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VIA FEDERAL EXPRESS

Mr. David S. Guzy
Chief, Rules and Publications Staff
U.S. Department of the Interior
Minerals Management Service
Royalty Management Program
P.O. Box 25165, MS3101
Building 85, Denver Federal Center, Room A-212
Denver, CO 80225-0165

Re: *Establishing Oil Value for Royalty Due on Federal Leases, 62 Fed. Reg. 183 at p. 46460 (September 22, 1997)*

Dear Mr. Guzy:

Texaco Inc., on behalf of itself and its affiliates Texaco Exploration and Production Inc. ("TEPI") and Texaco Trading and Transportation Inc. ("TTTI"), appreciates the opportunity to submit these comments in response to the September 22, 1997 Notice of Reopening the Public Comment Period pertaining to MMS' proposed crude oil valuation rule. We commend MMS' efforts to reevaluate its original proposed rule published on January 3, 1997. The overwhelming record evidence, presented in comments from virtually every sector of the industry, shows that the original proposal was seriously flawed. This evidence shows that, for both policy reasons and as a matter of law, royalties must be assessed on the value of crude oil in the production field, *i.e., at the lease,* and not some distant market center.

The record evidence shows, for example, that if royalties were based on values away from the lease, inefficiencies would displace rationale economic choices, both in terms of current activities and future investments. Both federal leases and federal statutes *require* royalties to be derived from values at the lease. Therefore, we believe that the alternatives listed in the September 22, 1997 Notice that would set values away from the lease, Alternatives 3, 4 and 5, reflect unsound economic policy, and would also be unlawful. Alternative 1, described as a "bid-out or tendering program," appears to be similar to Texaco's current tendering program, which was described in Texaco's earlier comments, and is discussed more fully herein. Alternative 2 describes a benchmark system, beginning with "[o]utright sales of like-quality crude in the field or area as described in Alternative 1." Alternatives 1 and 2 appear to recognize that royalties need to be derived from values at the lease. Alternatives 1 and 2 also appear to recognize, properly, that regardless of any other methodology, if crude oil is sold under an arm's-length contract at the lease, royalties should be based on the contract price. (The Notice appears unclear as to whether such arm's-length contract prices would continue to be used under Alternatives 3, 4 and 5.)

As set forth below, we do not believe that MMS should mandate the use of a tendering program because not all lessees may be capable of implementing that alternative. Therefore, some form of benchmark system that presents alternative lease-based valuation methodologies, including use of a tendering program, would be optimal.

A. Alternative 1 — Bid-Out or Tendering Program

This alternative appears to be similar to Texaco's tendering program, which was discussed in comments filed in response to MMS' initial proposed rule. Texaco's tendering methodology is based on bidding out representative volumes of crude oil in order to value similarly situated crude oil that is not sold arm's-length. Under the current tendering program, the first step is to categorize marketing areas into areas of comparable crude oil quality. Marketing areas are determined on the basis of type of oil (*e.g.*, sweet or sour) and transportation (*e.g.*, truck or pipeline) and are further categorized based on costs to common transportation points. The marketing areas generally correspond to specific geographic areas.

The volume of oil tendered ranges from approximately 12.5% to 20% of the volume available from a specified marketing area. Generally, the percentage tendered is at least equivalent to the royalty share of the oil. The tendered volumes do not come proportionally from each lease or from all leases in the marketing area, but instead are packaged so that significant quantities are available at a marketing area to attract competitive bids.

Invitations to bid are distributed to creditworthy third-party potential purchasers, the number of which varies. Most of the bidders are producers, refiners and/or marketers. Texaco affiliates are not permitted to submit bids under the program because it was felt that affiliate participation might discourage some bidders. The bid invitations specify individual leases, volumes, and transportation methods. Sales are made at the lease. The purchaser is responsible for transportation downstream from the lease. The bid forms specify a poster, the crude oil type, and deemed gravity and provides for the bidders' adjustment - plus or minus - to the price.[1] The term of the contract for accepted bids is six months, which is a fairly standard industry practice.

