., *Determining the Lessor's Royalty Share of Post-Production Costs: Is the Implied Covenant to Market the Appropriate Analytical Framework?*, 41 ROCKY MTN. MIN. LAW INST., § 12.05[4], at 12-31 (1995).

price tied to an index.[7] With sales to affiliated companies, arms length transactions became less frequent and questions were raised about the proper method of valuing production for royalty calculations.

Recent case law has changed the method of calculating royalty. Traditionally, producers have paid royalty based on the value of production at the well or some other point of valuation set by the lease. Different leases specified that royalties were to be based on the value of the production, or the proceeds of sale. If production was not marketable at the well or other point of valuation until the product had been dehydrated, compressed or treated, the costs of these activities were subtracted from the downstream sales price to mathematically compute a value upon which royalty calculations would be based. These costs, incurred after the point of valuation, increase the value of the production. Deducting the costs of these value-enhancing measures from the sales price results in the sharing of these costs between the lessor and the lessee.

Beginning in 1993, courts in several producing states have adopted the "Marketable Condition Rule."[8] These courts take the position that the implied covenant to market in oil and gas leases requires the lessee or operator to put oil and gas in marketable condition at no expense to the lessor or royalty interest owner.[9]

This rule has broad implications on existing contracts that govern the rights of owners in oil and gas interests. The rule extends the definition of "production" from the well where the product is in an unprocessed state to the point where a marketable product is obtained that could be far downstream from the well or other point of valuation set by the lease. Accordingly, under the Marketable Condition Rule, additional costs are imposed on the lessee or operator by prohibiting it from sharing the costs of postproduction value adding activities with its lessor.

With the advent of new marketing arrangements and the Marketable Condition Rule, the contractual relationships between producers and royalty owners that were stable for many years have

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7. *See* Craig R. Carber, *Natural Gas Price Indices: Do They Provide a Sound Basis For Sales and Royalty Payments?* 42 ROCKY MTN. MIN. LAW INST. § 10.03, at 10-8 et. seq. (1996). The term "index price" refers to the arrangement by which the pricing of natural gas production is tied to published indices. *Id.* at § 10.04[1][a]. The equivalent term for oil sales is "posted price," which "is a publicly announced price at which a purchaser is willing to buy a certain type and amount of petroleum products." Phillips Petroleum Co. v. Johnson, 22 F.3d 616, 621 n.4 (5th Cir. 1994).

8. *See, e.g.*, Sternberger v. Marathon Oil Co., 894 P.2d 788 (Kan. 1995); Garman v. Conoco, Inc., 886 P.2d 652 (Colo. 1994); TXO Production Corp. v. State ex. rel. Commissioners of Land Office, 903 P.2d 259 (Okla. 1994); and Wood v. TXO Production Corp., 854 P.2d 880 (Okla. 1992).

9. *See Wood*, 854 P.2d at 882-83.

increasingly become the subject of litigation. Once crystalline duties and financial arrangements have become clear as crude.

THE ROYALTY CASE—COMMON CHARACTERISTICS

Cases involving claims for improper calculation of royalty generally involve large damage claims. They are either brought by the owners of large royalty interests, by a voluntarily formed group of royalty owners,[10] or are formed in the process of litigation.[11]

Where operators make royalty payments to numerous individuals pursuant to allegedly similar royalty clauses, class action certification is often the first issue in a royalty suit and plaintiffs argue that the tests for class certification is easily met.[12] The plaintiffs will seek to characterize the lease forms used by the operator in acquiring interests in a geographic area as identical or substantially similar, in an effort to satisfy the numerosity, common questions (commonality), and typicality tests.[13] Furthermore, in an effort to meet the commonality test, plaintiffs will seek to characterize the operator's communications with its royalty owners as accomplished through identical letters or through similar oral representations at the time they executed their leases.[14] Plaintiffs also characterize as uniform the methods used to calculate and pay royalty.[15] In class action cases, the court has broad discretion and the plaintiffs will work vigorously to convince the court of superiority of a class action over numerous individual law suits. To avoid class certification, the defendant operator must show that differences

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10. *See*, for example, Complaint, paragraphs 1 and 5, Creson v. Amoco Production Co. (No. CV 91-00042) (N.M. 10th Judicial Dist. 1996), in which the plaintiffs are trustees of the Public Lands Royalty Trust which was created for the purpose of acquiring royalty interests in State of New Mexico, Federal, and fee oil and gas leases.

