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BY FEDERAL EXPRESS

Mr. David S. Guzy
Minerals Management Service
Royalty Management Program
Denver Federal Center
Building 85, Room A613
Denver, Colorado 80225

Re: Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Indian Leases

Dear Mr. Guzy:

Texaco Inc., on behalf of itself and its affiliates, including Texaco Exploration and Production Inc. ("TEPI") and Four Star Oil & Gas Company, appreciates the opportunity to submit these comments on the Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Indian Leases that was published in the Federal Register on January 5, 2000 (65 Fed. Reg. 403). Texaco submitted extensive comments and suggested alternative valuation methodologies in response to the proposed rule published on February 12, 1998 (63 Fed. Reg. 7089). In addition, Texaco representatives attended the public workshop that MMS held on the proposed rule.

We are disappointed that after having specifically requested comments on alternative valuation methodologies, MMS seems to have ignored completely our comments and suggestions. The supplementary proposed rule fails to correct most of the deficiencies noted in Texaco's previous comments.[1] Most importantly, the proposal still fails to measure the true

[1] Although we will not repeat our previous comments, we hereby incorporate them for purposes of the administrative record.

value of crude oil production at the lease. Nor has MMS yet offered any rationale basis for rejecting arm's-length sales in the producing field.[2] Indeed, apart from substituting spot prices for New York Mercantile Exchange ("NYMEX") prices, the supplementary proposed rule has changed very little from the February 1998 proposal. Consequently, the proposal still fails to achieve two of its stated objectives: it does not accurately reflect the market value of Indian lease production and it does not add more certainty to valuation of oil produced from Indian lands. To the contrary, just as the initial proposal, the supplementary proposed rule is enormously complex, far more burdensome and uncertain than the current regulations, and probably unworkable. Although the proposal may seek to maximize royalty revenues from Indian leases, it does so at tremendous administrative cost to both industry and MMS. Moreover, because the proposal is unlawful, burdensome, and unfair, any short-term gains in royalty revenues will undoubtedly be offset by decreased leasing on Indian lands.

One of the more striking things about the supplementary proposed rule is its accompanying cost-benefit analysis, which fails to even acknowledge, let alone take into account, the administrative burdens identified in Texaco's previous comments. The proposal also fails to correct deficiencies that MMS has acknowledged in the context of the ongoing federal rulemaking. In addition, all three of the proposed valuation methodologies are still contrary to the express terms and conditions of Texaco's Indian leases and therefore cannot lawfully be applied to Texaco.

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[2] Texaco's previous comments criticized MMS's reliance on unnamed "experts" and consultants and noted that MMS had failed to either identify these experts and consultants or to describe the presentations that they made, thus depriving Texaco and other interested parties of the opportunity to fully participate in the rulemaking. The further supplementary proposed rule offers no further explanation of any evidence on which MMS has relied. In similar circumstances, courts have held that it is unreasonable for an agency to depart from its long-standing practices without a legitimate basis for doing so. *See, e.g., Motor Vehicle Mfrs. Ass'n of the United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 52 (1983) (an "agency must explain the evidence which is available, and must offer a 'rational connection between the facts found and the choices made'"); *Cotton Petroleum Corp. v. United States Dep't of Interior, Bureau of Indian Affairs*, 870 F.2d 1515, 1526 (10th Cir. 1989) (Assistant Secretary's disapproval of a communization agreement without reference to factors required under established agency guidelines deemed arbitrary and capricious); *Pharmanex, Inc. v. Shalala*, 35 F. Supp. 2d 1341, 1348 (D. Utah 1999) (FDA's failure to consider its own longstanding prior interpretation of a statute, and to explain why that interpretation no longer applied, constituted sufficient ground to invalidate a new interpretation); *NAACP v. United States Secretary of Labor*, 865 F. Supp. 903, 912-13 (D. D.C. 1994) (Department of Labor's unexplained change in longstanding policies regarding payment practices held arbitrary and capricious); *Stellacom, Inc. v. United States*, 783 F. Supp. 647, 655 (D. D.C. 1992) (Small Business Administration's amendment of its regulations held arbitrary and capricious because it was an unexplained departure from a near thirty-year practice).