TTTI, Texaco's crude oil trading and transportation company, acts as TEPI's agent in administering the tendering process. TEPI solicits and receives the bids, evaluates the bids with assistance from TTTI, and sells to the highest bidder. On occasion, TTTI and TEPI have determined that the highest bid is insufficient. In such situations, TEPI sells to TTTI at a higher negotiated price. On other occasions, TTTI has determined that the highest bid price is overvalued and has declined to purchase the remaining volumes, in which case these volumes were offered to the bidder. TTTI has an option to purchase all or part of the remaining volumes at the tendered price. TTTI has exercised this option in virtually all cases. In the event that TTTI does not exercise this right, the remaining volumes are first offered to the highest bidder at the high bid price. If the high bidder does not purchase all of the remaining volume, such volumes are retendered.

TEPI pays royalty on the basis of the proceeds received from production tendered to third parties. For production sold to TTTI, the third party transactions are "normalized" to establish the price of affiliate sales. Normalization is the process by which TEPI utilizes the tendered price to adjust, if necessary, values of oil not sold to third parties within the marketing area. Adjustments are based primarily on location differences and certain quality differences. Adjustments generally are not made for gravity since the bid request requires the crude to be deemed. In the normalization process, TEPI uses certain known "market reference points" in adjusting for location. Leases with a common crude oil delivery station generally will have the same price. The process can also result in a higher or lower price for volumes not actually tendered depending on the distance from the lease to the common delivery point.

The tendering program is intended to establish the most accurate value possible at the lease, taking into consideration all relevant economic factors. It clearly provides a proper means for valuing production for royalty purposes, since the value assigned to the production reflects the price received in actual arm's-length transactions at the lease in the relevant marketing area. This is particularly important because each marketing area has unique characteristics. Crude oil fields are subject to widely divergent economic influences depending on such factors as the quality of the crude, the supply and demand for different types of crude and the capabilities of local refiners in each region, the distance from the field to potential buyers, and the transportation alternatives available from each field. (*See* Report of Dr. Benjamin Klein, attached to our May 28, 1997 comments, at p. 5.) Furthermore, by tendering an amount at least as great as the royalty share, Texaco ensures that royalty owners receive at least what they

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[1] Initially, TEPI did not specify a poster in the bid solicitation materials. It now specifies a poster in an effort to simplify the analysis and normalization of the bids.

would have received had they taken their royalty barrels in kind from the marketing area.

A tendering program of the type employed by Texaco should be permissive. Although tendering is clearly effective in setting a fair value for crude in the producing field, not every company would be capable of implementing an effective tendering program. Some companies may lack the investment, personnel and expertise to conduct this type of program. Some companies may have legal obligations or operational needs such that the tendering of barrels might result in liability or economic hardship. However, we strongly urge that those companies willing and able to sell a representative share of production should be accorded the full recognition that a fair royalty value is established by these arm's-length sales at the lease.

B. Alternative 2 — Benchmarks

Alternative 2 uses five separate benchmarks, and our comments are directed to each of them as follows:

1. Outright Sales of Like-Quality Crude in the Field or Area as Described in Alternative 1.

See comments to Alternative 1 above.

