DRAFTING ROYALTY CLAUSES

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I. INTRODUCTION

The best way to draft for the future is to learn from the past. Unfortunately it is often difficult to assimilate all the lessons to be learned into a single "next" document. Instead, drafting is typically an evolutionary process where responses are made in the "next" document to the most recent bad experience. The goal of this article is to offer a *re*volutionary drafting approach that tries to identify and address the root of royalty problems--instead of merely responding to the most recent disputes that suggest a clause or a phrase might be added to shore-up the existing royalty clause structure.

The evolutionary process has resulted, in the words of Professor Merrill, in a "crazy old structure . . . like a house which has been built onto, time and again." Maurice Merrill, *The Oil and Gas Lease–Major Problems*, 41 Neb. L. Rev. 488, 491-92 (1962). Sometimes a mere remodeling of the clause just will not work. For example, in *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996), the person representing the royalty owner added the following language to the royalty clause: "provided, however, that there shall be no deductions from the value of the Lessor's royalty by reason of any required processing, cost of dehydration, compression, *transportation* or other matter to market such gas." *Heritage*, 939 S.W.2d at 120 (emphasis added). The lessee sold the gas off the leased premises and deducted "transportation" costs to calculate royalty. The lessor argued this was prohibited under the "remodeled" royalty clause. However, the drafter's remodeling project failed to change the portion of the royalty clause which provided for a royalty based upon the "market value at the well" for gas sold off the leased premises. The court concluded the royalty paid by the lessee properly reflected what was required by the express terms of the lease: "market value at the well." *Heritage*, 939 S.W.2d at 123.

The party representing the royalty owner in *Heritage* needed to build a "new" royalty clause. The remodeling job failed to accomplish what the royalty owner probably wanted, which was: first, downstream sales values; and second, downstream sales values without any deductions associated with obtaining downstream sales. Instead the royalty owner failed to obtain either benefit: values would be calculated "at the well" as opposed to values downstream of the well.

To avoid the remodeling approach to the royalty clause, we first need to deconstruct the clause as it now exists and analyze what a century of royalty jurisprudence has to tell us. We should also remember, as summarized by Professor Kuntz, the underlying purpose of the royalty clause: "The purpose of the royalty clause of an oil and gas lease is to describe the benefits which are intended to inure to the lessor as the result of the extraction of the described valuable substances by the lessee." 3 Eugene Kuntz, Kuntz a Treatise on the Law of Oil and Gas § 38.1(a), at 255 (1989) [hereinafter "3 Kuntz"] But before we begin the drafting process, we should consider whether it matters if we are representing the lessor or the lessee in our drafting.

II. COMPETITIVE NEGOTIATION FOLLOWED BY COOPERATIVE EXPRESSION OF THE RESULTS

A. Drafting Mode vs. Litigation Mode

Most thought regarding royalty issues occurs in the litigation setting as the lessor and lessee wrangle over the meaning of express royalty language and the existence and scope of implied obligations. When I was first given my topic assignment for the Advanced program, I was asked to evaluate various drafting approaches provided by attorneys representing "lessors" and those representing "lessees." However, in my opinion, when we are talking about drafting anew to define the royalty obligation, there should be no preferred "lessor" approach or "lessee" approach. Instead, the goals of the parties are aligned to try and define their royalty rights and obligations as clearly and functionally as possible.

Negotiation over the monetary impact of the royalty obligation should be vigorous and the parties will have divergent views of what is fair and proper. However, the written expression of the resulting bargain should be a matter over which the parties negotiate with a singular, noncompeting goal in mind: to memorialize the results of their negotiations so each party is fully aware of what they actually won, and lost, in the negotiation process.

B. You Can Agree to do Anything; But What Can You Practically Administer?

Having reviewed thousands of royalty clauses during the past several years I was surprised to learn that landowners are often able to obtain all kinds of intricate, convoluted, internally inconsistent, royalty provisions designed to maximize their position under the lease. Even more surprising is that lessee's agree to such unworkable provisions. I can only conclude that the language was put in the lease not to govern the day-to-day calculation and payment of royalty but rather for future use in litigation. These types of lease agreements should remind us all that whatever approach we take to drafting royalty clauses it should be something that is workable and practical–and better than the norm. If the requirements of the clause are beyond the capabilities of your lessee client's administrative system, or beyond the capabilities of your lessor client's ability to police, you do them no favors with your "new and improved" royalty clause.

Therefore, as you turn this law professor loose to consider the "new and improved," I caution you to make sure it meets your client's practical administrative capabilities and needs. My goal is to make the administration of royalty more manageable for all parties.

III. DECONSTRUCTING THE OIL ROYALTY CLAUSE

The first step toward drafting a better royalty clause is to take-apart, "deconstruct," existing clauses to fully appreciate the function various portions of each clause serves–or fails to serve. Once the reason behind each word or phrase is identified, their efficacy in stating and accomplishing the parties' goals can be evaluated.