I. THE COST-BENEFIT ANALYSIS IS FUNDAMENTALLY FLAWED

In the cost-benefit analysis accompanying the supplementary proposed rule, MMS asserts that it "would realize administrative savings because of reduced complexity in royalty determination and payment under this proposed rule." 65 Fed. Reg. at 410. The analysis further contends that the proposal will simplify reporting and pricing of Indian royalties, add certainty to royalty valuation, and reduce audit efforts, valuation determinations, and litigation. *Id.* Nothing could be further from the truth. To the contrary, the proposal is significantly more complex, burdensome and uncertain than the current rules, and, for those reasons alone, is likely to result in a dramatic increase, not a decrease, in audit efforts, valuation determinations, and litigation.

Under the regulations in effect for most of the last century, oil sold by Indian and federal lessees at arm's length has been valued based on the gross proceeds accruing to the lessee from the sale of the lease production. *E.g.*, 30 C.F.R. § 206.52(b)(1)(i). It is difficult to imagine a simpler or more certain valuation methodology, or one that better measures the value of lease production. In fact, less than one week before publication of the supplementary proposed, MMS stated in the context of the federal royalty rulemaking that "[i]t is longstanding MMS policy to rely on arm's-length prices as the *best measure of value*, and we have no intention of changing this." 64 Fed. Reg. 73820, 73829 (Dec. 30, 1999) (emphasis added). Similarly, oil not first sold at arm's length has since 1988 been valued using a series of benchmarks, with the proviso that the royalty value cannot in any event "be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined under [the regulations]." 30 C.F.R. § 206.52(c), (h).

Under the supplementary proposed rule, the lessee would have to initially value all of its Indian lease production using two entirely different valuation methodologies, compare those two values, and pay royalties on the higher of the two. Furthermore, each of the proposed valuation methodologies is, by itself, decidedly more complex and less certain than the existing rules:

- Determining the "gross proceeds" under proposed 206.52(b) would – as a result of the proposed expansion of the term "lessee" to include the lessee's affiliates – require the lessee to ascertain the ultimate disposition of every barrel of oil produced or received in exchange for oil produced from its Indian leases, which if possible at all is several orders of magnitude more difficult than anything required by the current rules. By definition, oil at an aggregation point is aggregated (*i.e.*, commingled), and from that point forward it is not possible to provide accurate and verifiable information on what happens to particular lease production. In other words, once crude oil is commingled there is simply no way to distinguish between Indian and non-Indian oil or between Indian oil from different leases. Therefore, it is generally not possible to actually trace the ultimate disposition of Indian lease production, or of oil received in exchange for Indian lease production. Rather, some allocation methodology would be required, which, of course, reduces certainty. Neither the initial proposal nor the supplementary proposed rule offers any guidance on what allocation methodologies (*e.g.*, first in first out, last in first out, *etc.*) would be acceptable to MMS. In recognition of the extraordinary administrative burden, if not the practical impossibility, of "tracing" the ultimate disposition of production from a particular lease, MMS in the federal rulemaking has proposed to allow most lessees the option of using either "gross proceeds" or index pricing to value their federal lease production. *See* 64 Fed. Reg. at 73829. Yet in the further supplementary proposed rule for Indian leases, MMS would require lessees to *both* trace the ultimate disposition of every barrel *and* compute the index price – and, incredibly, MMS contends that the proposal would simplify the reporting and pricing of Indian royalties.

- Determining the index price under proposed 206.52(a) would require the lessee to ascertain the MMS-approved, published spot price for the crude oil most similar in quality to its lease production at the market center nearest the lease, calculate the average daily high spot price for deliveries during the production month, and compute the location and quality adjustments and transportation allowance set forth in proposed 206.61(c). To accurately compute the location/quality adjustment and transportation allowance under the further supplementary proposed rule, the lessee would need to ascertain the final disposition of every barrel of lease production it or its affiliates bought, sold or exchanged during the production month, as well as the methods of transport and the "actual cost" of that transportation. For the very same reason that it is generally not possible to trace the ultimate disposition of the production from any particular lease, it is also generally not possible to accurately compute the "actual costs" of transporting that production under proposed 206.61(c). For example, under the proposal, Equilon Enterprises LLC ("Equilon"), a joint venture of Texaco Inc. and Shell Oil Company, and its subsidiaries, including Equiva Trading Company ("Equiva") and Equilon Pipeline Company LLC ("Equilon Pipeline"), would be presumed to be "affiliates" of TEPI and, therefore, would be included in the proposed definition of "lessee." Much of the oil sold by TEPI to Equiva is transported through pipelines owned by Equilon Pipeline. When Equiva purchases crude oil from TEPI, it generally commingles the oil with oil purchased from other producers, and once the oil is commingled, it cannot be traced to downstream sales transactions. In addition, there are multiple delivery points within Equilon's pipeline system, which further complicates any attempt to allocate transportation costs. Moreover, as Equilon has noted in comments filed in response to the federal rulemaking, its accounting system was not designed to capture lease specific volumes and associated transportation costs for each barrel because there is no business reason for it to need such data. Accordingly, neither TEPI nor Equilon Pipeline has the data or computer systems available to accurately calculate "actual" transportation costs under proposed 206.61(c).