2. The Lessee's or its Affiliate's Arm's-Length Purchases from Producers at the Lease in the Field or Area.

As with the arm's-length sales described in Alternative 1, a lessee's or its affiliate's arm's-length purchases in the field or area are equally valid indicators of fair market value at the lease. Texaco reiterates its earlier comments that valuation of production for royalty purposes, whether derived from the lessee's sales or the lessee's purchases, must be based on values at the lease. The statutory basis for the collection of royalties is contained in the Minerals Leasing Act of 1920 and the Outer Continental Shelf (OCS) Lands Act. The Minerals Leasing Act gives the Secretary authority to lease public lands, and requires that any such "lease shall be conditioned upon the payment of a royalty at a rate not less than 12.5 percent in *amount or value of the production removed or sold from the lease.*" 30 U.S.C. § 226(b)(1)(A) (emphasis added). Similarly, the OCS Lands Act requires that royalties be obtained based on the "amount or value of the production saved, removed, or sold." 43 U.S.C. § 1337(a)(1). The plain language of both Acts requires that royalties be based on the value of the production *at the lease*. This statutory interpretation is well settled. *See, e.g., United States v. General Petroleum Corp.*, 75 F. Supp. 225, 235 (S.D. Cal. 1947) ("royalties are payable on the gas as it is produced at the wellhead"), *aff. sub nom., Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164, 171 (1990) ("normally gas is sold and valued for royalty purposes at the wellhead"); *Shell Oil Co.*, 52 IBLA 15 (1981) (transportation allowance to the nearest open market only needed "where no market exists at the wellhead" for crude oil).

Furthermore, Texaco's federal oil and gas leases similarly require that production be valued for royalty purposes at the lease. Texaco currently has over 600 producing federal oil and gas leases, some of which have been in effect for over seventy-five years. The leases typically provide for payment of royalties on a stated percentage of the "amount or value of production removed or sold from the lease," or, for OCS Lands Act leases, the "amount or value of production saved, removed or sold" from the leased area. Proposed benchmark 2 pertaining to the lessee's purchases at the lease complies with both settled law and binding lease terms in that it measures the value of production at the lease.

When applying this proposed benchmark, an appropriate amount of production should be required to be purchased by a lessee or its affiliate, or by third parties, before that price would be acceptable for valuing the remainder of a lessee's production that is not sold arm's-length. A simple weighted average of relevant arm's-length purchase prices would be a valid indicator of market value.

3. Outright Arm's-Length Sales by Third Parties.

Arm's-length sales by third parties at the lease are also a reliable indicator of crude oil value. However, Texaco cautions that contract terms relating to third party sales are typically unknown to the lessee. To the extent such contract terms are public information and are current and verifiable, their sales prices would be a valid indicator of value in the field. MMS should not undertake to provide historical third party contract price data for application to current sales. As set forth below, supply and demand conditions at the lease can change rapidly and may vary from one area to the next. The rulemaking record demonstrates that MMS data may be inaccurate at the lease level and could be obsolete by the time it was published.

4. Prices Published by MMS Based on its RIK Sales.

To the extent that MMS' RIK sales are current, and are made at a negotiated price in the production field or area, they would be a valid indicator of value at the lease. Use of such RIK sales prices would have the added benefit of reducing costly MMS, or designee, audits of the lessee. We again urge MMS to conduct RIK sales wherever it has any concerns over prices used for valuation purposes. (Indeed, Texaco supports a legislated mandatory RIK program where royalty would not be paid in value.)

5. Netback Employing Price Information from the Nearest Market Center or Aggregation Point.

A netback methodology should not be used for royalty valuation purposes unless no other alternative is available. As MMS itself has stated in the past, and as clearly reflected in the comments to the January 3, 1997 proposal, a netback methodology is very difficult to administer and is generally unreliable, especially given that supply and demand conditions in the relevant producing fields can change rapidly. Supply and demand conditions tend to be localized in the crude oil market. A netback methodology that ignores such localized conditions would create market inefficiencies.

To be valid, any netback methodology must allow for a full deduction of the value of services and enhancements provided, as well as costs associated with risks, after the production leaves the lease. For example, a netback methodology must account for such midstream services as the aggregation of small, diverse volumes into pools of oil suitable for sale at a market center. Costs of maintaining both in-line and storage tank inventories must be accounted for. The services of expert marketing personnel at the market center, and the efforts of those personnel who manage inventories, plan deliveries, assess storage availability and costs, and provide accounting and administrative back-up must be accounted for. A netback methodology also must take into account numerous administrative services such as scheduling the movement of crude, measuring and determining the quality of the oil, and managing the credit risks and commercial exposure in holding inventories.