A. The "Leased Substances"

At the lease, three types of hydrocarbons can be encountered: oil, gas, and liquids that condense out of the gas phase before it is measured, known as "condensate" or "distillate" or "natural gasoline" (collectively referred to as "condensate" in this article). 3 Eugene Kuntz, Kuntz a Treatise on the Law of Oil and Gas § 41.3(b), at 375 (1989) [hereinafter "3 Kuntz"]. The physical phase of a substance typically determines the royalty clause that will apply. For example, the gas royalty clause applies to any substance in a gaseous phase–whether it is gas from a "gas" well or casinghead gas from an "oil" well. However, although oil and condensate are both in a liquid phase, they are sold in distinct markets and may require separate treatment in a royalty clause, or an express provision indicating condensate will be valued the same as oil. For example, consider the following clause:

> The substances covered by this Lease include all gaseous and liquid hydrocarbons that can be produced from the Leased Land plus all constituent substances, regardless of their chemical composition, produced with the gaseous and liquid hydrocarbons (collectively referred to as the "Leased Substances."). For royalty purposes, any Leased Substances that are in a gaseous phase at the time they pass through a meter will be deemed "Gas" and all other Leased Substances, whether commonly known as condensate, distillate, or natural gasoline, will be deemed "Oil." The physical phase of the Leased Substance (gas or liquid) at the time it is metered or measured will determine whether it is Gas or Oil under this Lease.

B. In-Kind Oil Royalty Provisions

Traditionally, the lessor has been given a share of the actual oil produced as their royalty.

For example, a common statement of the oil royalty provides:

> The royalties to be paid by Lessee are as follows: On oil, one-eighth of that produced and saved from said land, the same to be delivered at the wells or to the credit of Lessor into the pipe line to which the wells may be connected.

AAPL Form 675 Oil and Gas Lease, reproduced in Eugene O. Kuntz, et al., Forms Manual to Accompany Cases and Materials on Oil and Gas Law 12 (West 3d ed. 1998) [hereinafter "Forms Manual"]. Why is the lessee giving the lessor a share of the oil? Why does the lessor want a share of the oil? How often does the lessor actually take their share of the oil? The answer to these questions, in the vast majority of cases, is that we don't really remember why the lessee agreed to give the lessor a share of the oil, the lessor probably doesn't know they have a share, and therefore the lessor doesn't take any action to secure their share of production. The significance of the lessor's "in-kind" royalty usually arises after-the-fact when the parties are locked in litigation.

However, the purchaser of the oil has to deal with the lessor's share of production immediately because they must obtain title to the production they are purchasing. This has resulted in the division order industry with its own cottage industry of litigation, followed by legislation, followed by more litigation. The purchaser must buy the oil from its owners. For some silly reason we continue to make these sales contracts with documents titled "Division Order." If you eliminate the lessor's in-kind royalty in oil, you can eliminate lessor division orders.

1. <u>Eliminate the Lessor's In-Kind Royalty to Avoid Environmental Risks</u>

Most private royalty owners simply do not need, and do not want, an in-kind royalty. First, if they get the oil or gas in-kind, then they must do something with it. Note that if they put their oil in a tank, and the tank leaks, the lessor has the opportunity to deal with the Environmental Protection Agency--just like their lessee! When the "lessor's" tank is cleaned, and the "lessor's" tank bottoms are taken to a disposal site, the lessor gets to become liable for cleanup of the disposal site–just like their lessee! *See, e.g., Cose v. Getty Oil Co.*, 4 F.3d 700 (9th Cir. 1993) (crude oil tank bottoms were a "hazardous substance" subject to remediation under the Comprehensive Environmental Response, Compensation and Liability Act). This prompted me, several years ago, to suggest that the lessor's "tort" benefits of a conversion action as an in-kind owner of oil are outweighed by the new environmental risks associated with being an oil "owner." As I counseled in a 1993 article (supported by a research grant from the Oil, Gas, and Mineral Law Section of the State bar of Texas):

> [T]he lessor should consider changing the typical right-to-take-in-kind oil provision to a contractual right to a share of production proceeds. Although liability for ownership of the produced *product* has not yet been imposed in environmental cases, a right to a share of the actual production makes it conceptually easier to try and characterize the lessee as the lessor's contractor for development purposes. Since lessors seldom actually market their share of oil, it may be better not to have the right to take oil in kind. This is one area where the potential benefits of environmental structuring may outweigh the revenue-collection benefits associated with ownership of a fractional share of the oil.

David E. Pierce, *Structuring Routine Oil and Gas Transactions to Minimize Environmental Liability*, 33 Washburn L. J. 76, 174 (1993).

2. <u>Eliminate the Lessor's In-Kind Royalty to Avoid Division Order and Marketing Problems</u>

Since lessors typically do nothing with their royalty oil, the first problem is trying to determine what the lessee can do with it. Many times the oil and gas lease, particularly older lease forms, do not address this issue. In those situations the lessee will typically rely upon an ill-defined body of law giving the lessee the implied contractual right to dispose of the lessor's oil. *See, e.g., Cook v. Tompkins*, 713 S.W.2d 417, 420-421 (Tex. Civ. App. 1986) (implied contract theory); *Wolfe v. Texas Co.*, 83 F.2d 425, 430-431 (10th Cir. 1936), *cert. denied*, 299 U.S. 553 (1936) (alternative theories of implied contract, agency, and ratification). Even when the lease provides for lessee purchase of the oil, typically the purchase right is at the option of the lessee. For example, the AAPL Form 675 provides: "Lessee shall have the option to purchase any royalty oil in its possession, paying the market price therefor prevailing for the field where produced on the date of purchase." Forms Manual at 12. When the lessor has not taken their oil, and therefore it is "royalty oil in its [lessee's] possession," the lessee has the option to purchase the oil at the current field market price.