The cost-benefit analysis for the proposed "initial" valuation determination ignores completely the substantial increase in time and record-keeping that would be required to complete the Report of Royalty and Remittance (Form MMS-2014). As Texaco noted in its previous comments, the current Form MMS-2014 generally assumes that there will be one type of disposition and valuation methodology for any one lease. The form does not report the information that would be required for Indian lessees to compute royalty value under the supplementary proposed rule, much less to perform the multiple comparisons that would be required. Accurate royalty valuation under the proposed rule would require tracking every transaction, and all of the transportation costs, for every barrel of Indian lease production from the lease through the first arm's-length sale. Computing transportation costs would similarly require tracing lease production downstream of the lease. The supplementary proposed rule would therefore require changes to the MMS-2014 to capture the information needed to compute the royalty valuation and perform the required multiple comparisons.

Moreover, even if a lessee were able accurately to calculate the downstream "gross proceeds" and index pricing amounts in accordance with proposed 206.52, and even if the lessee properly reported and paid its Indian royalties using the highest of those two values as required by the proposal, there still would be no certainty that the amount reported and paid was correct. Rather, the lessee would have to review the Federal Register each day thereafter for an indefinite period, in case MMS published a "major portion" value for a designated area that was higher than any of the royalty values reported and paid by the lessee for any of its Indian leases within that designated area. Compliance with just the "major portion" provision of the supplementary proposed rule would require TEPI to retain a specially trained person to review the Federal Register every day, compare MMS's "major portion" notices with all of the MMS-2014s previously filed for leases within the applicable designated areas, and make the necessary revisions to the MMS-2014s. MMS's cost-benefit analysis includes only the estimated, incremental cost of filing supplemental MMS-2014s, and ignores entirely the cost of subscribing to the Federal Register, reviewing it every day, and ascertaining whether any of the reported "major portion" values are higher than the royalties previously paid.

Hence, contrary to the flawed assumptions used in the cost-benefit analysis, the proposal would dramatically increase the cost and difficulty of compliance. The proposed rule would result in increased cost to attempt to trace Indian lease production to the first, downstream arm's-length sale. Computer systems would need to be changed to capture sales and exchange data, calculate prices, and perform recalculations whenever any component of the price changes. The proposal would also result in increased cost to collect information necessary to pay royalties based on index pricing. New computer systems would be necessary to develop prices and retain information on an historical basis in order to make prior period adjustments. Existing computerized revenue systems would likely require significant modification to accommodate the dual pricing methodologies. The proposed changes in allowable transportation deductions would also result in reduced deductions and increased costs.

In addition, the proposal would result in a significantly increased audit burden on both MMS and industry. Tracing affiliate resale proceeds, calculating permitted allowances and adjustments, and determining the appropriate index and "major portion" values would make future audits significantly more complicated. Industry would be faced with increased record-keeping requirements in order to document all of the components of the weighted average price calculations for affiliate sales. In short, far from simplifying or adding certainty to the valuation of Indian lease production, the proposed duplicative royalty computation and multiple comparisons would unnecessarily complicate royalty valuation, increase costs, and reduce certainty with no countervailing benefit (other than to artificially, and unlawfully, inflate the royalty value for Indian lease production).

II. THE PROPOSED RULE FAILS TO CORRECT DEFICIENCIES THAT MMS HAS ACKNOWLEDGED IN THE FEDERAL RULEMAKING

Inexplicably, despite having acknowledged the similarity between the proposed Indian and federal rules,[3] the supplementary proposed rule fails to correct deficiencies that MMS has expressly recognized and attempted to correct in the ongoing rulemaking for establishing oil value for royalty due on federal leases.