In addition, significant economic risks, including environmental risks such as oil spills in transit and at storage facilities, risks of delay from equipment failure or weather conditions, risks of a rapid change in price, risks of line loss (such as unaccounted for volume shrinkage), credit risks inherent in reselling to third parties and unforeseen breakdowns in planning, all add significantly to the cost of moving crude oil. The value associated with such risks also must be accounted for in a netback methodology.

Finally, a netback methodology must also account for a reasonable rate of return on all of the services, investments and risks associated with activities away from the lease.

* * *

MMS asks in its Notice whether it should retain the gross proceeds minimum requirement of the existing regulations, so that value would be the higher of the benchmark value or gross proceeds. Texaco has no objection to the retention of the gross proceeds requirement as it was intended, and as is stated in the current regulations, *i.e.*, the gross proceeds accruing to the *lessee* for production *at the lease*. That is, all proceeds received by the lessee *in the field of production* for crude oil should be used for royalty valuation purposes. However, MMS has recently changed radically its view of the gross proceeds rule. (*See, e.g.*, June 24, 1996 Valuation Guidance For Auditing Crude Oil Premiums.) MMS now contends that resale proceeds received by an affiliate of a lessee at distant market centers are somehow viewed as gross proceeds accruing to the lessee. MMS took this position, for example, in connection with certain orders to pay based on California production. Texaco received such an order to pay and is vigorously contesting the methodology used therein. This new methodology ignores the value of multiple services, as well as the cost of multiple risks, incurred in moving oil from the lease to a market center.

MMS also asks how it can verify that "contracts are indeed arm's-length sales and that they reflect the total consideration for the value of production other than through audit." MMS' timely exercise of its option to take its royalty in kind would provide such verification. This procedure is far less costly and far more efficient than the audit process.

C. Alternative 3 — Geographic Indexing

The third alternative appears to involve creating a pricing index from some type of data system based on surveys by MMS in various, undefined, geographic areas. Such a geographic indexing methodology would very likely be unworkable, and values reported and then recorded in an MMS database generally would be obsolete by the time they were published. The marketplace often changes too rapidly, and supply and demand conditions tend to be too localized, for such a database system to work. For example, applying available indices to a large geographic area ignores changing logistical constraints applicable from one field to the next. Thus an increase or decrease in pipeline capacity, refining capacity, or production volumes, or even changes in the weather, could cause the relevant market factors to differ substantially from those used to develop the applicable geographic index. In today's market, Texaco is unaware of any pricing index that, over time, can accurately value production at the lease, which as discussed above, is the method of valuation required by law.

* * *

MMS asks whether Alternatives 1-3 should be applied only to the Rocky Mountain region, while maintaining NYMEX prices as the basis for mid-continent and OCS leases, and ANS prices for California and Alaska leases. However, as explained herein, the NYMEX and ANS based methodologies are unworkable and unlawful, and thus should be abandoned.

The NYMEX crude oil futures market is very different from the crude oil lease markets. A NYMEX official testifying at MMS's Houston hearing regarding its first proposal acknowledged that NYMEX has never researched correlations between "the lease and *our market*." (Hearing Tr. at 192.) The NYMEX is a paper market, not a "wet barrel" market. Participants in the NYMEX buy and sell futures contracts rather than actual barrels of oil -- almost exclusively to hedge or to speculate. NYMEX is a market for "risk trading" and not oil trading. NYMEX transactions neither measure prices "at the lease" nor prices at the time of production.

As set forth in the report of Dr. Philip K. Verlager, Jr. attached to our May 28, 1997 comments, the daily closing price on the NYMEX, which reflects the last two minutes of a trading day, is not a reasonable proxy for the value at the lease at the time of production. On average, there are less than .003% physical deliveries in any one month on a NYMEX contract, as compared to 75,000-150,000 contracts traded daily (an equivalent of 75-150 million barrels per day). Trading in such paper barrels relates exclusively to bulk markets, whereas production at the lease is often in small quantities, with unique quality, logistical and local market considerations that can be very different from the NYMEX paper barrel. Seventy-five percent of U.S. crude oil wells are stripper wells, which produce on average only 2.1 barrels per day.