Typically the "purchase" is memorialized through a division order which specifies the details of the sale. Once the term "division order" is used, all the jurisprudential and legislative baggage associated with division orders kicks-in. In addition to the law governing a sale of goods, a bastardized version of "division order" contract law is applied. This is where a contract that is expressly made irrevocable becomes revocable at will. *See, e.g., Exxon Corp. v. Middleton*, 613 S.W.2d 240, 250 (Tex. 1981) (division orders expressly continuing in force during the life of the lease were nevertheless revocable at will by the lessor).

The best way to avoid division order and marketing authority disputes is to eliminate the lessor's ownership interest in oil. If title to 8/8ths of the oil never leaves the lessee, there is no need to seek title from the lessor. Therefore, I would advocate, whether representing the lessor or the lessee, that the lessor's oil royalty not be in-kind but instead a measured sum of money. *See* David E. Pierce, *Resolving Division Order Disputes: A Conceptual Approach*, 35 Rocky Mtn. Min. L. Inst. 16-1, 16-50 (1990) ("Perhaps the best approach would be to eliminate the need for any sort of division order or production sales agreement from the lessor. This could be done by eliminating the lessor from the marketing transaction altogether."). This means the oil royalty clause will be very similar to the gas royalty clause.

C. Value-Based Royalty Provisions

I recently examined why we tend to have so much royalty calculation litigation, and posited a "royalty value theorem" which states:

> 'When compensation under a contract is based upon a set percentage of the value of something, there will be a tendency by each party to either minimize or maximize the value.'

David E. Pierce, *What's Behind the Valuation Controversy Anyway?* Federal and Indian Oil and Gas Royalty Valuation & Management III 1-1 (Rocky Mtn. Min. L. Fdn. 2000). Therefore, any language in the royalty clause that permits either party to argue for greater or lesser values per barrel of oil or MMBtu of gas creates the opportunity for dispute. A major drafting goal should be to try and reduce, to the maximum extent possible, the ability of the parties to "interpret" the royalty obligation to enhance their position under the royalty value theorem.

As each variable is added to the royalty valuation equation, the opportunity for the royalty value theorem to operate increases. For example, under the oil royalty clause one variable when the lessor receives an in-kind royalty is determining what happened to the oil. Did the lessee sell it under an implied contract to sell for the lessor? Did the lessee exercise its option to purchase the oil at the current market price? These variables can be eliminated by eliminating the in-kind royalty and replacing it with a right to a payment of money. Note this alternative approach does not increase the calculation variables because even under the in-kind royalty the oil value must be determined–unless the lessor actually takes their oil in-kind–which as noted previously seldom occurs. By eliminating the in-kind royalty provision we also eliminate two additional bodies of law that would impact the parties' rights: "division order" law and Article 2 of the Uniform Commercial Code which would govern the sale of the oil by the lessor to the lessee or to some third party.

Of course, if lessors actually took their oil in kind, the valuation issue at the lease level would be eliminated. The focus would shift to issues concerning the point of delivery, condition of the commodity at delivery, and measurement. These issues should be more manageable than valuation issues. However, valuation and other problems may sneak back into the process if lessees try to purchase the lessor's oil using a division order. I think a simple way to manage the division order problem is, as I have suggested elsewhere, don't ever use a document to buy oil that is titled or structured as a division order. David E. Pierce, *Resolving Division Order Disputes: A Conceptual Approach*, 35 Rocky Mtn. Min. L. Inst. 16-1, 16-49 (1990). Instead, call the document what it is: an "Oil Sales Contract" and structure it around Article 2 of the Uniform Commercial Code.

D. Measurement Provisions

Whether the royalty is based upon a share of the production, or a share of the value, in both instances measurement will be a major variable to consider. Since royalty is "a share of" (a fraction of, a percentage of) something, we must determine what the "something" is to ascertain the royalty due. Oddly, most oil and gas lease forms do not address measurement. Instead, measurement provisions are usually found in division orders. Many times the division order fails to address the matter. The Texas statutory oil division order form contemplates the parties will rely upon the "purchaser" to determine measurement by providing: "Purchaser shall compute quantity and make corrections for gravity and temperature and make deductions for impurities." Tex. Nat. Res. Code Ann. § 91.402(d) (Vernon Supp. 1999).

Litigation over oil and gas measurement issues is now with us and it would seem like a proper subject to address as part of the royalty clause. The only problem is "how" to address the issue. There is probably a reason why measurement is not addressed in specific terms in the oil and gas lease. This is an area where flexibility for new, more precise, measurement practices is warranted today even more than in the past. As Professor Kuntz noted: "So long as the method used by the lessee is fair and efficient and results in a fair accounting to the lessor for royalty oil, such lessor has no basis for complaint about the test used." 3 Eugene Kuntz, Kuntz a Treatise on the Law of Oil and Gas § 39.2(d), at 290 (1989). To articulate this concept as a contractual obligation, and reciprocal right, the royalty clause might provide:

> Lessee will use measurement devices and techniques designed to efficiently and accurately measure all leased substances.

The lessor should be given the opportunity to confirm the accuracy of measurement devices. For example, consider the following procedure:

> Annually Lessee will have an independent contractor calibrate and confirm the accuracy of the meters and other equipment used to measure leased substances. Lessee will provide Lessor with five days advance notice so Lessor, and/or Lessor's representative, can be present when the independent contractor is at the meter or measurement site. Lessor will be copied on all correspondence from the independent contractor concerning measurement of the leased substances.

