Analysis of the Propriety of Deducting Post-Production Gathering Costs, **Including Depreciation Expenses, from Royalty Owners' Shares**

The very definition of a royalty is a share of production free of the costs of production. But under a traditional "market value at the well" or "proceeds" royalty clause, royalty is valued at the well by "working back" from downstream sales. A mineral lessee accomplishes this valuation by deducting postproduction costs from the downstream sales price. The rationale is that costs subsequent to production generally increase the value of the product and must be "worked back" or "netted back" from the downstream sales price to obtain the true value at the well. Under this approach, a mineral lessee with a "market value at the well" or "proceeds" royalty clause may deduct the reasonable costs to transport the product from the well to a pipeline and to tap into that pipeline.[1]

If there is no current "market at the well" or if the system will result in a net benefit to the royalty owners, even assuming a current market at the well, the royalty owners may be charged the costs of the installation and operation of the new gathering system, to the extent it is located off of the leased premises. The geographical dichotomy between onsite gathering and offsite gathering arises because, typically onsite gathering is an operation necessarily linked to production,[2] and, thus, deductions for the costs and

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[1] Whether Louisiana continues to follow this as a bright line approach, as it did in *Merritt v. Southwestern Elec. Power Co.*, 499 So.2d 210 (La. App. 2d Cir. 1986), after the Supreme Court's decision in *Frey v. Amoco Production Company*, 603 So.2d 166 (La. 1992), is discussed *infra at* notes 6, 8 and 9 and associated text. Louisiana long ago recognized the viability of the net back method of calculating market value at the well, in the absence of comparable sales or other *indicia* of market value. *See Wall v. Public Gas Service Co.*, 178 La. 908, 152 So. 561 (1934) discussed *supra* at note 3 and *infra* at note 8.

[2] As discussed, *infra*, with regard to the JOAs, onsite operations are contemplated by and governed by the JOA. The JOA allocates the costs and expenses of onsite operations among the working interest owners. And, crucially, the JOA expressly recites that it governs production activities on the premises. The inference is that operation activities on the premises necessarily are, as reflected in the parties' agreement in the JOA, production activities. *But see Merritt v. Southwestern Electric Power Company*, 499 So.2d 210 (La.App. 2 Cir. 1986). *Merritt* involved gas produced from a well and transported via gathering lines to an existing pipeline. However, due to low flow pressure from the well into the gathering system, the lessee had to install compressors in order to get the gas to the pipeline. The court reasoned that there was no market or purchaser for the gas as it existed at the wellhead due to its low pressure, thus, there was no market at the well. To be marketed, the gas had to be compressed. Relying on *Martin v. Glass*, 736 F.2d 1524 (5th Cir. 1984)(Texas law applied and post-production costs found deductible), the court employed the reconstruction approach to the market value "at the mouth of the well," and held that the compression costs properly were deductible from the royalty owners' share. It is not clear from the opinion whether the gathering costs, other than compression, also were deducted.

Merritt appeared to have established a bright line test that post-production costs, including compression and all transportation costs, are deductible from the royalty owners' share, lending support to the notion that gathering costs necessarily are deductible from the royalty owner's share. It is doubtful that *Merritt* remains viable as a bright line test, if it ever actually was one, in light of *Frey* and *Merritt*'s dubious reading of the implied obligation to market. Moreover, *Merritt* relied on *Martin v. Glass*, which interpreted Texas law. And, Texas follows the *Vela* doctrine, named after *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866 (Tex. 1968), but, the Louisiana Supreme Court rejected *Vela* in favor of the *Tara* doctrine, named after *Tara Petroleum Company v. Hughey*, 630 P.2d 1269 (Okla. 1981)(mutual benefits analysis used to determine calculation of market value). *See Henry v. Ballard & Cordell Corp.*, 418 So.2d 1334 (La. 1982)(adopting *Tara* and rejecting *Vela*). *Merritt* briefly noted the implied obligation to market imposed on lessees, but interpreted it to mean that "[s]ince marketing the minerals benefits both the lessee and the expenses of the onsite gathering system would be improper. However, offsite-gathering/transportation costs may be deducted. Gathering the produced gas from the leased premises for transportation to a higher priced market than currently is available in the Gas Fields is a value-enhancing activity that serves the mutual cooperative benefits of both lessor and lessee discussed in *Frey*. Thus, installation costs of the offsite gathering system, including capital costs and depreciation, may be deducted from the royalty owners' shares. The geographical dichotomy between onsite and offsite operations, however, is not necessarily a bright line analysis that operates to foreclose a lessee from recovering onsite gathering costs. The system should be viewed as a whole to determine its design and functional purpose. If its purpose is to collect produced gas to pool for subsequent transportation to an offsite higher priced market, less weight (and perhaps no weight) should be given to the onsite/offsite distinction.[3] In all events, because Louisiana law limits the lessee to its fractional share set by the mineral lease in terms of gross proceeds, A Lessee may not deduct a profit allowance for the onsite or offsite gathering facilities from the royalty owners' shares.

