THE COMPRESSION OF NATURAL GAS – IS IT PRODUCTION OR POST-PRODUCTION? IS IT DEDUCTIBLE FROM ROYALTIES? IF SO, HOW MUCH?

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In almost all gas fields, compression is, or will be, a necessary operation. The rising price of natural gas has caused the cost of moving the gas from the field to the consumer to significantly increase. One important reason for the cost accretion is that the equipment used for these operations burn natural gas as fuel. The higher the price of natural gas, consequently, the higher the cost of these ancillary activities. High costs also create another phenomenon – litigation between the lessor and lessee concerning who shoulders them and whether they are reasonable.

There are many cases concerning lessor/lessee disputes relating to the drilling of wells and the base price upon which the lessee pays royalties. Though much has been written by commentators,[1] a less common dispute between the parties to a lease under Texas law centers around the compression activities of the producer, and whether or not the costs associated with

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[1] 3 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW: MANUAL OF TERMS, § 645 (2004); Scott Lansdown, *The Marketable Condition Rule*, 44 S. Tex. L. Rev. 667 (2003); Adam Marshall, *Rogers v. Westerman Farm Co.: Burdening Lessees With an Implied Duty to Deliver Gas to a Marketable Location*, 56 Okla. L. Rev. 233 (2003); Scott Lansdown, *The Implied Marketing Covenant in Oil and Gas Leases: The Producer's Perspective*, 31 St. Mary's L.J. 297 (2000); Owen L. Anderson, *Royalty Valuation: Should Overriding Royalty Interests and Nonparticipating Royalty Interests, Whether Payable in Value or in Kind, Be Subject to the Same Valuation Standard as Lease Royalty?* 35 Land & Water L. Rev. 1 (2000); Mark D. Christiansen, *A Landsman's Guide to Drafting Provisions for the Allocation of Gas Marketing-Related Costs under the Oil and Gas Lease*, 45 Rocky Mt. Min. L. Inst. ch. 21 (1999); David B. Pierce, *The Missing Link in Royalty Analysis: An Essay on Resolving Value-Based Royalty Disputes*; 5 Tex. Wesleyan L. Rev. 185 (1999); Brian S. Tooley and Keith D. Tooley, *The Marketable Product Approach in the Natural Gas Royalty Case*, 44 Rocky Mt. Min. L. Inst. ch. 21 (1998); John R. Woodward, *Post Production Deductions—Heritage v. NationsBank*, 43 Landman 11-25 (May/June 1998); William D. Watson, *Current Royalty Issues in the United States*, [1998] OGLTR 181-85 (focusing on post-production costs issues); Marla J. Williams & William D. Watson, *The Deductibility of Postproduction Costs in Determining Royalty and Overriding Royalty under Nonfederal Leases*, 48 Oil & Gas Inst. ch. 6 (1997); Owen L. Anderson, *Calculating Royalty: 'Costs' Subsequent to Production—'Figures Don't Lie, but . . .*, 33 *Washburn L.J.* 591 (1994); James Hardwick and J. Kevin Hayes, *Gas Royalty Issues Arising from Direct Gas Marketing*, 43 *S.W. Legal Found. Oil & Gas Inst.* 11-1, at 11-14 (1992).

those operations should be paid proportionately by the lessee and lessor. As to royalties on natural gas production, this issue is becoming more important with each passing year because these operations directly impact the value of the gas produced from a lease and, might, determine whether a well or wells are producing in paying quantities.[2]

Natural gas post-production activities include dehydration, processing, gathering, transportation and compression. Depending upon the quality of the natural gas produced from a particular lease or field, the only guaranteed operations are gathering, transporting, and (later on) compression. This article will focus upon compression as a post-production transportation operation and the proportionate sharing of the associated costs between working interest and royalty interest owners.[3] While reviewing this paper, the reader needs to keep the following in mind – a royalty interest is "the landowner's *share of production*, free of the expenses of production."[4] With that in mind, there are four questions to be answered concerning compression:

A. What is it?

B. Is it production or post-production?

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[2] Whether a well is producing in "paying quantities" is determined "not only by the amount of production but also the ability to market the gas at a profit. Whether there is a reasonable basis for the expectation of profitable returns from the well is the test. If the quantity is sufficient to warrant the use of the gas in the market, and the income therefrom is in excess of the actual marketing cost, and operation costs, the production satisfies the term 'in paying quantities.''' *Clifton v. Koontz*, 160 Tex. 82, 325 S.W.2d 684, 691 (1959). The question is would a reasonably prudent operator have operated the well for a profit and not merely for speculation. *Id.* All relevant facts are to be considered. *Id.*

[3] Working interest is the operating interest pursuant to an oil and gas lease. A working interest owner enjoys the exclusive right to explore for and produce minerals on the land. 8 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW: MANUAL OF TERMS, 1191 (2004). A royalty interest owner is entitled to a share of production if, as and when there is production, free of the costs of production. *Id*. at 952.

[4] *E.g. Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 121-22 (Tex. 1996).

C. How is it affected by the marketable condition rule?

D. How much should be paid?

What is compression?

Compression is merely a function of increasing the pressure in the natural gas stream in order to assist in its transportation from the field to the consumer. During the life of a natural gas well, the pressure at which the gas flows through the mouth of the well at the beginning of its production cycle is higher than the pressure at which the gas flows through the mouth of the well at the end of the production cycle. It follows that during the interim, the pressure at which the gas flows from the well gradually decreases. This natural event has consequences on the movement of the gas from the well bore to the ultimate consumer.

Except on rare occasions, natural gas must be transported to the consumer through a pipeline.[5] In order for the gas to be injected into a transmission pipeline, there are certain minimum pressure requirements. Typically, the minimum pressure requirement for transmission gas pipelines is no less than 1,000 pounds per square inch ("psi"). At the beginning of their producing lives, most natural gas wells easily meet these minimum requirements. Consequently, at the beginning of the production cycle, the natural gas usually flows through the mouth of the well bore in excess of 1,000 psi, travels through a gathering line and then to the transmission pipeline, and is easily injected. When the pressure from the mouth of the well bore drops below

[5] There are situations wherein natural gas has been trucked from a well location to a pipeline. Due to the expense involved, this method is rarely used.

1,000 psi, however, the gas must then be "compressed" in order for it to reach the minimum 1,000 psi requirement of the transmission lines.

Simply stated, compression is the squeezing of the natural gas stream during the transportation process.[6] The low pressure natural gas flows at its natural pressure through the gathering and/or trunk lines and into a compressor station,[7] where it is then squeezed so that when the natural gas stream exits the compressor, it does so at a higher pressure that will be sufficient for injection into the next line in the transportation chain. If the downstream pressure is still insufficient, the gas stream will require an additional stage of compression in order to meet minimum pipeline standards. Depending upon the age of the wells and their production cycle, some gas streams require multiple stages of compression in order to meet minimum pressure requirements.

Is Compression a Production Activity?

Natural gas is "produced" when it is severed from the land.[8] Most compression does not involve an operation that occurs "down-hole" or inside the well bore which causes gas to come to the mouth of the well. Most compression of natural gas streams occurs after the natural gas has moved through the mouth of the well bore and is on the surface of the land. If the gathering

[6] The American Gas Association defines compression as "[t]he action on a material which decreases its volume as the pressure to which it is subjected increases." Natural Gas Glossary, American Gas Association, www.aga.org.

[7] A compressor station is any permanent combination of facilities which supplies the energy to move gas at increased pressure from fields, in transmission lines, or into storage. Natural Gas Glossary, American Gas Association, http://www.agra.org.

[8] *Martin v. Glass*, 571 F. Supp. 1406, 1415 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984) (unpublished table opinion). *Cf. Clifton*, 325 S.W.2d at 690-91 (the term "produced" means "produced in paying quantities" which means that the well pays a profit); *Pack v. Santa Fe Minerals*, 869 P.2d 323 (Okla. 1994)(term "produced" means capable of producing in paying quantities and does not include the marketing of the product).

lines were disconnected from the well bore and the well was opened, the natural gas would flow from the producing formation, through the mouth of the well bore and into the atmosphere. From that prospective, compression has nothing to do with a well producing natural gas or its ability to produce natural gas.