11. *See*, for example, Stoute v. Wagner & Brown, 637 So.2d 1199 (La. Ct. App.), *writ denied*, 644 So.2d 638 (La. 1994) (royalty owners in single field in Louisiana sought class certification in a royalty underpayment litigation case).

12. *See* Fed. R. Civ. P. 23(a) (prerequisites to certification of a class are numerosity, common questions of law or fact, typicality of class representatives' claims, and fairness and accurateness of representative parties' representation of class). *See also* SCRA 1986, 1-023 (similar requirements for class action in New Mexico State District Court).

13. *See* Mobile Mineral Corp. v. Medford Mosley, No. CV-95-1564-FDM (Ala., Mobile County, June 28, 1996) (plaintiffs sought to characterize as insignificant myriad lease clauses and other contractual arrangements, relying instead on argument that payment basis was identical for all defendants).

14. *See* Findings of Fact and Conclusions of Law on Plaintiffs' Motion for Class Certification, Feerer v. Amoco Production Co., (Civ. No. 95-0012) (D.N.M. June 25, 1996) at 5.

15. *See* Mobile Mineral, *supra* note 14 at 7.

among the prospective class members will overwhelm the proceedings and that individual questions will control and overshadow the litigation.[16]

Recently, plaintiffs have characterized the underlying leases and other agreements as standard or identical forms, despite the diverse circumstances in which each lease was developed and executed.[17] In a class certification context, this characterization can give substantial advantage to some knowledgeable royalty owners. If the court finds that the class should be certified in part because the underlying leases and other agreements are substantially similar in form or substance, the court will, in interpreting these agreements, apply an objective standard and consider the reasonable expectation of the average member of the class. Following class certification, sophisticated royalty owners with specialized knowledge of oil and gas transactions will be treated like those who have no knowledge of these transactions at all.[18] Accordingly, class certification not only increases the size of the suit, it also makes the defense much more difficult.

Where royalty owners are unable to obtain class certification, they may file numerous identical suits in the same court. The benefit to the plaintiffs of these "cookie cutter" suits is often to afford the plaintiffs most of the benefits of class certification while forcing the defendants to defend against diverse, frequently conflicting claims in the context of a series of cases consolidated for discovery or trial purposes. The benefit to the defendants is to avoid the potential of a massive judgment in a context in which many of the plaintiffs in fact have diverse interests, and may not be able to recover on the merits of their particular case.

The battle for class certification is often heated and potentially more important than the merits of the plaintiffs' claims. Consequently, pre-class certification discovery can be as involved as that for the merits portion of the case, and the strategic and practical decisions facing the practitioner are not to be taken lightly. The most common approach is to partition the case between class certification and merits issues and pursue discovery and legal briefing of each separately.

ANALYSIS OF THE CASE

Royalty suits are essentially large document contract cases. Accordingly, the first part of the case analysis involves the identification of

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16. *See* Amoco Prod. Co. v. Hardy, 628 S.W.2d 813, 817 (Tex. 1981) ("A class action . . . involving three different fields, different units and various non-unitized leases is unprecedented and virtually unmanageable.")

17. *See* Mobile Mineral, *supra* note 14 at 7.

18. Standard agreements ". . . are interpreted wherever reasonable as treating alike all those similarly situated, without regard to their knowledge or understanding of the standard terms of the writing." Restatement (2d) Contracts § 211 (2) (1982).

the documents that form the contract. In the typical suit, numerous documents will be involved and the significance of the documents in the context of the suit will depend on where they fit in the evidentiary standards announced by the New Mexico Supreme Court in the recent line of cases starting with *C.R. Anthony Co. v. Lorretto Mall Partners.*[19] In *C. R. Anthony*, the New Mexico Supreme Court defined the limits of the evidence that a court may consider in determining if ambiguity exists in an existing document which was fairly and impartially negotiated between the parties.[20] As a result of these cases, a review of the royalty obligations of the lessee operator to its royalty owner steps outside the four corners of the lease agreement and a wide variety of documents and other matters must be identified and then analyzed.