As to how these capital costs should be deducted from a mineral lessor's royalty, they are commonly amortized over a period of time, such as the shorter of the expected life of the equipment or well or field. The risk of amortizing over too long a period of time is borne by the lessee because he has no means of recovering costs out of the lessor's royalty if the well depletes or reaches its economic limit before the three-year or other amortization period is reached.

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royalty owner, the royalty owner should bear a proportionate share of the marketing costs." *Merritt*, 499 So.2d at 214. This statement is of doubtful precedential value because the lessee also is subject to the implied duty to produce gas, yet the lessee is not entitled to share production costs with the lessor. *Merritt* also was decided under different industry circumstances than exist now. Moreover, as explained by other jurisdictions that rely on the implied duty to market to preclude allocation to royalty owners of post-production costs incurred to market the gas, imposing such costs against royalty owners renders them indistinguishable from working interest owners, who, unlike royalty owners, have a say in the costs incurred. *See, e.g., Fox Wood III v. TXO Production Corp.*, 854 P.2d 880, 882-83 (Okla. 1992)(court reviewed myriad of cases and held lessee bears compression, transportation, gathering and dehydration costs, i.e., costs incurred until gas is fit to enter pipeline finding that lessee's duty to market includes the cost of preparing the gas for market apropos the fact that "the mineral owner's decision whether to lease or to become a working interest owner is based upon the costs involved. . . . [W]orking interest owners who share costs under an operating agreement have input into the cost-bearing decisions. The royalty owners have no such input after they have leased. In effect, royalty owners would be sharing the burdens of working interest ownership without the attendant rights").

[3] The onsite/offsite dichotomy is not necessarily a bright line that determines the point at which gathering costs may be deducted from the royalty owner's share, particularly where the system design is to facilitate field-wide pooling and enhanced market access. Instead of drawing a line at the lease border and segmenting a gathering system geographically as to costs that cannot be shared (on-site) versus those that can (off-site), a system-wide view may be more appropriate. In other words, the system's purpose should be evaluated as a whole. If its purpose is simply to gather production on lease, these costs probably should not be worked back to the royalty interest. However, if the system is designed to pool field-wide production to open up all leases to better market opportunities, even system costs associated with on-lease infrastructure may be allocated to the royalty interest. This "system-wide" analysis of the function of a gathering system was the approach used in *Sternberger v. Marathon Oil Company*, 894 P.2d 788 (Kan. 1995), discussed *infra* in text, where the court permitted cost deduction from the royalty share based on the system costs. Such an approach also folds neatly into the mutual benefits analysis applied in *Frey*.

B. Discussion

The Louisiana Supreme Court expressly has adopted an implied obligation to market approach to determining a royalty owner's share, which is to be applied in light of the economic and practical realities of the gas market, tempered by the facts and circumstances of the particular case and subject to a reasonableness test.[4] *Frey* articulated a benefits or bargained-for exchange test as follows:

> The lease represents a bargained-for exchange, with the benefits flowing directly from the leased premises to the lessee and the lessor, the latter via royalty. An economic benefit accruing from the leased land, generated solely by virtue of the lease, and which is not expressly negated, is to be shared between the lessor and lessee in the fractional division contemplated by the lease. [5]

Frey, 603 So.2d at 181 (citations omitted). *Frey* emphasized that, in the absence of an express clause to the contrary, the lessee will not be permitted to calculate royalty payments in such a manner that permits it to receive a greater part of the *gross* revenues than the fractional division stated in the mineral lease and if the lessee derives an economic benefit that accrues from the leased land, it will be shared in the fractional division set by the lease. *See Frey*, 603 So.2d at 174. Under *Frey*, therefore, A Lessee may deduct the project's costs from the royalty owner's share so long as A Lessee does not receive a larger fractional share of the gross revenues (*i.e.*, without deduction of gathering system costs) than the fractional divisions set by the mineral lease.