MMS ignores price fluctuations in intra-day trading on the NYMEX. MMS proposes using the close/settlement value, which is a minuscule snapshot of time during the 24-hour trading period. (Verlager Report at pp. 1-3, 12-13.) Trading in NYMEX contracts regularly occurs during 104.08 hours of a standard week. (*Id.*). MMS proposes to use trades for royalty valuation purposes that occur in only ten minutes out of the 104.08 hours, or 0.16% of the time in which the market is open. *(Id.)* Viewed differently, a spot contract trading for twenty days out of a month would trade for 424.32 hours. *(Id.)* Yet, under the MMS proposed formula, only 1.13 hours of this trading period (0.3% of total trading time) would be sampled in the determination of settlement prices. *(Id.)* No consideration would be given to the weighted average sales price in the NYMEX trading pit, which reflects volumes traded as well as price fluctuations during the trading day. *(Id.)*

NYMEX values are also influenced by speculation about future price conditions that may have no relationship to a particular lease. (*Id.* at 3-9.) Dr. Verlager emphasizes that speculation contributes to a "risk premium" in NYMEX trading that appears especially prevalent in crude futures trading. (*Id.*). In addition, NYMEX values are necessarily influenced by pipeline delivery constraints at Cushing, Oklahoma. "Squeeze" situations by traders, and participation by commodity hedge funds and other non-commercial entities, create unique supply and demand conditions. For example, a bottleneck in certain pipeline deliveries to Cushing would create high prices at the Cushing end of the pipeline and correspondingly low prices at the opposite end of the pipeline, i.e., the field. *(See id.* at 9-10.) The influences of such a bottleneck on the Cushing price would necessarily have an opposite effect on valuation at the leases served by the pipeline. (*Id.*) (Of course, most fields are in no way connected to pipelines serving Cushing and would not be affected by such periodic pipeline constraints that influence Cushing prices.) NYMEX closing values, particularly in the last few days of the expiration of the prompt contract month, are susceptible to manipulation due to options strike prices and the opportunity for options traders to benefit from premiums on the strike prices. (*Id.* at 10-12.)

Valuation of crude oil produced in California using ANS prices is similarly inappropriate. In the Interagency Task Force Report, MMS properly rejected using ANS to value California crudes. (Final Report at App. 4, fn.1 (May 16, 1996).) As set forth in the report of Dr. Benjamin Klein attached to our May 28, 1997 comments, the State of California has one of the most diverse indigenous crude supplies of any region in the world. (Klein Report at 4.) California crudes range from heavy (*e.g.*, 13 degrees API) crude oils, sometimes with high levels of sulfur and other impurities, to light crudes (e.g., 40 degrees API) with relatively few impurities. (*Id.*) Dr. Klein states that "different crude oil fields in California are also subject to widely divergent economic influences depending on such factors as the quality of the crude, the supply and demand for different types of crude and the capabilities of local refiners in each region, the distance from the field to potential buyers, and the transportation alternatives available from each field." (*Id.* at 5.)

As set forth in the report of Samuel A. Van Vactor of Economic Insight, Inc., which is also attached to our May 28, 1997 comments, ANS is a waterborne crude oil available in tanker quantities having much different quality characteristics compared to most California crudes. (Van Vactor Report at 10.) Since 1993, for example, ANS spot prices have averaged 82¢ per barrel higher than spot prices for Line 63, a blended stream of California crudes delivered to Los Angeles with similar API gravity and sulfur content to ANS. These arm's-length price differences reflect economic and quality differences between ANS and California pipeline-delivered crudes that would not be captured by the MMS proposed methodology. (*Id.* at 6-9.) Dr. Klein's report shows that the spread between arm's-length prices of ANS and California crudes changes frequently. (Klein Report at 9-11.) Dr. Klein also shows that "[i]n addition to the large changes in relative prices between ANS and California crudes there are also large changes in relative prices of different California crudes." (*Id.*) Dr. Klein demonstrates that "[t]hese price changes reflect changes in the forces of supply and demand for different types of crude and crudes in different locations." (*Id.*)