- For example, in the further supplementary proposed rule for federal leases, published on December 30, 1999, MMS proposed a factor-based test for determining control for purposes of defining "affiliate" in light of the decision of the United States Court of Appeals for the District of Columbia Circuit in *National Mining Association v. Department of the Interior*, 177 F.3d 1 (D.C. Cir. 1999). *See* 64 Fed. Reg. at 73826. In that case, the court struck down the Office of Surface Mining and Reclamation and Enforcement's "ownership and control" rule, which, like the existing MMS rule and the proposed rule for valuing Indian royalties, presumed control under circumstances where one entity owned between 10 and 50 percent of another entity. Although the same office of MMS is responsible for both rulemaking efforts, the supplementary proposed rule for Indian royalty valuation – published one week after the further supplementary proposed rule for federal royalty valuation – made no change to the proposed definition of "affiliate."

- Additionally, in the further supplementary proposed rulemaking for federal royalty valuation, MMS offered most lessees the option of using index pricing when it would be overly burdensome to "trace" the ultimate disposition of lease production for purposes of computing the resale "gross proceeds." The supplementary proposed rule for Indian royalty valuation, on the other hand, fails to even acknowledge the difficulty of tracing lease production.

- MMS withdrew the proposed Form MMS-4415 for federal lease production, which was widely criticized as being highly costly and largely useless, yet the supplementary proposed rule would require Indian lessees to file the nearly identical Form MMS-4416.

- In the further supplementary proposed rule for federal royalty valuation, MMS acknowledged the need and provided, at least in certain circumstances, for binding value determinations. See 64 Fed. Reg. at 73832 – 73833. Yet, the supplementary proposed rule for Indian royalty, although based on the same stated objective of adding certainty to royalty valuation, fails to provide for binding value determinations under any circumstances.

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[3] As Texaco noted in its previous comments, MMS has publicly acknowledged the similarity between the proposed rules: "The Indian Rule as it exists today is tied directly to the Federal Rule with one exception [the major portion value]." (Transcript of MMS Hearing in Albuquerque, N.M., Mar. 26, 1998, at 5); "In a nutshell, the current Indian rule is tied directly to the federal rule" (Transcript of MMS Hearing in Denver, Co., Apr. 1, 1998, at 4).

- Finally, the further supplementary proposed rule for federal royalty valuation, but not the supplementary proposed rule for Indian royalties, would provide that a change in ownership of a transportation system would result in a new depreciation schedule for purposes of the allowance calculation.

It is a fundamental precept of administrative law that agencies are required to treat like cases alike. *See Freeman Eng'g Assocs. v. FCC*, 103 F.3d 169, 178 (D.C. Cir. 1997) ("Further, an agency may not 'treat like cases differently'") (quoting from *Airmark Corp. v. FAA*, 758 F.2d 685, 691 (D.C. Cir. 1985)); *Independent Petroleum Association*, 92 F.2d at 1260 ("The treatment of cases A and B, where the two cases are functionally indistinguishable, must be consistent. That is the very meaning of the arbitrary and capricious standard."); *LaShawn A. v. Barry*, 87 F.3d 1389, 1393 (D.C. Cir. 1996) (*en banc*) (treating like cases alike is "the most basic principle of jurisprudence"); *Henry v. INS*, 74 F.3d 1, 6 (1st Cir. 1996) (In other words, administrative agencies must apply the same basic rules to all similarly situated supplicants. An agency cannot merely flit serendipitously from case to case, like a bee buzzing from flower to flower, making up the rules as it goes along."). There is simply no rational basis for MMS to recognize and attempt to correct deficiencies in one rulemaking and ignore the same deficiencies in another.

III. ALL THREE OF THE PROPOSED VALUATION METHODOLOGIES ARE CONTRARY TO THE PLAIN LANGUAGE OF TEXACO'S INDIAN LEASES

The February 1998 proposal would have required that royalty value be based on the highest of three comparative values: (1) the average of the five highest daily NYMEX futures prices at Cushing, Oklahoma, for the Domestic Sweet crude oil contract for the prompt month, (2) adjusted resale "gross proceeds," and (3) a "major portion" value for the MMS-designated area to be calculated by MMS within 120 days after the end of each production month. This comparative valuation methodology would, according to MMS, better implement the "major portion" provisions of many Indian leases. In addition, MMS stated that "[w]hen the lessee entered into the lease, it expressly agreed that the Secretary will determine royalty value and that value may be calculated based on the price paid for the major portion of oil sold from the field where the leased lands are located," and "the lessee agreed to abide by and conform to the Secretary's regulations." 63 Fed. Reg. at 7093.