Equally important as the actual measurement of the production is the precise point in the production process where measurements will be made. All measurements should take place at the lease level, or pooled unit, before the production is commingled with any other production. The lease could provide:

> Measurement of leased substances will occur before the production is removed from the leased land.

E. Objective Valuation Standards for Oil

The simplest royalty clause would provide for the measurement of production at or near the point of production to determine the oil volume and gravity. This would be followed by an objective valuation standard that is acceptable to both parties.

1. Select a Mutually Acceptable Method to Value Produced Oil

The first step in the process is ascertaining what the objective value is assigned to oil at a particular place and time. For example, for June 2000 assume the average daily sales price for oil under a recognized pricing formula or index acceptable to both parties was $30.00. Assume further this is the price being paid for oil delivered in Cushing, Oklahoma, based upon a trading unit of 1,000 U.S. barrels of light, sweet crude oil of a deliverable grade having 0.42% sulphur by weight or less, and not less that 37° API gravity nor more than 42° API gravity. This is the standard trading unit used for "Light, Sweet Crude Oil" for trading on the New York Mercantile Exchange ("NYMEX"). *See* www.nymex.com. To the extent the oil produced at the lease does not fall within these quality, quantity, and location parameters, a value adjustment is required to account for the actual value of the oil being produced.

If there were 300 barrels of oil produced from the leased land during the month of June 2000, and the royalty clause provided for payment of a 1/5th royalty, the first step of the valuation under the facts would be (300 x 1/5 = 60) x ***$30*** = $1800. The $30 figure appears to be what has prompted most of the litigation in the oil royalty area. The primary claim by lessors is that the price used for this portion of the equation is subject to manipulation by the lessee and crude oil purchasers and therefore does not reflect the actual value of the oil. Lessees respond that the prices paid for oil at the lease have reflected its value, *at the lease*. The basic problem is lessors see a bigger, and often fundamentally different, number assigned to crude oil at a downstream location, such as the NYMEX price, and compare it with what they are being paid. It may take a lawsuit to determine whether the variation between the two is too much, too little, or just right–or simply irrelevant. With proper analysis of the historical difference between NYMEX prices and prices actually paid for crude oil in a producing area, lessees and lessors should be able to calculate an appropriate discount from the NYMEX price to approximate, for royalty purposes, crude oil values in the field of production.

The major improvement in using the NYMEX price (or whatever objective index pricing the parties may select) is it addresses the lessor's major complaint regarding the valuation of oil. It also simplifies the royalty calculation process, and assists the lessor in policing the lessee's compliance with its royalty obligations. The lessor's ability to police the lessee's compliance with the royalty clause is important. If the lessor, on a monthly or annual basis, is able to easily confirm that they have been paid what they are due, it should make for better relations between the parties. Also, if the lessor discovers they have been improperly paid (whether too much or too little), the matter can be identified in a timely manner so it can be remedied before the stakes become so high the parties become entrenched in a litigation mode. To protect against such lingering disputes, the parties may want to incorporate an audit and contractual limitations period provision into the royalty clause similar to the following:

> Lessor, through a certified public accountant representative experienced in oil and gas accounting ("CPA"), and at Lessor's sole expense, has the right to audit Lessee's books and records to confirm the accuracy of royalty payments made under this Lease. If the audit reveals an alleged underpayment, Lessor's CPA shall state the details of its findings in writing and deliver it to the Lessee. No claim relating to a royalty payment made more than 730 days prior to the CPA's notice of alleged underpayment will be considered; such payments will be deemed to have been properly made and will not be open to challenge in any manner by the Lessor for any reason.

Although lessees may be a little gun-shy (litigation-shy) to even the suggestion of a NYMEX or downstream index price for calculating royalty, we must always keep in mind the task at hand: ***with a clean slate, and no***

preexisting contractual obligations, how can we most effectively define the royalty obligation? If an existing lease provides for a royalty based upon the value of oil "at the well" or "in the field," then NYMEX and downstream index prices may have little or no correlation to the value of oil where produced. But as we look forward to the "next lease" we draft, the NYMEX and downstream index prices offer a useful starting point for valuing the oil royalty obligation. However, even in the "next lease" we must grapple with the difficult problem of defining the correlation between oil produced at the well or in the field and oil, continuing our hypothetical, in 1,000 barrel trading units, of a specified grade, physically located in Cushing, Oklahoma.

2. Defining the Discount

The primary focus of royalty clause negotiations under the NYMEX/index valuation approach will be defining the discount that will be used to adjust for differences in downstream values versus values at the well or the field where production occurs. Lessees should begin the process by analyzing how crude oil prices in the area where the lease is located compare to NYMEX or other downstream index prices. NYMEX pricing for oil has been around since 1983 so there is over 17 years of data to conduct price comparisons to define the correlation between field prices in an area and NYMEX prices. Since there have been considerable market gyrations during this 17-year period, it should provide useful information to begin fashioning an appropriate discount. For example, if the spread between NYMEX and field prices has historically been 15% for a particular field, this may be the appropriate discount to seek in lease negotiations.