In addition, the spot market transactions for ANS crude oil sold in California and reported by Platts are relatively thin. Only three sellers of ANS exist on the West Coast, and probably less than a dozen buyers are active. Most sales of ANS are term transactions. For competitive reasons, many transactions involve contract terms that are private and confidential, whereby both the seller and buyer agree not to report prices to the reporting services. Consequently, the validity of reporting services' price assessments for ANS are often suspect.

Spot market assessments of ANS crude oil landed in California have no justification whatsoever as a mandated mechanism for valuing California crude oil. Not only is ANS a crude grade with limited liquidity on the spot market, its physical characteristics are substantially different from most California crude oils. Even relatively higher gravity off-shore California crude oils are not only significantly higher in sulfur content and lower in gravity than ANS, but have much higher metals and nitrogen content that reduce their market value.

The fact that MMS is contemplating yet a third methodology for a "Rocky Mountain region" appears to be a testament to the fact that crude oil markets are localized. Again, however, as discussed above, royalties should be based on values at the lease, and this principle should apply not just to the Rocky Mountain region but to all regions. The NYMEX and ANS value-based methodologies should be fully abandoned and replaced in the proposal with nationwide valuation based on arm's-length transactions at the lease.

D. Alternative 4 — Proposing Substitute Location Differentials From the Lease to the Market Center Using NYMEX and ANS Values

MMS proposes that it publish location differentials based on cents per barrel or cents per mile in a zone or area, or a percentage of the NYMEX or ANS value to which the differential is applied. However, appropriate differentials between a lease and a market center are influenced by numerous economic factors and often are constantly changing. Aside from *beginning* valuation at an inappropriate point, this alternative fails to solve the problems related to adjustment that were inherent in the original proposed rule. Therefore, published differentials would not likely capture the fair value of services, or costs of risks, described above that are involved in moving crude oil away from the lease and to a market center.

MMS also requested comments on alternatives for determining quality differentials from the lease to the market center. These differentials are even more difficult to accurately capture as you move away from the lease. The record evidence shows that the price spreads among various grades of crude vary from place to place and over time and can change very rapidly. (*See* reports of both Dr. Klein and Mr. Van Vactor.) Downstream blending and even simple commingling complicate this issue enormously.

E. Alternative 5 — Use of Published Spot Prices

Alternative 5 proposes the use of a netback from published spot prices instead of NYMEX for production east of the Rockies. Aside from the many problems of netting back spot prices to the lease that are discussed above, for a number of reasons spot prices are an unreliable indicator of product values at the lease.

MMS has consistently condemned the use of either spot or futures price benchmarks as a reliable indicator of production values. For example, MMS' Associate Director was highly critical of using such benchmarks in a memorandum concerning adoption of the current regulations:

> Application of spot prices in valuing non-arm's-length disposals of lease production would not be specific. Spot prices are available only for a limited number of "benchmark" domestic crudes delivered at specific points; e.g., West Texas Intermediate at Cushing, Oklahoma. It is not clear how spot prices would be

> adjusted for differences in quality or necessary transportation between that of the "benchmark" crude and that of the crude to be valued. An adjustment for differences in API gravity alone, for example, while a reasonable price adjustment mechanism for oil produced in the same field or area, does not necessarily reflect true value differences when comparing crudes from distant areas. The price differences in crude oil nationwide depend upon a host of factors not limited solely to gravity and transportation adjustments. Factors important to the establishment of value of a particular crude include the need for an availability of crude oil supply, the cost of transportation to the refinery, the chemical compositioning characteristics of the crude oil, the cost to refine the particular crude, the mix of refined products derivable from the crude and their values, prices currently paid or offered for the same or comparable crudes, and other economic criteria. Posted prices, which exist in all the important producing areas, reflect all these considerations; "benchmark" spot prices on the other hand, cannot relate these factors specifically to each producing area. The same is true for futures prices, which also relate to a few "benchmark" crudes only.