In the supplementary proposed rule, MMS proposes, presumably based on the same interpretation of Indian lease provisions, to use spot rather than NYMEX values for the first of the three comparative values. The proposal notes, however, that because MMS agrees "that applying the average of the five highest NYMEX settle prices was unfair and unrealistic and .... represented a price most sellers could not obtain under any circumstances," MMS is proposing to use the average of the highest daily spot prices for the month. 65 Fed. Reg. at 404. MMS asserts that "[t]his should better reflect values generally obtainable, while at the same time fulfilling MMS's trust responsibility to Indian lessors." *Id.*

The supplementary proposed rule still fundamentally misconstrues the royalty provisions of Indian leases. Contrary to MMS's interpretation, standard Indian lease forms do *not* contain an express provision agreeing that the Secretary will determine royalty value. Nor do they contain an unqualified agreement by the lessee to abide by and conform to the Secretary's regulations.

Until the mid-1930's, standard Indian lease forms typically provided for royalties to be paid based on a stated percentage of "the gross proceeds of all crude oil extracted" from the leased lands, with the proviso that "in no event shall such royalty be paid on the basis of less than the posted market price for oil of like quality, grade and gravity in the particular oil field of which said lease is a part the day the oil is run to the pipeline or into permanent storage." *E.g.*, Oil & Gas Mining Lease – Allotted Indian Lands (Form 5-154h) (circa 1930). Beginning in the mid-1930's, Indian lease forms generally required that royalties be paid based on a stated percentage of the amount or value of oil produced from the leased lands. *E.g.*, Form 5-154h (April 24, 1935). As discussed in Texaco's previous comments, this language has consistently been construed to require valuation of the lease production at the lease. Moreover, unlike federal lease forms, except for the "major portion" provision discussed below, the standard Indian lease forms do not contain a provision enabling the Secretary to determine royalty value. The "regulations" provision of Indian leases is also very limited. Not all of Texaco's Indian leases require the lessee to abide by regulations promulgated by the Secretary. Those that do contain an express limitation "[t]hat no regulations hereafter approved shall effect a change in the rate of royalty or annual rental herein specified without the written consent of the parties to this lease." *Id.*

Just as the initial proposal, both the proposed comparative valuation methodology and all three of the proposed comparative values contravene the plain language of standard Indian leases.

A. Spot Prices

In initially proposing to use NYMEX futures prices, MMS acknowledged that "the most difficult problem would be to make appropriate location and quality adjustments when comparing the NYMEX crude with the crude produced." 63 Fed. Reg. at 7092. MMS now proposes to use spot rather than NYMEX prices based largely on the fact that "when the NYMEX futures price, properly adjusted for location and quality differences, is compared to spot prices, it nearly duplicates those spot prices." 65 Fed. Reg. at 403. As pointed out in Texaco's previous comments, NYMEX is a flawed and unreliable indicator of all types of crude oil prices at the time and place of production and would lead to substantial valuation errors. Hence, the fact that spot prices may be comparable to "properly adjusted" NYMEX futures prices is no basis for assuming that spot prices are any more appropriate than NYMEX futures prices for valuing crude oil in the producing field.

Instead of measuring the value of lease production in the producing field, as required by the terms of Texaco's Indian leases, proposed 206.52(a) would impose an artificial, alternative value based on the monthly average of the highest daily mean spot prices for "similar" quality oil at the nearest market center. Moreover, just as the initial proposal, the further supplementary proposed rule fails to make the location and quality adjustments necessary to compare spot prices with the crude produced. Proposed 206.61(c) would require adjustments for MMS-published location/quality differentials, location/quality differentials specified in arm's-length exchange agreements, and premia or penalties determined from a pipeline quality bank. As noted in Texaco's previous comments, the proposed MMS-published location/quality differentials would be based on irrelevant, year-old information and, consequently, would have no relationship to current market conditions. The other two adjustments account only for the difference between the lease production and the oil ultimately disposed of; they have nothing to do with the difference in quality between the lease production (or oil ultimately disposed of) and the "similar" oil on which the spot price is based. In other words, even if there was a location/quality differential specified in an applicable arm's-length exchange agreement and even if the oil was transported through a pipeline with a quality bank, those adjustments still have nothing to do with trying to equate the quality of the spot price oil to the quality of the lease production. By failing to account for the difference in quality between the index oil and lease production, the supplementary proposed rule fails to measure royalties based on the value of the lease production, as required by the terms of Texaco's Indian leases.