On the other hand, if the natural pressure of the gas stream coming from a well is insufficient for the gas stream to be injected into a transmission pipeline, the gas will either not be produced, or it will produce at a slower rate. From an engineering and physics perspective, a stream that flows at a lower rate of speed has difficulty merging into a stream flowing at a higher rate of speed. The faster flowing stream will cause back pressure on the slower flowing stream, prohibiting or inhibiting the slower stream from combining with the components from the faster flowing stream. In other words, a log jam occurs. Without compression increasing the pressure of the natural gas stream and, in effect breaking the log jam, the gas from the wells feeding that stream will not flow through the mouth of the well. Some have argued, consequently, that the break-up of the log jam makes compression a production, not a post-production, operation because gas is not produced until it is "severed from the land."[9]

Why is the distinction important? It is clear that all natural gas production costs, i.e. those associated with exploring for, developing, and bringing gas to the mouth of the well, are borne by the producer alone.[10] Under Texas law, absent lease language to the contrary, royalties are subject, though, to their proportionate share of the costs incurred after production, including

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[9] *Id*.

[10] *Heritage Res., Inc.*, 939 S.W.2d at 121-22.

costs associated with compression.[11] Under the law of Oklahoma, Kansas, Colorado and certain other states, royalties are also subject to post-production compression costs under certain circumstances to be discussed below.[12] So, the question to be answered is when is the gas severed from the land?

There are only two reported opinions on this point, one of which has been heavily relied upon by Texas courts, including the Texas Supreme Court – *Martin v. Glass*.[13] In *Martin*, the producer drilled two wells that produced gas under their own pressure into a nearby line.[14] The wellhead pressure, though, was insufficient for the gas to flow into the marketing pipeline and the gas had to be flared or the wells shut-in.[15] To avoid this loss, the producer added compression on the lease so that the gas from the wells could be taken to market.[16] The producer gathered the gas, compressed it and transmitted it into the buyer's pipeline.[17] From the facts of the case, it is clear that without compression being added to the surface gathering lines, the wells would not have produced natural gas that could be taken to a market.

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[11] *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 135 (Tex. 1996); *Heritage Res., Inc.*, 939 S.W.2d at 121-22; *Parker v. TXO Prod. Corp.*, 716 S.W.2d 644, 648 (Tex. App.-Corpus Christi 1986, no writ).

[12] *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203, 1210 (Okla. 1998); *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 800 (1995); *Garman v. Conoco, Inc.*, 886 P.2d 661 (Colo. 1994).

[13] 571 F. Supp. 1406 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984) (unpublished table opinion). Relied upon in *Judice*, 939 S.W.2d at 136; *Heritage Res., Inc.*, 939 S.W.2d at 122-23; *Parker*, 716 S.W.2d at 648.

[14] 571 F. Supp. at 1409.

[15] *Id.*

[16] *Id.*

[17] *Id.*

After concluding that post-production costs could be properly deducted from the royalty share,[18] the Court analyzed whether the compression operation was production or post-production. Recognizing that gas is produced when it is severed from the land,[19] the *Martin* Court stated as follows:

> [t]he facts established that "production" of gas had been obtained from two wells on the Glass-Martin lease. (There was sufficient pressure to bring the gas to the wellhead or mouth of the well).[20]

Accordingly, since there was sufficient pressure in the well bore to bring the gas to the mouth of the well, the gas was severed. According to the *Martin* opinion, any compression that was designed to move the gas from the well and down the pipeline at higher pressure was not a production operation, but was a post-production activity.[21]

The second case to address whether compression is a production or post-production cost is *Parker v. TXO Production Corp.*.[22] In *Parker*, TXO had drilled two wells.[23] Both wells produced successfully for several years.[24] Eventually, compression was added by the gas purchaser to increase the pressure in the gas stream to better deliver the gas into the buyer's

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[18] The Court made this determination based upon the location where royalties were to be determined which, under the express terms of the lease, was at the wellhead. *Id*. at 1411. Since value was to be based upon that location, any marketing or transportation activities downstream from the wellhead had to be paid on a prorate basis by both the working interest and royalty interest owners because the producer was transporting the lessor's share of the gas. *Id*. at 1411-12.