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[4] *Frey* is not a departure from previous Louisiana jurisprudence; Louisiana consistently has considered the practical and economic realities and the implied obligation to market as crucial factors that underlay the determination of royalty payments. *See Henry*, 418 So.2d 1334 (court relied on the implied obligation to market and the economic reality at the time that the long term gas contract was reasonable when executed, thus, the lessor could not recover royalties based on the subsequent increases in the spot market and the court held that "market value" meant the price the lessee obtained under a long-term gas sales contract); *Shell Oil Company v. Williams, Inc.*, 428 So.2d 798 (La. 1983) (relying on implied duty to secure market for produced gas, court found that the long term gas contract previously entered into by lessee was reasonable and lessor not entitled to royalties based on subsequent higher spot market value).

As early as 1934, the Louisiana Supreme Court, without articulating the implied duty to market, nonetheless considered economic realities in determining the proper method to calculate the royalty share. *Wall v. Public Gas Service Co.*, 178 La. 908, 152 So. 561 (1934). The court found that because a market existed at the well, calculated based on the prices paid at several fields in the area already serviced by existing pipelines and various companies competitively bid and bought gas directly from the fields, the court held that the royalty share was due based on that market, although the lessee received a higher price after transporting the gas two miles off of the leased premises. The lessee was not required to pay the royalty owner based on the higher price less transportation expenses, although that net price exceeded the comparable sales market value. In so ruling, the court noted in *dicta*, without expressly discussing implied duty to market, that were there no market at the well and gas had to be transported the two miles to be sold, lessee would be entitled to deduct reasonable transportation costs from royalty owner's share.

[5] "[T]he process reflects our appreciation of the cooperative nature of the lease arrangement as well as an understanding of the economic an practical considerations underlying the royalty clause. Retention by Amoco of the entire take-or-pay payment would permit Amoco to receive a part of the gross revenues from the property greater than the fractional division contemplated by the Lease." Such a result can not be countenanced by this Court." *Frey*, 603 So.2d at 174 (citation and internal quotations omitted).

Frey would not permit a deduction against the royalty owners' shares for a profit margin. The court held that the lessee would not be permitted to calculate royalty payments so that it receives a greater part of the *gross* revenues than its fractional division under the lease. *See Frey*, 603 So.2d at 174. The court held that the royalty owners were due their royalty owner share on the settlement of take-or-pay litigation between the lessee and the purchasing pipeline. The subsequent history of *Frey* further weighs against any profit margin deduction against the royalty owners' shares. After receiving answers to the questions it certified to the Louisiana Supreme Court, the Fifth Circuit remanded the matter to the district court for it to determine the actual share of the take or pay settlement due the royalty owners. The district court, relying on the *gross* revenues language in *Frey*, refused to deduct from the royalty owners' share the costs incurred by the lessee in "'implementing, monitoring and negotiating recoupment volumes and payments,'" and refused to deduct any portion of the" legal and extra-legal costs thereof," and held that the royalty owners were due their fractional shares calculated based on the *gross* settlement amount. *Frey v. Amoco Production Co.*, 1994 WL 202330, *4 (E.D.La. 1994).

An aggressive mineral lessor may rely on the *gross* revenues language of *Frey* and the district court's ruling after certification and remand to contend that no deduction, even for capital and operating expenses of the offsite gathering system, may be made against its share, by arguing that such expenses are analogous to the implementation costs that the lessee attempted to deduct against the royalty share in *Frey*. The aggressive mineral lessor may argue that it is simply entitled to its fractional share of the gross revenues at the higher market price. However, such an argument would ignore the fact that currently there is a market at the well, *i.e.*, the produced gas is being sold at some price, and that *Frey* approved a mutual benefits, value enhancing approach to whether certain post-production expenses are deductible. *See also Wall, cited supra* at notes 3, 5, and 8. Moreover, the take or pay settlement was found to set the market price at the well, thus, the costs the lessee sought to deduct were in the nature of production, not post-production, costs. *See Frey*, 1994 WL 202330 at *4 (finding the settlement was the amount realized at the wellhead).