Although much more than the lease is involved, the principal document in a royalty case is the lease agreement. It is the basic contract of the oil and gas industry and all rights between the lessor and the lessee flow from this contract between them. Even though the primary consideration to the lessor under a lease is royalty, little language on royalty appears in most leases.[21] Leases take many different forms, but typically they address certain standard matters. Most lease royalty provisions set the point of

19. 112 N.M. 504, 817 P.2d 238 (1991).

20. In *C.R. Anthony*, the New Mexico Supreme Court ruled that extrinsic evidence may be considered in determining whether an ambiguity exists in the terms of a contract and that courts may look at the circumstances surrounding the transaction to determine if the chosen terms are clear. Under *C.R. Anthony*, the court may consider the contract language, the circumstances surrounding the making of the contract, the purpose of the contract, the relevant usage of the trade, the course of dealing between the parties, and the course of performance. *C.R. Anthony*, 112 N.M. at 508-09, 817 P.2d at 242-43. Whether an ambiguity exists is a question of law to be decided as a preliminary matter by the court. Mark V, Inc. v. Melekas, 114 N.M. 778, 781, 845 P.2d 1232, 1235 (1993). Only after contract language is determined to be ambiguous may the court look at extrinsic evidence of the parties' intent to aid in interpreting the terms of the agreement. Ruggles v. Ruggles, 114 N.M. 63, 860 P.2d 182 (1993). The court also has placed limits on the extrinsic evidence that may be considered to assure that only matters that could form the basis of mutual assent are considered in interpreting an agreement. Temporal constraints limit the review to evidence of the parties' intent at the time the provisions were agreed to. Antecedent events may not be considered except with course of performance and, although objective manifestations of intent may be considered, if a party failed to communicate its understanding of the agreement, its subjective intentions may not be considered.

21. Although the lease may say little about the calculation and payment of royalty, there are a number of implied covenants which apply to all lessor lessee relationships. Reasons advanced for implied covenants are that they cover matters that are so clearly within the intent of the parties that there is no need to express them, that the nature of this lessor/lessee relationship is such that it is impossible to address all contingencies in the written contract, and that they protect the lessor since the lease agreement is typically written by the lessee and offered to the lessor on a take it or leave it basis. Continental Potash v. Freeport-McMoran, 115 N.M. 690, 694, 858 P.2d 66, 80 (1993).

valuation ("on the premises," "at the well" etc.)[22] and virtually all provide for the method of determining the value of the production ("market value," "proceeds," etc.). However, few of these clauses address the marketing of production. Certain lease royalty clauses have accepted and well understood meanings in the oil and gas industry,[23] but in royalty litigation even the best term will be challenged as ambiguous. Nonetheless, if the court determines that the meaning of these terms is clear, this clause can conclusively establish the intent of the parties.

If the court determines that the royalty payment provisions in the lease are ambiguous, numerous documents must be reviewed in the context of the C. R. *Anthony* line of cases.

Some of these documents include:

> 1) Assignments. If a lease has been assigned, the assignment must be examined to determine if the assignment creates additional overriding royalty interests and if it specifies how the royalty payments to these new interests are to be calculated. The assignment may limit deductions upon commitment to a communitization agreement if there is no pooling clause in the original lease. The assignment may also attempt to tie the payment of royalty on production from the leased interest to the price paid to other interest owners.[24]
> 2) Unit Agreements. If the lease has been committed to a unit plan, the unit agreement must be examined to determine if the conformation clause has modified the royalty clause in the underlying leases.[25]

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22. If the lease is silent on the point of valuation, "at the well" is generally recognized as the valuation point. Michael P. Irvin, *The Implied Covenant to Market in the Deregulated Natural Gas Industry*, 42 ROCKY MTN. MINERAL LAW INST. 18-1, 18-24 (1996).