The use of crude oil spot prices is also problematic for at least three other reasons: the number of transactions often is too small to provide any statistical certainty, there is no uniform method for calculating spot market averages, and the accuracy of any report depends heavily on the skills of the individual journalist covering the market on a given day. (*See* Affidavit of Marshall Thomas, ¶¶ 59-62 (submitted in support of comments filed by American Petroleum Institute in response to the January 1997 proposal on federal royalty valuation).) Published crude oil spot prices, such as Platts' assessments East of the Rockies, cover only the following grades: West Texas Intermediate 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 at Empire, Louisiana; and Wyoming Sweet at Guernsey, Wyoming. Price spreads among those grades and places fluctuate widely. There are dozens of other grades of crude oil produced East of the Rockies for which there are no published spot prices. In addition, 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 does not report volumes for its published spot price assessments, and doubt exists about certain of the reported grades. Platts also does not divulge its method of obtaining market assessments other than to state that they are for one-hour windows of time 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, contrary to MMS's assertion that such publications reporting spot prices are "independent" of MMS and industry, assessment values are subject to distortion. 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 if a crude grade is thinly traded and market prices are changing.

Moreover, spot price contracts are not representative of transactions at the lease and do not "reflect values generally obtainable," particularly when only the highest daily spot prices are included in the average. In California and elsewhere, the majority of crude oil volumes are sold through term sales rather than one-time spot sales. (*See* Comments of Professor Benjamin Klein, attached as Exhibit 4 to Texaco's April 6, 1998 Comments on the Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Federal Leases, at p. 6) Because offers for spot sales opportunities are relatively inconsistent, and the cost of maintaining inventories is high, refiners over time have opted to secure as much of their crude supplies as possible using term contracts. (*Id.*, at 6-7.) Thus, market demand for spot purchases is thin, and rationally so. The consequences of using spot prices to value lease production can be serious overvaluation depending on market conditions. For example, economic and market conditions that force refiners out of the term supply arrangements and shape spot market transactions are typically distortive, unforeseen events, which have uneven and short-lived effects on crude markets. These events, such as the Persian Gulf War uncertainty, major refinery fires, and similar occurrences, can result in significant short-term price differentials. (*Id.*)

Consistent with Dr. Klein's analysis, in 1987, the MMS Associate Director for Royalty Management appropriately rejected a proposal to use spot prices to value federal lease production, reasoning that it would be "contrary to existing law, lease, terms, and regulations, or too impractical and nonspecific to administer." Letter from Associate Director for Royalty Management to Director, MMS, "Review of Analysis Titled 'Crude Oil Royalty Valuation Monitoring System,' Policy, Budget, and Administration" (Feb. 12, 1987). The Associate Director further noted that while MMS could change the regulations, as MMS is attempting to do in the supplementary proposed rule, the use of spot prices would still be precluded by existing statutes and federal lease terms, which, like Indian lease terms, require that royalty be paid based on a percentage of the amount or value of production removed or sold from the leased lands. Neither the underlying statutes, lease terms, nor basic economic principles have changed since the Associate Director's 1987 letter. Accordingly, proposed 206.52(a) would, if promulgated as a final rule, be unlawful.

B. Downstream Resale Prices

Proposed section 206.52(b) would – by broadly defining "lessee" to include the lessee's affiliates and using downstream resale prices without allowing appropriate deductions for value added downstream of the lease – include in the royalty base the value of affiliates' downstream assets and services. Once crude oil leaves the field in which it is produced, its value is generally increased. *See, e.g.*, Comments of Benjamin Klein, at pp. 15-17 (attached as Ex. 2 to Texaco's

May 12, 1998 Comments). This increased value is attributable to numerous services and assumptions of risks, including for example: (a) transportation services, including the need for substantial inventory to fill crude oil pipelines necessary for the crude oil to flow to its destination; (b) storage services, including the use of major storage facilities at market centers, inventory to fill tanks and personnel to maintain the inventory; (c) assumptions of risks, including economic risks of changes in the price of crude oil before its resale, credit risks, environmental risks, and risk of product loss incurred away from the lease; (d) administrative services including office facilities and salaries for personnel involved in technical as well as marketing services; and (e) administrative overhead. In addition, crude oil is frequently blended downstream of the lease with other crudes. Crude oils may be blended for a variety of reasons, such as mixing together a heavy, viscous crude with lighter crudes to facilitate more efficient movement of the blended stream through an unheated pipeline or blending together crudes of different qualities to achieve the specifications desired by a particular refinery. These downstream services both change the physical composition of the crude oil and increase its value because they bring the oil closer to the point of consumption and aggregate it into the volume, with the particular specifications, and at the location and time desired by a downstream purchaser.