[19] *Id*. at 1415 (citing *Lone Star Gas Co. v. Murchinson*, 353 S.W.2d 870 (Tex. Civ. App.-Dallas 1962, writ ref'd n.r.e.)).

[20] *Id*.

[21] *Id*.

[22] 716 S.W.2d 644 (Tex. App.-Corpus Christi 1986, no writ).

[23] *Id*. at 645.

[24] *Id.*

pipeline.[25] TXO also compressed the gas at the wellsite in order to, as testified by the TXO engineer, "increase production from the wells."[26] TXO then deducted the cost of its compression from the lessor's royalties.[27] The facts do not reveal when the TXO wellsite compressor was installed. Additionally, there are no facts stated in the opinion concerning whether the reservoir had sufficient pressure to move the gas to the mouth of the well prior to being compressed.

The *Parker* court recognized that the law stated in *Martin v. Glass* was correct, i.e. if there is sufficient pressure in the well to bring the gas to the mouth of the well, compression to assist in delivering the gas to the buyer was a post-production operation.[28] Though recognizing that the *Martin* court was correct, the court in *Parker* then held that *Martin* was distinguishable from the facts before it.[29] Relying upon the testimony from TXO's engineer that the compression was added to increase production from the wells, the court ruled that the compression was a production cost and, thus, not deductible from the lessor's royalties.[30]

The *Parker* case is perplexing. While it acknowledges the correctness of *Martin*, it chooses to ignore the facts upon which the *Martin* case was decided in order to reach a desired outcome. In *Martin*, there would not have been <u>any</u> production but for the compression. Still the compression was post-production because the gas came to the mouth of the well under its own pressure. In *Parker*, compression was added to <u>increase</u> production. Logically, the outcome in

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[25] *Id*.

[26] *Id.* at 648.

[27] *Id.*

[28] *Id*.

[29] *Id*.

[30] *Id.*

Parker should have been the same as in *Martin*. The result in *Parker* is illogical because all post-production activities, whether they be compression, treating, dehydrating, adding pipeline capacity or otherwise, have the result of increasing production because they prepare the gas for, or move it to, the market. Without them, little or no gas would be produced because it could not be sold.

Based upon the reliance on *Martin* by the court in *Parker*, one can conclude that if the testimony had been that the TXO wells had sufficient pressure to bring the gas to the mouth of the well and compression was added to increase line pressure which resulted in more production from the wells, the result in both cases would have been the same. Unfortunately, such was not the testimony and it appears that the cases are irreconcilable. Having said that, the ruling in *Martin* is the more logical and reliable of the two cases. This is bolstered by the fact that the Texas Supreme Court has cited to, and relied upon, *Martin*, rather than *Parker*, in no less than two loadstar cases concerning the proper payment of royalties after taking into consideration deductions for post-production costs – *Heritage Resources, Inc. v. NationsBank* and *Judice v. Mewbourne Oil Co*.[31]

In summary, in Texas if the well will produce under its own pressure, compression is a post-production operation. Such is the law, even though it adds the benefit of increasing production from the well because it removes the log jam described above. As a post-production activity, under Texas law the lessor's share of the reasonable cost of compression is properly

[31] *Judice*, 939 S.W.2d at 136; *Heritage Res., Inc.*, 939 S.W.2d at 122-23

deductible from his/her royalties.[32] Under the law of Oklahoma, Colorado and Kansas, however, more analysis is required under the marketable condition rule.

Is compression affected by the "marketable condition rule"?

One question the reader may ask is whether or not compressing gas is "marketing" when it deals more with transportation. The answer to this question depends upon the breadth of the word "marketing." A broad definition of marketing is the sale of production and the steps necessary to complete the transaction. By using this wide view, compression is clearly a marketing function, as would be all other activities until the gas reached the burner of the ultimate consumer. A more limited definition would be that marketing is the preparation of the gas by eliminating impurities and the negotiation of a sales contract. This more constrained view eliminates the transportation of gas from the field to the consumer and all related endeavors, including compression, from marketing.