However, until production from a particular well is actually obtained, the quality of the oil is an unknown. For example, the oil, relative to the NYMEX benchmark, may be high in sulphur and may be above or below the 37/42° API gravity range. One approach to this is to incorporate into the royalty clause a gravity adjustment scale, similar to that used by crude oil purchasers, which adjusts the value, typically in 1/10th degree increments, for oil that falls outside the NYMEX benchmark. *See, e.g.*, www.kochoil.com gravity adjustment scale for its crude oil postings. The negotiated gravity adjustment scale would become part of the lease contract between the parties. For example, the parties might agree as follows:

> The "NYMEX Price" (a defined term) will be adjusted to reflect the actual gravity of the "Lease Oil" (a defined term) by making a deduction of \$0.015/barrel to the NYMEX Price for each 1/10th of degree below 37° API gravity or each 1/10th of a degree above 42° API gravity.

The actual deduction per barrel, the gravity breaks at which deductions will begin, and whether the deduction will be the same for oil above and below the NYMEX Price API gravity range, will all be matters for negotiation–as will whether any gravity deduction will be used at all. The parties might agree to simplify the calculation by addressing future oil quality risk in the negotiated percentage discount on the NYMEX Price. At \$30/barrel oil an agreement to increase the discount by 1% would provide for 30¢ worth of gravity fluctuation risk. Using the gravity adjustment provisions noted above, this would allow for oil having an API gravity as low as 17° (20° or 200/10ths of a degree x \$0.015) and as high as 52°.

The parties may also need to provide for the sulphur content of the oil and its classification as "sweet" or "sour." It may be possible to calculate a discount using the NYMEX "sweet" standard (0.42% or less sulphur by weight) as a benchmark.

Regardless of the actual discount number agreed upon, the important aspect is that it is a contractually-established number. It does not depend upon the subsequent actions of the lessee. Therefore, although one party may not like the number at any given time, they know it is the product of their (or their predecessor's) agreement and not the product of any sort of real or imagined manipulation on the part of the lessee. In many ways, the risk the parties assume in this situation is no different from the risk they assume when they agree to a fixed fractional royalty at the time the lease is entered into: for example, is 1/5th too much or too little?

To illustrate the calculation, assume the lessor and lessee have agreed to a 1/5th royalty on a defined amount of value assigned to oil production. The first step will be to ascertain the average of the daily closing NYMEX prices for light, sweet crude oil for the month of production (the details for how this can be done are contained in Appendix A to this article); again assume for the month of June 2000 that average was \$30.00/barrel. Further assume the parties have agreed to a flat (no separate gravity adjustment) 16% discount on the NYMEX price to account for any difference in value between the oil as produced and the NYMEX price. Assume during the month of June 300 barrels of oil were produced.

Therefore, the royalty calculation equation would be:

> Royalty Fraction x [(NYMEX Price x Discount) x Production Volumes] = Royalty Due

Using the assumed numbers the royalty calculation is as follows:

1/5 x [(\$30 x 84%) x 300] = Royalty Due

1/5 x [\$25.20 x 300] = Royalty Due

1/5 x \$7,560.04 = Royalty Due

\$1,512.00 = Royalty Due

The royalty clause could express the required formula as follows:

> Lessor's royalty on Liquid Hydrocarbons (a defined term) is 1/5th of an amount of money calculated by taking 84% of the NYMEX Price (a defined term) multiplied by the Royalty Volume (a defined term).

F. The Importance of Trying to Approximate Wellhead, Lease, or Field-of-Production Values

The parties should endeavor to use royalty calculations that at least attempt to approximate the value of the oil where it is produced. If the lessor wants to negotiate for more net revenue, this should be done by seeking a larger royalty fraction as opposed to manipulating the discount. During the life of the lease the discounted wellhead value may be used for purposes other than the calculation of royalty–such as taxation. Therefore, in an effort to avoid having to conduct separate valuations for royalty and taxation, the royalty equation should be negotiated to serve other valuation needs.

However, to the extent the discount is not a negotiated attempt to reflect wellhead, lease, or field-of-production values, this fact should be expressly noted in the lease. For example, suppose the lessor demands, and successfully negotiates for, a discount from the NYMEX price to a main transportation delivery point in West Texas–as opposed to a discount based upon wellhead values. Assume this results in a 10% discount instead of a 16% discount. This 6% difference needs to be explained in the lease to address the risk that taxing authorities will try to use the 10% discounted value as an analog for wellhead values. Perhaps the best way to do this is to expressly state that the discount has been calculated on the basis that the lessor is entitled to the value of the oil not at the wellhead but rather at the specified downstream receipt point. It should also be remembered that although you take these precautions to try and contractually define royalty values, the results are just that: a *contractual* definition of the obligation between lessor and lessee as opposed to the lessee and non-party taxing authorities.

The goal should be to try and negotiate for a discount that reflects wellhead values and, if in practice it actually reflects such values, it can be used for other valuation purposes. However, to the extent the negotiated lease values are not reflective of wellhead values (either more or less than wellhead values), they should not be used for wellhead valuation purposes, unless they can be efficiently adjusted to reflect wellhead values.