23. One royalty payment term with a widely accepted meaning in the oil and gas industry is "net proceeds at the well." The method of valuation is established by the word "proceeds." "At the well" sets the point of valuation and the use of the word "net" is understood to mean that if the sale of the production is not at the well, deductions must be made to the downstream sales price to mathematically reconstruct a wellhead value for the product. *See* Martin v. Glass, 571 F.Supp. 1406, 1411-13 (N.D. Tex. 1983), *aff'd w/o op.*, 736 F.2d 1424 (5th Cir. 1984).

24. In *Creson v. Amoco Production Co.*, No. CV 91-00042 (N.M. 10th Judicial Dist. 1996), certain assignments tied royalty payments to the royalty paid to the State of New Mexico or the federal government, whichever was higher. *See* Defendants' Joint Trial Brief, Creson, at 4.

25. Note that the Bravo Dome Carbon Dioxide Unit Agreement (Article 6) provides for payment of royalty on unitized substances on net proceeds at the well. *See* Defendants' Joint Trial Brief, Creson, at 8. The Unit Agreement contains standard conformation clauses that conform underlying leases to the terms of the unit agreement. *Id.* at 1.

> 3) Division Orders. These contracts may pose special problems and the law of the jurisdiction should be checked to determine if the Division Order modifies or replaces the terms of the lease or unit agreement concerning the duty to account for and pay royalty.[26]

In addition to these documents, all communications between the lessee and lessor should be evaluated in the context of the *C. R. Anthony* standard. This includes all correspondence, all printed material, if any, and all statements made in public meetings or to regulatory agencies and all testimony presented in regulatory hearings that relate to the leased interests. This review should also consider the time the lessor was allowed to review the proposed lease or other documents, the knowledge of the lessor (unless there has been a class certification), and the type of expert advice, if any, the lessor received prior to the execution of the lease. If course of performance of the parties is an issue, efforts to unitize may be important as well as the efforts undertaken by the lessee operator to market the production.

NEW MEXICO LAW

In addition to the *C. R. Anthony* standards, the documents and other facts must be reviewed in the context of the substantive law of the applicable jurisdiction. Although under review by cases currently in court, New Mexico has not adopted the "Marketable Condition Rule." Furthermore, no New Mexico case has imposed the requirement that the lessee of state or fee lands bear all the costs of obtaining a marketable product.

1. Federal Leases

The character of the land at issue will initially determine the obligations of the operator. If a federal lease is involved, the lessee is required to put the product in a marketable condition, for long ago the federal government adopted its own version of the "Marketable Condition Rule." The courts have upheld this requirement and held that leases of federal lands are subject to ongoing statutory and regulatory standards which include the Mineral Leasing Act, the Department of the Interior Regulations, lease terms and the Secretary's interpretation thereof.[27]

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26. There is no case law in New Mexico addressing the effect of a Division Order on the underlying lease obligations.

27. *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961).

2. State Leases

The State of New Mexico utilizes a statutory lease form which permits the deduction of post wellhead costs in calculating royalty.[28] In an effort to clarify and expand the State's royalty claim, the Commissioner of Public Lands adopted New Mexico State Land Office Rule 1.059 entitled "Calculating and Remitting Oil and Gas Royalties" effective January 1, 1990. The stated purpose of this amendment to the State Land Office Rules was to standardize the practice of calculating royalties under the State Oil and Gas Lease and to combat widespread under-reporting of royalties by lessees.[29]

The value of oil and gas for the calculation of state royalty is based on the "proceeds" received from the sale of the production.[30] Rule 1.059 attempted to expand the meaning of "proceeds" to require lessees of state minerals to bear the costs of obtaining marketable production with the following new definition:

> "Proceeds" means the total consideration accruing to the lessee. It includes reimbursement for dehydration, compression, measurement, or field gathering to the extent that the lessee is obligated to perform them at no cost to the lessee.[31]

Although this definition may fail to clarify what was meant by the term "proceeds," there can be no doubt that this was an attempt by the Commissioner to adopt its own form of "Marketable Condition Rule" for State of New Mexico leases.