It is not surprising, therefore, that the price of oil at a downstream resale point or market center is generally substantially higher, after performance of these services and assumptions of risks, than the fair market value of the product removed or sold from the lease. In addition, crude oil sold at a downstream resale point or market center usually cannot be traced back to any particular lease. Whether or not blended with a different grade of crude, crude oil produced from numerous federal and non-federal properties is commingled in a pipeline where the identify of particular barrels of lease production is lost. As a result, it is generally impossible to determine the actual downstream resale price of a particular barrel of lease production.

For all of these reasons, the most accurate measure of the market value of production at the lease is arm's-length purchases and sales of like-quality crude oil in the same producing field. *See Shamrock Oil & Gas Corp. v. Coffee*, 140 F.2d 409, 410 (5th Cir.) (to determine "market price" the court must look to "the price that is actually paid by buyers for the same commodity in the same market"), *cert. denied*, 323 U.S. 737 (1944); *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984) (the "best means of determining the market value at the well ... would be to examine comparable sales"), *cert. denied*, 471 U.S. 1005 (1985); *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir.) ("It is obvious that comparable sales or current market price is the best [evidence of value], and second would come the work-back method."), *cert. denied*, 434 U.S. 921, *reh'g. denied*, 434 U.S. 968 (1977); *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996) ("Market value is the price a willing seller obtains from a willing buyer.")

By contrast, downstream resale prices, just like spot prices for oil sold in market centers, include increased value from downstream assets and services that is not part of the value of production and would not be reflected in the market price at the lease regardless of whether the oil is sold to an affiliate or at arm's-length to an unaffiliated party. Accordingly, courts have consistently held that the value added downstream of the lease is not properly included in the royalty base. *See, e.g., Amerada Hess Corp. v. Department of Interior*, 170 F.3d 1032, 1037 (10th Cir. 1999). For example, in *California Co.*, the District of Columbia Circuit, in defining the term "value of production," took care to note that it had *not* included any value added downstream of the lease:

> Let us here insert a cautionary parenthesis. No transportation costs are involved in this case. *The Secretary is not here claiming that costs incurred in moving gas from the field in the neighborhood of the wells to a distant selling point are includable in the royalty base.* This gas was conditioned by the seller and delivered to the purchaser in the field within a short distance of the wells. There were no transportation costs.... Neither are manufacturing costs involved here. The product was not transformed.

296 F.2d at 387 (emphasis added).

Similarly, in *Marathon Oil Co. v. United States*, the district court, although finding that in the absence of comparable sales at the lease MMS could properly consider downstream resale prices "as a means to determine the reasonable value of production at the lease," also made clear that it was necessary to deduct from the resale prices the costs incurred downstream of the lease – including a reasonable rate of return on the lessee's capital assets – in order to "yield an estimated wellhead value for the gas." *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1385-86 (D. Alaska), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987). *See also Piney Woods Country Life Sch.*, 726 F.2d at 240 ("On royalties 'at the well,' therefore, the lessors may be charged with processing costs, by which we mean all expenses subsequent to production, relating to the processing, transportation, and marketing of gas or sulfur. We emphasize, however, that processing costs are chargeable only because, under these leases, the royalties are based on value or price at the well. Processing costs may be deducted only from valuations or proceeds that reflect the value added by processing.")

Consistently, although the Interior Board of Land Appeals ("IBLA") has held that downstream resale prices are a "relevant matter" that may be considered in valuing lease production, particularly in the absence of a market at a lease "where the oil would ordinarily be sold and valued," *Shell Oil Co.*, 52 IBLA 15, 20 (1981), it has also consistently made clear that value added downstream of the lease must be deducted from the resale prices in order to properly value production for royalty purposes. *See, e.g., Blue Dolphin Exploration Co.*, 148 IBLA 72, 76-77 (1999); *Xeno, Inc.*, 134 IBLA 172, 178 (1995). In *Xeno, Inc.*, for example, the IBLA explained that:

> This Board has also held that the sale price received by an affiliate of the lessee in the first arm's-length transaction is properly considered in determining the value of gas produced under the gross proceeds rule.
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> However, this does not conclude the inquiry into the proper valuation of production for royalty purposes. When gas is valued at a point downstream from the wellhead where the value of production is ordinarily determined, allowances are generally required for the value added to the gas after production.