IV. DECONSTRUCTING THE GAS ROYALTY CLAUSE

Many of the observations made in the oil portion of this article apply equally to gas. For example, the problems associated with taking oil in kind apply as well to gas, the objective value problem is essentially the same, the measurement and audit issues are the same. Therefore, many of the provisions, such as the measurement and audit portions of the clause, will apply to oil and gas. The objective value analysis will be the same, and the same sort of value benchmarks can be used to address value problems. However, gas does present its own unique problems which will require special treatment. For example, historically lessees have dedicated gas reserves to serve certain pipeline customers. Today this dedication will rarely be on a specific lease basis, but the lessee may, in effect, be reserving a supply of gas from one or more leases to serve a particular purchaser. The problem is the lessee may be receiving payments from a purchaser to maintain a gas supply in reserve, which means the gas may not be currently produced. This creates issues concerning royalty on the "reservation charge" portion of the gas purchase agreement, the failure to produce all gas attributable to the lessee and lessor the well can produce, and "gas balancing" issues.

A. Objective Valuation Standards for Gas

Most gas litigation has focused on three related issues: (1) Where should gas be valued for royalty purposes? (2) How should gas be valued? and (3) What post-extraction expenses can be deducted from gas values before calculating the royalty due? The response I recommend for these issues is identical to the response suggested for oil. First, as with oil, the goal is to select a royalty benchmark the parties have confidence in and can readily identify. The goal is to use an objective standard that will value gas at a particular time and place. For example, for June 2000 assume the average daily sales price for gas under a recognized pricing formula or index acceptable to both parties was $3.00 per MMBtu. Assume further this is the price being paid for gas delivered to Sabine Pipe Line Co.'s Henry Hub in Louisiana, based upon a trading unit of 10,000 MMBtus that meets the pipeline specifications in effect at the time of delivery. This is the standard trading unit used for "Henry Hub Natural Gas" for trading on the NYMEX. *See* www.nymex.com. As with oil, to the extent the gas produced at the lease does not fall within these quality, quantity, and location parameters, a value adjustment is required to account for the actual value of the gas being produced.

Therefore, once an objective formula is selected, whether NYMEX-based or based upon spot sales at other pipeline receipt points, the major task will be negotiating the appropriate discount the parties will use to try and approximate the value of the gas at the wellhead. Gas trading on the NYMEX has taken place since 1990 so we have a decade of price history to analyze and compare with actual wellhead sales to try and define a discount. As with oil, the discount should be tied to wellhead values in the event the net price is used for severance tax purposes. The royalty clause could express the required formula as follows:

> Lessor's royalty on Gas (a defined term) is 1/5th of an amount of money calculated by taking 81% of the NYMEX price (a defined term) multiplied by the Volume (a defined term).

B. Production Practices–The Volume Variable

Once the value issue is addressed, the next issue is volume. The royalty valuation approach I have suggested has nothing to do with what the lessee actually does with the gas. The NYMEX price under the royalty clause may set a royalty at $3.00/MMBtu; whether the lessee in fact obtains $9.00/MMBtu or $1.00/MMBtu simply does not matter. However, the *volume* of gas produced may be impacted by what the lessee does with the gas. For example, suppose the lessee enters into a three-year contract to supply gas at $3.00/MMBtu but also receives an additional $1.25/MMBtu as consideration for guaranteeing that certain volumes of gas will be available at various delivery points at the purchaser's demand. The additional $1.25/MMBtu obtained by the lessee is of no concern to the lessor–they simply have no right to it. However, if the lessee uses the leased land as a reserve to meet the purchaser's potential gas needs, *and this results in a reduction of the volumes available for current production from the leased land*, the lessor will have a basis to complain.

To protect the lessor in this situation, the lease should require that the lessee produce the lease at the maximum prudent rate it is physically capable of producing under the law. For example, the lease could provide:

> Lessee, consistent with prudent operating practices and applicable law, will at all times operate all wells on the leased land to maximize current production from the leased land.

If the lessee desires to restrict production to engage in a certain type of marketing program, this should be expressly negotiated and agreed to by the lessee and lessor either in the original lease, or at the time the program is developed.

In today's gas marketing system lessee's should be able to currently produce and sell their gas without concern for gas balancing issues. If one purchaser fails to take, arrangements can often be made to sell the gas to another purchaser. Sometimes, however, due to events beyond the lessee's control, they will not be capable of producing their working interest share of gas from the leased land. Today, such imbalances should be short-lived and not become a problem. Under these circumstances, attempting to address gas imbalances in the oil and gas lease may not be worth the effort. However, if the parties want to address the issue, the following approach would protect the lessor's interest in maximizing current production:

> In the event Lessee is unable to produce and take its share of the gas from a well on the Leased Land, and other owners are taking gas from the well, Lessor will be paid royalty based upon the total volumes actually produced from the well proportionately reduced to reflect Lessee's ownership interest in the well.
>
> In the event Lessee subsequently makes-up the gas imbalance by taking volumes in excess of the Lessee's ownership interest in the well ("Excess Volumes"), Lessee will not be obligated to pay royalty on the Excess Volumes.

Under this approach, the lessor is always current on production and the financial impact of the lessee's future make-up is solely a matter between the lessee and the other working interest owners.

V. OTHER CONSIDERATIONS

The lease should provide for an alternative mechanism for calculating royalty in the event the lease outlives the selected formula or index. The simplest approach would be to provide for a royalty measured by "market value" at a selected marketing location, such as "at the well," "in the field," or "at the terminus of the field gathering system." Alternative indexes may be difficult to pre-select because it will often require the parties to renegotiate the appropriate discount to be applied to the selected index price.