New Mexico oil and gas producers challenged these new rules and specifically the definition of the term proceeds in court.[32] On October 16, 1996, the Tenth Circuit set aside this definition observing that while the Commissioner may promulgate rules consistent with legislative enactments, with the definition of "proceeds" in Rule 1.059 the Commissioner "creates new categories of payments not already in State Leases . . . (such as) reimbursement for dehydration, compression and measurement of field gathering."[33] The court agreed with the producer defendants that New

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28. NMSA 1978, §§ 19-10-1 et. seq. (Repl. Pamp. 1994). Not only does the state statutory lease form allow deductions of post wellhead costs in computing royalty, in the past, operators were able to meet with the Land Commissioners staff and negotiate how royalty would be calculated and paid on an individual project basis. The resulting method of calculating royalty did not even have to be consistent with how state taxes were calculated.

29. Harvey E. Yates Co. v. Powell, 98 F.3d1222, 1228(10th Cir. 1996).

30. *See*, for example, NMSA 1978, § 19-10-4.1(1) (Repl. Pamp. 1994).

31. New Mexico Land Office Rule 1.059.

32. Harvey E. Yates Co., 98 F.3d 1222.

33. *Id.* at 1239.

Mexico State Land Office Rule 1.059 "attaches new and different obligations upon lessees under the New Mexico statutory lease" and concluded that the Commissioner usurped a legislative function.[34]

3. Case law

A minority of producing states have adopted the Marketable Condition Rule. Texas[35] and Louisiana,[36] however, have rejected the theory that the Implied Duty to Market requires producers to bear all costs associated with obtaining a marketable product.[37] Although there is limited case law in New Mexico on this issue, New Mexico has historically followed Texas law on issues relating to oil and gas matters.

The New Mexico courts have held that the duty of the lessee to its lessor is that of a reasonably prudent operator, in cases such as *Watson Truck & Supply v. Males*;[38] *Continental Potash v. Freeport-McMoran*.[39] Furthermore, the existence of a fiduciary relationship between lessors and lessees has been rejected in New Mexico.[40]

New Mexico courts have not been silent on the effect of implied covenants in mineral leases. In *Continental Potash*, the holders of certain overriding royalty interests brought suit against mine operators to recover lost royalty payments. On appeal of a trial decision for the overriding royalty owners, the New Mexico Supreme Court took a sharp turn away from the Marketable Condition Rule and reversed the lower court, concluding that implied covenants in mineral leases do not apply to overriding royalty owners for they are not entitled to the benefits of the

34. The term "at the well" was the source of legislative interest in July 1996 when the New Mexico Interim Legislative Revenue Stabilization and Tax Policy Committee held a hearing on whether a statutory definition was needed to assure proper calculation and payment of taxes and royalties to the state.

35. In recent decisions the Texas Supreme Court has held that with a "net proceeds at the well" royalty clause, royalty owners are required to bear their share of post production costs. Judice v. Mewbourn, 939 S.W. 2d 133, 137 (Tex. 1996). The court issued a similar ruling when confronted with a "market value at the well" royalty clause. Heritage Resources v. NationsBank, 939 S.W:2d 118, (Tex. 1996).

36. *See* Freeland v. Sun Oil Co., 277 F.2d 154, 157-59 (5th Cir.), cert. denied, 364 U.S. 826 (1960).

37. For a comprehensive analysis of the differing treatments of the Marketable Condition Rule, *see* Marla J. Williams, et al., *Determining the Lessor's Royalty Share of Post-Production Costs: Is the Implied Covenant to Market the Appropriate Analytical Framework?*, 41 ROCKY MTN. MIN. LAW INST., §§ 12.06[1] to 12.06[6], at 12-34 to 12-68 (1995); and *see generally* Owen L. Anderson, *The Gas Royalty Obligation: Is Royalty Ordinarily Payable on the "Raw" Gas at the Mouth of the Well or on "Marketable" Gas?*, 37 NAT. RESOURCES J. No. 3 (1997).

38. 111 N.M. 57, 60, 801 P.2d 639, 642 (1990).

39. 115 N.M. 690, 858 P.2d 66 (1993).