Why is the distinction important? Under Texas law, it is of no importance. Unless there is lease language to the contrary, a royalty owner must pay her/his proportionate share of all post-production costs.[33] Under the law of other states, though, such costs are not deductible from royalties until the producer has prepared the gas for market, i.e. has placed it in a marketable condition.[34] After creating a marketable product, expenses for treating, compressing or

[32] *Heritage Res., Inc.*, 939 S.W.2d at 122.

[33] *Id*.

[34] *Mittelstaedt*, 954 P.2d at 1206; *Sternberger*, 894 P.2d at 800; *Garman*, 886 P.2d at 660.

transporting the gas are properly deductible.[35] Due to its proximity to the state of Texas, this article will focus upon Oklahoma to illustrate this view.

In a somewhat controversial decision, the Oklahoma Supreme Court held in *Mittelstaedt v. Santa Fe Minerals, Inc*., that a producer has a duty to provide a marketable product available to market at the wellhead or on the leased premises.[36] Oklahoma believes that such a duty is part of either the lessee's production obligations, or its duty to market production after severance. In which area of oil and gas jurisprudence this obligation falls under Oklahoma law is unclear. What is clear, though, is that in Oklahoma compressing low pressure gas on the leased premises for injection into a higher pressure pipeline is a part of the producer's duty to provide a marketable product.[37] As such, the costs associated with compression until the product is marketable are not shared by royalty owners.[38] After the gas is "marketable," compression that occurs off of the leased premises may be deductible from royalties if the lessee can show that the compression enhanced the value of an already marketable product and increased royalties.[39] The analytical rules set forth in *Mittelstaedt* are also used in Kansas and Colorado.[40]

Unlike Texas law, the Oklahoma view creates uncertainty and is fertile ground for litigation. Whether a post-production charge for compression against a royalty owner is

[35] *Id*.

[36] *Mittelstaedt*, 954 P.2d at 1208

[37] *Mittelstaedt*, 954 P.2d at 1209; *Wood v. TXO Prod. Corp*., 854 P.2d 880, 882-83 (Okla. 1992).

[38] *Id.*

[39] *Mittelstaedt*, 954 P.2d at 1210.

[40] *Sternberger*, 894 P.2d at 800; *Garman*, 886 P.2d at 660

allowable is an individual case by case analysis.[41] That means a court must review several facts. Where did the compression occur – on the leased premises or off? If the compression was on the lease, it is not deductible. If the compression occurs off of the leased premises, the court must then determine whether gas was in a "marketable" condition prior its compression. If so, did the compression change the constituents of the gas?[42] Additionally, if all of the above is true, did the compression enhance the value of the gas?[43] The problem with the complicated Oklahoma marketable condition rule is that it ignores certain key realities.

The first reality is that all natural gas is a marketable product at the well. Regardless of its condition or pressure status, all natural gas has a value at the wellhead and may be sold at the wellhead. For many years, natural gas was sold at the well to pipeline companies. The pipeline companies would gather the gas, treat it, process it, compress it and transport it.[44] Typically, the purchase price paid by these companies was a set price minus the cost for these activities. Royalties were then paid based upon the actual amount received from the pipeline company. Though pipeline companies are no longer wellhead buyers of gas,[45] there are third party purchasers of natural gas at the wellhead. Non-producing middle market companies and pure marketing companies purchase wellhead volumes and then perform these services. Additionally,

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[41] *Mittelstaedt*, 954 P.2d at 1208.

[42] *Id*. at 1210.

[43] *Id*.

[44] James Hardwick and J. Kevin Hayes, *Gas Royalty Issues Arising from Direct Gas Marketing*, Oil & Gas Law & Taxation, § 11.02 (1991).