Regarding the administration of disputes under the royalty clause, and the balance of the oil and gas lease, the parties should consider whether an arbitration clause would be appropriate. *See* Loretta W. Moore & David E. Pierce, *A Structural Model for Arbitrating Disputes Under the Oil and Gas Lease*," 37 Natural Resources J. 407 (1997). There are also other, non-calculation issues, that can significantly impact the lessor's royalty, such as the lessee's failure to seek a non-participating royalty owner's ratification of the oil and gas lease and pooling arrangements. Consider the following clause used by an attorney in Texas:

> No well shall be drilled on, under, or through any portion of the leased premises which are subject to an outstanding non-participating royalty interest, or at a location which is not a legal location pursuant to this Lease or the rules and regulations of the Railroad Commission of Texas, unless such non-participating royalty interest owner has ratified this Lease in all respects. In the event a well or wells are drilled on or

> under any portion of the leased premises which are subject to a non-participating royalty interest, the owner of which has not ratified this Lease in all respects, or any unit or pooled unit formed pursuant to this Lease, then Lessee shall assume all responsibility for and pay out of Lessee's interest to Lessor, any disproportionate allocation of royalty which may result therefrom.

VI. CONCLUSIONS

My goal has been to offer, for the oil and gas bar's consideration, a neutral royalty clause that should be acceptable, generically, to both royalty owner and producer. Negotiation under the clause focuses on the selection of an acceptable objective formula for valuing production and the appropriate discount to adjust for the location, quality, and quantity of the production at the point of extraction. The complete clause is found at APPENDIX A. It is a work-in-progress to illustrate the underlying goals lessors and lessees should strive for whether through a NYMEX formula, a published index, or some other objective standard for calculating royalty.

APPENDIX A

Illustrative Royalty Clause

1. ROYALTY RIGHTS & OBLIGATIONS. Lessor will be paid a royalty on the following terms:

a. Definition of "Leased Substances." The substances covered by this Lease include all gaseous and liquid hydrocarbons that can be produced from the Leased Land plus all constituent substances, regardless of their chemical composition, produced with the gaseous and liquid hydrocarbons (collectively referred to as the "Leased Substances.").

b. Definition of "Oil" and "Gas." For royalty purposes, any Leased Substances that are in a gaseous phase at the time they pass through a meter on the Leased Land will be deemed "Gas" and all other Leased Substances, whether commonly known as condensate, distillate, or natural gasoline, will be deemed "Oil." The physical phase of the Leased Substance (gas or liquid) at the time it is first metered or measured on the Leased Land will determine whether it is Gas or Oil.

c. Definition of "NYMEX Price."

Futures Contract Trading Period. The Futures Contract Trading Period ("Trading Period") is the period of time established by the New York Mercantile Exchange ("NYMEX") during which futures contracts are traded for Oil, and for Gas, for physical delivery during the calendar month immediately following the last day of the Trading Period.

NYMEX Price for Oil. The NYMEX Price for Oil is equal to the arithmetic average of the daily per barrel settlement prices for the NYMEX Division Light, Sweet Crude Oil futures contract during the Trading Period that immediately precedes the calendar month in which Oil is extracted from the Leased Land minus any applicable Gravity Adjustment and Sour Adjustment. The Gravity Adjustment is equal to a deduction of $0.015/barrel for each 1/10th of degree below 37° API gravity or each 1/10th of a degree above 42° API gravity. The Sour Adjustment is equal to a deduction of $1.70/barrel for Oil that has in excess of 0.42% sulfur by weight. A barrel is equal to 42 gallons.

NYMEX Price for Gas. The NYMEX Price for Gas is equal to the arithmetic average of the daily per MMBtu settlement prices for the NYMEX Division Henry Hub Natural Gas futures contract during the Trading Period that immediately precedes the calendar month in which Gas is extracted from the Leased Land.

d. Measurement. Measurement of Oil and Gas will occur before the production is removed from the Leased Land. Lessee will use measurement devices and techniques designed to efficiently and accurately measure all Oil and Gas. The quantities of Oil and Gas, measured on the Leased Land, will determine the "Production Volume" for the royalty calculation equation contained in subsection **e**. Annually Lessee will have an independent contractor: (1) calibrate and confirm the accuracy of the meters and other equipment used to measure Oil and Gas; (2) determine the gravity of the Oil; (3) determine the sulphur content of the Oil; and (4) determine the heating content (MMBtus) of the Gas as it enters the meter. Lessee will provide Lessor with five days advance notice so Lessor, and/or Lessor's representative, can be present when the independent contractor is at the meter or measurement site. Lessor will be copied on all correspondence from the independent contractor concerning measurement of the volume and quality of the Oil and Gas.

e. Royalty Calculation. Lessor's royalty on Oil is 1/5th of an amount of money calculated by taking 84% of the NYMEX Price multiplied by the total Oil Production Volume for the calendar month. Lessor's royalty on Gas is 1/5th of an amount of money calculated by taking 81% of the NYMEX price multiplied by the total Gas Production Volume for the calendar month.

f. Alternative Royalty Calculation if Unable to Determine NYMEX Price. In the event the information necessary to determine the NYMEX Price ceases to be available, the parties will attempt to agree on a substitute pricing formula or index, and related location and value adjustments. In the event the parties are unable to agree on a substitute basis for calculating royalty within 60 days following the date the NYMEX Price information ceases to be available, the basis for calculating royalty on all Oil and Gas, following failure of the NYMEX Price, will be as follows:

> **e. Royalty Calculation.** Lessor's royalty on Oil and Gas is 1/5th of an amount of money calculated by taking the market value of the Oil and Gas, while physically located on the Leased Land, at the time it is produced and measured on the Leased Land, multiplied by the total Oil and Gas Production Volume for the calendar month. Market value will be determined by considering sales of the Oil and Gas by Lessee, and sales of Oil and Gas by Lessee and others when the sales are substantially similar to those from the Leased Land by being comparable in location, time, quantity, quality, and available marketing outlets.

g. Lessee Marketing Obligations; Gas Imbalances. Lessee, consistent with prudent operating practices and applicable law, will at all times operate all wells on the Leased Land to maximize current production from the Leased Land. In the event Lessee is unable to produce and take its share of the gas from a well on the Leased Land, and other owners are taking gas from the well, Lessor will be paid royalty based upon the total volumes actually produced from the well, proportionately reduced to reflect Lessee's ownership interest in the well attributable to the Oil and Gas Lease ("Ownership Interest"). In the event Lessee subsequently makes-up the gas imbalance by taking, during any calendar month, volumes in excess of the Lessee's Ownership Interest in the well ("Excess Volumes"), Lessee will not pay royalty on the Excess Volumes.

h. Audit Rights and Limitation of Lessor's Right to Challenge Payments. Lessor, through a certified public accountant representative experienced in oil and gas accounting ("CPA"), and at Lessor's sole expense, has the right to audit Lessee's books and records to confirm the accuracy of royalty payments made under this Lease. If the audit reveals an alleged underpayment, Lessor's CPA shall state the details of its findings in writing and deliver it to the Lessee. No claim relating to a royalty payment made more than 730 days prior to receipt of the CPA's written notice of alleged underpayment will be considered; such payments will be deemed to have been properly made and will not be open to challenge in any manner by the Lessor or Lessee for any reason.

SAMPLE ROYALTY CALCULATION
(Using Actual Data for September Production)

Assume: During the month of September the Lessee produces 1000 barrels of oil and 50,000 MMBtus of natural gas from the Leased Land. The oil is sweet and has a 39° API gravity. No liquids condense from the gas prior to metering.

These calculations could be included with the royalty owner's check.

Step #1. ***Identify the Applicable Futures Contract Trading Period for Oil and for Gas.***

The Trading Period for Oil produced during the calendar month of September 2000 began on 21 July 2000 and ended on 22 August 2000. NYMEX rules provide the trading period for physical delivery of Oil terminates on the third business day prior to the 25th calendar day of the month preceding the delivery month. Therefore, the trading period for physical deliveries of Oil in September 2000 will begin the day following the last day for trading futures for August delivery, which would be July 21, and end on the third business day prior to the 25th of August, which would be 22 August.

The Trading Period for Gas produced during the calendar month of September 2000 began on 28 July and ended on 29 August. NYMEX rules provide the trading period for physical delivery of Gas terminates on the third business day prior to the first calendar day of the delivery month. Therefore, the trading period for physical deliveries of Gas in September 2000 will begin the day following the last day for trading futures for August delivery, which would be July 28, and end on the third business day prior to the 1st of September, which would be 29 August.

Step #2. ***Identify Daily Settlement Price for Each Business Day of the Trading Period.***

Oil:	07/21 $30.93	07/24 $28.18	07/25 $28.32	07/26 $27.81	07/27 $28.02
	07/28 $28.18	07/31 $27.43	08/01 $27.79	08/02 $28.40	08/03 $28.66
	08/04 $29.96	08/07 $29.46	08/08 $29.12	08/09 $30.12	08/10 $30.35
	08/11 $31.34	08/14 $31.94	08/15 $31.67	08/16 $31.80	08/17 $31.94
	08/18 $31.99	08/21 $32.66	08/22 $31.22	**23 Oil Trading Days**	

Gas:	07/28 $3.85	07/31 $3.77	08/01 $3.98	08/02 $4.05	08/03 $4.25
	08/04 $4.30	08/07 $4.39	08/08 $4.41	08/09 $4.49	08/10 $4.42
	08/11 $4.47	08/14 $4.32	08/15 $4.23	08/16 $4.31	08/17 $4.41
	08/18 $4.44	08/21 $4.71	08/22 $4.52	08/23 $4.52	08/24 $4.52
	08/25 $4.63	08/28 $4.69	08/29 $4.62	**23 Gas Trading Days**	

Step #3. ***Add the Daily Settlement Prices Together and Divide by the Number of Trading Days to Establish the Arithmetic Average.***

Oil: $687.29 ÷ 23 = $29.88

Gas: $100.30 ÷ 23 = $ 4.36

Step #4. ***Take the NYMEX Price and Make Any Necessary Quality Adjustments.***

Oil: None required for the oil being produced.

Gas: None required.

Step #5. ***Apply the NYMEX Price to the Negotiated Discount.***

Oil: $29.88/barrel x 84% = $25.10

Gas: $4.36/MMBtu x 81% = $3.53

Step #6. ***Apply the Discounted NYMEX Price to the Production Volumes.***

Oil: 1000 x 1/5 = 200 barrels

200 barrels x $25.10 = $5,020.00 **Oil Royalty Due**

Gas: 50,000 x 1/5 = 10,000 MMBtus

10,000 MMBtus x $3.53 = $35,300 **Gas Royalty Due**