While no Louisiana case was located that discussed whether a lessee could deduct capital costs and depreciation expenses of gathering systems installed to collect product for transportation to a higher priced offsite market from the royalty owners' shares, there is well-reasoned authority from several jurisdictions that support such deductions, including cases applying Colorado law,[6] which typically is viewed as being more royalty owner favorable. These cases applied a *Frey*-type of mutual benefits or value enhancing analyses, and concluded that capital costs and depreciation expenses may be deducted from a royalty owner's share, if the royalty owner receives a benefit or there is value added to the product. *See, e.g., Creson v. Amoco Production Company*, 10 P.3d 853 (N.M. App. 2000)(in a thorough opinion collecting cases from a myriad of jurisdictions, court permitted deduction of post production costs of gathering system used to collect the product and transport it to an offsite market although there was a market at the well and

[6] *See Rogers v. Westerman Farm Co.*, 986 P.2d 967 (Colo. Ct. App. 1998) and *Garman v. Conoco, Inc.*, 886 P.2d 652 (Colo.1994).

the system enhanced the value of the product, *i.e.*, it added value to the product that was passed onto the royalty owners); *Atlantic Richfield Company v. Farm Credit Bank of Wichita*, 226 F.3d 1138 (10th Cir. 2000)(applying Colorado law and discussing *Rogers* and *Garman*, court allowed deduction of costs of gathering system from royalty owners' shares that collected the product and transported it 200 miles downstream to an offsite market because no market existed at the well); *Sternberger v. Marathon Oil Company*, 894 P.2d 788 (Kan.1995)(applying Kansas law, and discussing Colorado, Texas and Oklahoma laws, court held that lessee could recover gathering line amortization expenses from royalty owner shares to recover a portion of transportation of the produced gas from the lease to offsite markets because there was no market at the well).[7] In these cases, the courts ruled that capital expenses, including costs of capital, depreciation on actual capital expenditures, including interest during construction, and operating expenses may be deducted from the royalty owners' share, subject to a reasonableness standard, *i.e.*, the reasonably prudent operator standard. A deduction for profit was not permitted.

The legal relationship between the mineral lessor and mineral lessee can become more tenuous once the mineral lessee has recovered its capital costs to construct the gathering line and tap. An aggressive mineral lessee may continue deducting costs from its mineral lessor's royalty on ground that the recovery of capital costs are not the issue. The issue is what is the mineral lessor entitled to, and the answer is that it is only entitled to be paid based on market value at the wellhead. If the gas is being sold downstream of the wellhead, then gathering fees must be worked back out of a downstream price to ascertain the true value at the wellhead. Some mineral lessees may even gather gas in the same gathering line from other leases for a fee. Pretty soon, the mineral lessee is profiting from its gathering line. Not only is it profiting from that gathering line, but also it owns many other gathering lines from which it is also generating revenue. This end result becomes problematical in light of *Frey's* seeming prohibition against the lessee profiting from the lessor. *See Frey*, 603 So.2d at 174.

On the other hand, an aggressive mineral lessor may argue that having paid for its share of the capital costs to build the gathering line and tap into the transmission line, it now owns an interest in the equipment. The retort is that the mineral lessor never paid its share of these capital costs; instead, it was paid its royalty share. That royalty share, however, did not have a market value at the well and thus had to be valued by taking into account postproduction costs.

C. Conclusion

Reasonableness and mutual benefit will determine the propriety of deducting the costs and expenses of the new gathering system from the royalty owners' shares. These determinants would not permit the lessee to profit from the lessors, thus, a profit margin

[7] *See also Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984)(permitting capital expense deductions because the post production processing and transportation of the product added value to the product). *Piney Woods*, however, facially is contrary to *Frey* as it suggests that the costs of making a produced product marketable are deductible from the royalty owner's share, somewhat contrary to the analysis employed by *Frey*.

may not be built into the royalty share deduction. However, these same determinants warrant a system-wide functional analysis to govern the deductibility of costs for both the onsite and offsite infrastructure. The onsite/offsite geographical dichotomy would be but a factor to consider. The lesser the degree that the gathering system is functioning as a typical local gathering facility and the greater the degree that the system is intended for use as a system-wide gathering facility designed to collect produced gas for transport to a higher priced offsite market, the more likely it is that geography will not foreclose deductions from the royalty share of system-wide costs.

While the royalty owners' consent is not required, consent would preemptively foreclose a subsequent challenge by a disgruntled royalty owner, which may arise simply because the lessor lacks sophistication or misreads *Frey* and its subsequent history or simply becomes greedy. The downside to negotiating the deduction up front with the royalty owners is the potential that the royalty owners may seek to increase their fractional share. However, if the demand is not excessive, its costs may outweigh its benefits, as it will eliminate the risk of a subsequent royalty owner lawsuit challenging the deductions.