40. *Id.* at 701, 858 P.2d at 77.

covenants in the base lease.[41] The court noted that implied covenants are not favored in the law, rest entirely on the presumed intentions of the parties as expressed in the written contract, and for an implied covenant to be found by the Court, it must appear that the covenant was so clearly within the intent of the parties that they deemed it unnecessary to express it.[42] The Court also noted that an implied covenant cannot coexist with an express covenant that specifically speaks to the same subject and that when a contract between parties speaks to the obligation sought to be imposed, courts will not write that implied obligation into the contract.[43]

Finally, the *Continental Potash Court* adopted the analysis of the Texas Supreme Court in *Kingsley v. Western Natural Gas Co.*[44] In *Kingsley*, the Texas court held that implied covenants are disfavored, and must only be found in the presumed intent of the parties from reading the subject document as a whole, and must only be found if it is necessary to give full effect to the contract.[45]

Although no New Mexico cases address the Marketable Condition Rule, *Libby v. DeBaca*[46] and *Darr v. Eldridge*[47] address the implied duty to market oil and gas. The *Darr* Court noted that the implied duty to market required lessees "to make diligent efforts to market the production in order that the lessor may realize [benefits from the lease arrangement] on his royalty interest."[48] It is noteworthy, however, that these cases addressed the marketing of production or the seeking of a market, not who pays the cost associated with making the product marketable.

New Mexico courts have not adopted the Marketable Condition Rule or even addressed the allocation of costs between the lessor and lessee for postproduction activities that are necessary to make the production marketable. Under *Continental Potash*, the authority cited and adopted therein, and the decision of the Tenth Circuit in *Harvey E. Yates Company*,[49]

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41. *Id.* at 705, 858 P.2d at 81 (citing Howard R. Williams & Charles J. Meyers, OIL AND GAS LAW (1992)).

42. *Id.* at 704, 858 P.2d at 80.

43. *Id.* (citing Kerr McGee Corp. v. Bokum Corp., 458 F.2d 1067, 1078 (10th Cir. 1972)).

44. 393 S.W.2d 345 (Tex. App. 1965).

45. *Continental Potash v. Freeport-Morgan*, 115 N.M. at 704, 858 P.2d at 80 (1993) (citing and quoting Kingsley, 393 S.W.2d at 350-51 (citation omitted)).

46. 51 N.M. 95, 179 P.2d 263 (1947).

47. 66 N.M. 260, 346 P.2d 1041 (1959).

48. Darr, 66 N.M. at 265, 346 P.2d at 1044 (quoting Wolfe v. Texas Co., 83 F.2d 425, 432 (10th Cir. 1936)).

49. In *Harvey E. Yates*, the Tenth Circuit declined to impose implied covenants but instead turned to the terms of the lease to determine if a lessee was obligated to bear the costs of making production marketable. It stated, "[W]e have concluded that Commissioner's alternative arguments of the duty to market . . . are unavailing in this case because the state's rights here are governed by the terms of its leases with HEYCO." *Id.* at 1237, n 12.

New Mexico will probably reject the "Marketable Condition Rule" whereby a "net proceeds at the well" royalty clause will be construed to mean "gross proceeds at the tailgate of a downstream processing plant."

CONCLUSION

The adoption of the Marketable Condition Rule presents serious problems for the lessee of oil and gas rights, for it alters the relationship between lessors and lessees by rewriting the lease contract to place new burdens on the lessee. This is done with little or no regard for the underlying lease language. Since the test of the Marketable Condition Rule is met when oil and gas is sold by a willing seller to a willing buyer on the open market, where this rule has been adopted, new marketing arrangements will be developed to avoid the burdens it imposes on the lessee. Production that now is gathered, dehydrated, compressed or otherwise treated by the lessee will be sold at the well in its unprocessed state to third parties who will then perform these downstream value-enhancing activities.

These new arrangements will inject a new step into the process of producing and marketing oil and natural gas. The cost of conducting these post-wellhead activities through third parties should be higher than the cost of having the lessee perform these services. Therefore, the likely ultimate result of the Marketable Condition Rule and the oil and gas industry's response thereto, will not be higher royalty payments, but, instead, only increased production costs.