134 IBLA at 179-80; *accord Blue Dolphin*, 148 IBLA at 81 (allowance for cost of manufacturing appropriate when liquid hydrocarbons were already in marketable condition); *Exxon Corp.*, 118 IBLA 221, 255 (1991) (manufacturing allowance is appropriate for cost of operations, including dehydration, that are not needed to condition the product for market); *Mobil Producing Texas & Mexico, Inc.*, 115 IBLA at 172 ("A transportation allowance recognizes that the price received for a product at a distance from the point of production is not the value of the product at the point of production because the costs incurred in transporting the product have added value to it.")

The proposed rule's failure to allow a deduction for the value of assets, services and risks incurred downstream of the lease improperly captures that added value in the royalty base in contravention of the plain language of Indian leases. Furthermore, because including such value would effectively raise the royalty rate for Indian leases, even if the supplementary proposed rule were promulgated as a final rule it would expressly be made inapplicable under the leases' "regulations" provision.

C. Major Portion

Not all of Texaco's Indian leases has a "major portion" provision. Those that do contain language substantially as follows:

> During the period of supervision, "value" for the purposes hereof may, in the discretion of the Secretary, be calculated on the basis of the highest price paid or offered (whether calculated on the basis of short or actual volume) at the time of production for the major portion of the oil of the same gravity, and gas, and/or natural gasoline, and/or all other hydrocarbon substances produced and sold from the field where the leased lands are situated, and the actual volume of the marketable product less the content of foreign substances as determined by the oil and gas supervisor. The actual amount realized by the lessee from the sale of said products may, in the discretion of the Secretary, be deemed mere evidence of or conclusive evidence of such value.

E.g., Form 5-154h (April 24, 1935). The "major portion" provision expressly limits the Secretary's discretion in establishing royalty value. Most importantly, it plainly requires that the value be based on *prices* paid or offered for *oil of the same gravity* and *from the same field* as the lease production. Second, it provides that the Secretary may consider the *lessee's* gross proceeds as either mere evidence or conclusive evidence of the major portion value. The term "lessee" is defined in the leases to mean the entity to whom the lease was issued and does not include other "affiliated" entities.

In contravention of the straightforward language of the major portion provision, MMS has effectively interpreted the major portion value to mean the highest *royalty* paid by other Indian lessees to lessors in the same tribe. The proposed initial royalty valuation would be based on artificially inflated values that are based on neither the "prices paid or offered for oil of the same gravity and from the same field as the lease production" nor the *lessee's* gross proceeds. MMS would then array the reported royalty values from lowest to highest and select as the major portion value the royalty paid on the 75th percentile of reported volumes. Thus, like the comparative values used in the proposed initial valuation, the major portion comparison has nothing to do with prices paid or offered for oil of the same gravity and from the same field as the lease production. Nor is it based on the lessee's gross proceeds. Accordingly, the proposed major portion valuation is completely contrary to the plain language of Texaco's Indian leases.

Moreover, contrary to MMS's apparent belief, there is nothing in either the major portion provision or the Secretary's trust responsibility that gives the Secretary – or the Indian lessors – the right to unilaterally breach the essential terms of Indian leases.

IV. THE TRANSPORTATION ALLOWANCE IS STILL INADEQUATE

Commendably, the supplementary proposed rule would permit an allowance for "actual costs" of transportation from the lease to the designated area boundary. However, as Texaco's previous comments demonstrated, the proposed allowance for "actual costs" of transportation fails to consider the full cost, let alone value, of midstream transportation assets and services. In addition, because of the difficulty of trying to "trace" lease production downstream, computing "actual costs" of transportation would be extraordinarily difficult, if not impossible. Texaco urges MMS to hold a workshop on transportation and quality adjustments and to give adequate attention to these issues.

V. CONCLUSION

In summary, Texaco urges MMS to withdraw the "Supplementary Proposed Rule for Establishing Oil Value for Royalty Due on Indian Leases" because it does not provide for value at the lease and it unfairly and unlawfully attempts to boost Indian revenues by effectively raising the royalty rate for crude oil production. The proposed rule conflicts with the essential terms of Texaco's Indian leases. The proposal is also arbitrary and capricious because it abruptly changes decades of settled policy and practice without a legitimate reason. Moreover, even if MMS were to promulgate the proposal as a final rule, the proposed valuation methodology could not lawfully be applied to Texaco's existing Indian leases. Texaco stands ready to assist MMS in any effort to clarify or improve methods to ascertain values of crude oil at the lease, as required by statute and the terms of Indian leases.

Sincerely,

James C. Pruitt

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