[45] Pipeline companies ceased such activities primarily in response to FERC orders 380, 436 and 500. *See generally, Wisconsin Gas Co. v. FERC*, 770 F.2d 1144, 1149 (D.C. Cir. 1985); *Associated Gas Distributors v. FERC*, 824 F.2d 981, 994 (D.C. Cir. 1987).

some producers, or their affiliates, also purchase wellhead gas from third parties.[46] The price paid by these buyers will be a market price minus the cost for these services. The point is that all natural gas is marketable regardless of its condition. To require a producer to conduct operations to place the gas in the condition the court *deems* marketable, is a questionable use of judicial power.

The second reality is that the marketable condition rule seems to ignore the clear language the parties chose to use in their lease as to where and how royalties are to be valued. Under the marketable condition rule, regardless of all other language used by the parties in their agreement, the lease must specify that deductions for compression and other post-production activities may be made by the lessee.[47] Oklahoma believes that the implied covenant to market requires the producer to create a marketable product, and that the implied covenant trumps, or modifies, the express language in the lease.[48]

The question that should be asked is whether the parties had already agreed to post-production deductions based upon the clear and unambiguous language they agreed upon. Most oil and gas leases place the point of royalty determination at the "mouth of the well" or at the "wellhead." Based upon the custom and usage in the industry, which Oklahoma recognizes is used in interpreting contracts,[49] the terms "mouth of the well" and "wellhead" have distinct and clear meanings. The "mouth of the well" or "wellhead" is the location where the gas exits the

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[46] *See Howell v. Texaco, Inc*., 112 P.3d 1154 (Okla. 2004).

[47] *Mittelstaedt*, 954 P.2d at 1207; *Garman*, 886 P.2d at 660; *Wood*, 854 P.2d at 883.

[48] *Wood*, 894 P.2d at 882-83.

[49] *Mittelstaedt*, 954 P.2d at 1208.

earth.[50] Consequently, by placing the point of valuation at that location, the parties have established the type of commodity for which royalties shall be paid – raw natural gas in its natural state. As a result, any post-production activity, including compression, enhances the value of the gas and the lessor should share in this expense.

Furthermore, many leases, if not most, set a clear and objective methodology for the determination of the value to be paid to the lessor. The most commonly used valuation method is "market value of the gas." The term "market value" is an express clause that has a clear and unambiguous meaning. It means the value a willing buyer will pay to a willing seller when neither is obligated to buy or sell.[51] Consequently, many leases require that royalties be based upon the market value of the gas at the wellhead. Again, the agreed upon language sets a location, which is prior to any post-production operations, and a method of valuation, i.e. what would a willing buyer pay to a willing seller for natural gas in the existing conditions as it exits the wellhead. When a court supplements this clear and unambiguous language with a covenant to render the gas in a marketable condition, it is changing the intent of the parties which is improper.[52]

The third reality is that the working interest owner bears most of the cost and risk anyway. The marketable condition rule is based upon mistrust when there is no need for it. As stated in *Mittelstaedt*, the rationale for the marketable condition rule is that:

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[50] *See e.g.*, *Petron Dev. Co. v. Washington County Bd. of Equalization*, 91 P.3d 408 (Colo. Ct. App. 2003), *aff'd*. 109 P.3d 146 (Colo. 2005).

[51] *Howell*, 112 P.3d at 1159.

[52] *HECI Exploration v. Neel*, 982 S.W.2d 881, 888 (Tex. 1998).

> . . . nonworking interest owners (royalty owners) have no input into the cost-bearing decisions. (citation omitted). These owners have no input on the marketing decisions. If costs were imposed on royalty owners they would be 'sharing the burdens of working interest owners without the attendant rights.' (citation omitted).[53]

Since royalty owners have no input, they should not be burdened with the cost regardless of the lease language. This reasoning ignores one very important point concerning an oil and gas lease. The largest share of the costs associated with post-production operations is suffered by the lessee or producer. The royalty share is normally less than twenty percent. It comes to reason that the working interest share of eighty percent will be motivated to keep the costs as low as possible. Additionally, the royalty owner already has a check on the amount of costs to be charged. As will be discussed below, only "reasonable" costs may be allocated to the royalty owner.[54] It follows, then, that the royalty owner does have input into the cost making decision.