(Memorandum from Associate Director for Royalty Management to Director, MMS, February 12, 1987.)

Published crude oil spot prices, such as Platts assessments East of the Rockies, cover only the following grades: WTI at Cushing, Oklahoma and Midland, Texas; West Texas Sour at Midland; Light Louisiana Sweet at St. James, Louisiana; Eugene Island Sour at St. James; Louisiana Heavy Sweet at Empire; and Wyoming Sweet at Guernsey, Wyoming. Yet, unlike circumstances, for example, in natural gas markets, there are dozens of other grades of crude oil produced East of the Rockies. Many of these crude oil grades have substantially different physical and market characteristics from the Platts spot price assessments, and cannot equitably be equated to those spot price values. Crude oil spot markets are less mature than, for example, natural gas spot markets, and a much smaller percentage of crude production is traded in spot markets as compared to natural gas.

Platts, of course, does not report volumes on the various spot assessments, and strong doubt exists about many of the reported grades. For example, in Texaco's experience arm's-length spot market transactions in Guernsey of Wyoming Sweet crude oil more often than not bear no relationship whatever to Platts reported spot prices.

Platts, for example, does not divulge its method of obtaining market assessments other than to state they are for one-hour time windows in the afternoon using telephone polling of selected people in the "industry." Of course, such people might be selective in the data they provide. Therefore, assessment values are subject to distortion and, perhaps, manipulation. In addition, since transactions occur between parties over a 24-hour period, the one-hour window of time used by Platts may not be a reasonable indicator, particularly if a crude grade is thinly traded and market prices are changing.

The fact that contracting parties might sometimes use a price "benchmark" such as a Platts spot price in crude oil sales contracts at the lease is not evidence that such a benchmark could or should be mandated as value for all federal lease crude oil production, or for the same lease production regardless of changing circumstances. Parties who use a price benchmark for specific sales understand the risks and circumstances involved at the time they are doing so. The same parties contracting a month later at the same lease might choose a much different price mechanism. But in either case, the current arm's-length price should be accepted for royalty value regardless of how that price may be derived.

At any given time, buyers might have unique needs for incremental spot supplies of crude oil having certain characteristics. For example, a refinery whose water-born cargo is delayed several days might enter the spot market and pay a premium significantly in excess of the average price of crude oil. Under the Alternative 5 proposal, the lessee who enjoys an above-average price would pay a lower royalty, whereas a competing lessee who sells oil below the average market price must pay a higher royalty. Such a result not only distorts market efficiencies but is inequitable.

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MMS also asks whether, if a published spot price methodology were used, it should then allow actual costs of transportation if the production flows to the market center where the spot price is published. As set forth above, limiting lessees to "actual costs of transportation" is highly unfair and would foster inefficiencies. Again, numerous other services, and risks, are involved in moving oil from a lease to a market center that are not encompassed in a deduction for only the actual costs of transportation.

Conclusion

We again commend MMS for considering alternatives that base royalties on value at the lease. We urge MMS to reject Alternatives 3, 4 and 5, which fail to follow this basic economic and legal principle. Although Alternative 1, the tendering methodology, is clearly a fair and appropriate method for valuing crude oil at the lease, it should not be a required methodology. Some companies could not effectively implement such a methodology, and it might be inefficient to use under some circumstances. Thus, purchases in the field or area, in addition to sales in the field or area, are equally valid benchmarks that should be used. We would be pleased to continue to provide any comments or other assistance to help clarify or improve methods to ascertain values of crude oil at the lease.

Thank you for your consideration of Texaco's comments.

Sincerely,

James C. Pruitt

James C. Pruitt