In summation, if a producer is operating wells in Oklahoma, Colorado, Kansas or other states, she/he will have to contend with the marketable condition rule. Despite the fact that the lease language controls the intent of the parties, these states have read a different intent into the oil and gas lease. One factor these courts didn't consider, however, is that by not allowing a deduction for compression, depending upon the price of natural gas, some wells may not be produced at all. Moreover, Oklahoma could have, and should have, excluded compression and transportation from the marketable condition rule. Neither operation have anything to do with making the gas marketable by eliminating impurities from the stream. Such a separation in the

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[53] *Mittelstaedt*, 954 P.2d at 1207.

[54] *Id*. at 1209.

definition of marketing is more logical than lumping all of these operations under the rule and forcing the fact intensive inquiry described above.[55]

If the cost of compression is deductible, how much is allowable?

There is not an opinion, at least in Texas, that answers this question as a matter of law. The only guidance available from the judiciary is that the cost must be "reasonable."[56] The question of reasonableness is more hotly debated when it is the producer, as opposed to a third party, that is providing the compression services. Lessors believe that the producer's reasonable costs are limited to the actual costs of operating the compressors and nothing more. Producers feel that operational costs are one of many factors.

An important question that all concerned persons should ask is what is the universe of costs associated with compression? A non-inclusive list of costs are:

1. Cost of the compressor;

2. Cost of installation and hook-up;

3. Cost of parts and maintenance;

4. Human hours associated with maintenance and operation; and

[55] In *Johnson v. Jernigan*, 475 P.2d 396 (Okla. 1970), the Oklahoma Supreme Court held that off-lease transportation was deductible from the royalty share based upon the language used in the lease concerning where and royalties were to be determined. *Id*. at 398-99. In *Wood*, the court was asked to expand this rule to transportation, and specifically compression, that was on the leased premises. 854 P.2d at 881. The court limited its ruling in *Johnson* to off the leased premises operations based on the marketable condition rule without providing a rational basis for the distinction except to imply that the distance to the market was a deciding factor. *Id*. at 882.

[56] *Le Cuno Oil Co. v. Smith*, 306 S.W.2d 190, 195 (Tex. Civ. App.-Texarkana 1957, writ ref'd n.r.e.).

5. Fuel.[57]

Some of these broad categories may be classified as capital costs by the producer. Royalty owners assert that capital costs should never be forced upon the royalty share. According to the lessor's perspective, the physical compressors are assets of the producers. They questioned why they should be burdened with the repayment of its share of this expense, when she/he does not own the asset, nor receives the tax benefit of depreciating that asset over time? From the working interest perspective, capital costs are real and necessary expenses for the addition of compression to a gas stream and, as such, are proportionately deductible from the royalty share. Additionally, lessees believe that they should be entitled to a reasonable return on their capital investment and should be allowed to charge a profit to the royalty owner.

The issue is, was the cost charged to the royalty share "reasonable." The question of "reasonableness" must resolved by a fact finder on a case by case basis.[58] There is no magic formula to cure this dispute. Some guidance, however, is available.

Since the legal question over deductibility centers around the language in the royalty clause in the lease, the standard concerning the amount of allowable costs should also be found in the royalty clause of the lease. There are generally two types of royalty clauses, market value and proceeds of sale. Market value is measured by comparable sales of like kind and quantity of gas.[59] Under a proceeds clause, royalties should be paid based upon the best price reasonably

[57] The author is aware that this list is very broad and that there may be many additional items to add or to delete. It is not intended to be limited to the enumerated items but is for illustrative purposes only.

[58] *E.g. State Farm County Mut. Ins. Co. v. Plunk*, 491 S.W.2d 728, 731 (Tex. Civ. App.-Dallas 1973, no writ).

[59] *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 372-74 (Tex. 2001); *Heritage Res., Inc.*, 939 S.W.2d at 122.

obtainable.[60] Though similar, these two terms are not the same when it concerns the base value upon which royalties should be paid.[61] It is suggested here that the amount of deductions should be upon the same standard as set forth in the lease, either market value or the best price reasonably obtainable. In this area, though, the terms may be a distinction without a difference.

A good measure for the reasonableness of post-production deductions, regardless of the language in the royalty clause, is what is the amount paid by other producers for the same service in the same, or a similar, field? If the producer, or one of its affiliates, is supplying the compression, the court and jury should review the prices charged by independent third party compression companies. Though not dispositive, if the producer's charge is within the band between the highest and lowest prices charged by independent third parties, it is within the range of reasonableness. If the producer was not providing the compression, the price charged by the third party is the one that would be levied against the royalty share. If the two prices are similar, then there is no difference suffered by the lessor.

Likewise, if the producer, or one of its affiliates, is providing compression services to other producers; the prices agreed upon in those transactions are evidence of reasonableness. The non-affiliated producer is motivated to negotiate the best price it can for compression services since it bears the largest portion of this expense. Since it is so motivated, the non-affiliated producer will not normally agree to a price that is above the market range for this service. While this argument is persuasive, another factor to consider is the availability of

[60] *Amoco Prod. Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280, 285 (Tex. Civ. App.-El Paso 1979), *aff'd per curiam*, 611 S.W.2d 610 (Tex. 1980).

[61] *Yzaguirre*, 53 S.W.3d at 372-74.

competitive compression services in the field. If the competition is limited or non-existent, the lessee may have to further justify its charge by explaining how it determined the price and that the price is in accordance with industry standards. Another response from the lessee, and a check against it being unreasonable, is that if its price was too high, the non-affiliated producer would provide its own compression services, if it could do so at a cheaper price.

Does the above discussion also mean that if a third party is providing the compression services that the question of reasonableness is answered as a matter of law? The answer is "no." If the basis for royalty payments is "market value," the third party charges must be equal to or less than the range of comparable charges in the field. As for royalties based upon the proceeds from the sale of production, the producer needs to seek and obtain the lowest third party compression charge reasonably available in the field for like services. The rationale for this position is that under the implied covenant to reasonably market, which applies to proceeds royalty clauses but not to market value clauses,[62] the lessee must pay royalties based upon the highest price reasonably obtainable. In order to achieve that goal, the lessee should also be seeking the lowest deductible costs reasonably obtainable considering the services to be provided.

The answer to the question of how much can be deducted from the royalty share has to be determined on a case by case basis. The relevant factors to consider include the lease, the availability of compression facilities in the area, the amount of gas to be compressed and many

[62] *Union Pac. Res. Group, Inc. v. Hankins*, 111 S.W.3d 69, 71-72 (Tex. 2003); *Yzaguirre*, 53 S.W.3d at 372-74; *Union Pac. Res. Group, Inc. v. Neinast*, 67 S.W.3d 275, 282-83 (Tex. App.-Houston [1st Dist.] 2001, no pet.); *First Baptist Church of Pyote*, 579 S.W.2d at 285.

others. As stated above, since compressors use natural gas as fuel, the amount of the deductions for this service can be very expensive and hotly contested.

Conclusion

At the beginning of this article, the author asked the reader keep in mind that a royalty interest is "the landowner's *share of production*, free of the expenses of production."[63] The entire analysis concerning post-production costs and who bears the expense is dependent upon when is production complete and the nature of the interest owned by the royalty owner after severance. When production is complete is a matter of reviewing the oil and gas lease, which is a contract and is construed as such.[64] The intent of the parties to an agreement should be determined from the language they placed in their agreement. Once the parties have agreed upon the location of valuation of the lessor's compensation, all marketing, transportation and sales activities by the producer from that point on include the landowner's "share of production." As a result, all expenses from the point of valuation until sale should rightly be shared proportionately by the lessee and the royalty owner

[63] *E.g. Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 121-22 (Tex. 1996).

[64] *See Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 121 (Tex. 1996)(contractual construction rules used to interpret oil and gas lease); *Hitzelberger v. Samedan Oil Corp.*, 948 S.W.2d 497, 503 (Tex. App. – Waco 1997, pet. ref'd)("oil and gas lease is a contract and must be interpreted as a contract").