Thrasher, Sandra Jo

From: Ken Leonard [Leonard@api.org]
Sent: Monday, November 10, 2003 1:59 PM
To: Ken Leonard; MRM Comments
Cc: Gebhardt, Sharron; Querques Denett, Lucy; Gibbs Tschudy, Deborah
Subject: RE: Attn: Federal Oil Valuation Proposed Rule Comment

RSTF Final.PDF
(848 KB)

Lucy, Sharon, Debbie: here are our comments alone, we'll send the attachments separately because the entire package is to large to get through your fire wall. Hard copies are being delivered to Lucy this afternoon and to Debbie and Sharon by overnight mail. Sorry for any inconvenience.

-----Original Message-----
From: Ken Leonard
Sent: Monday, November 10, 2003 2:32 PM
To: 'MRM.comments@mms.gov'
Cc: 'sharron.gebhardt@mms.gov'; Lucy Querques Denett (E-mail); Debbie Gibbs-Tschudy (E-mail)
Subject: Attn: Federal Oil Valuation Proposed Rule Comment

Dear Ms. Gebhardt: Attached please find the comments, with five attachments, of the Royalty Strategy Task Force on the MMS' Proposed Federal Oil Valuation Rule. I am sending these comments on behalf of the American Petroleum Institute, Domestic Petroleum Council, Independent Petroleum Association of America and the US Oil and Gas Association. In addition to this electronic copy we are sending you several hard copies by mail to facilitate your review. Please call me or David Deal at Fulbright & Jaworski, 202-662-4633, if you have questions.

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November 10, 2003

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Minerals Management Service Federal Oil Valuation Proposal, 30 CFR Parts 206 and 210, 68 FR 50087 (Aug. 20, 2003)

Dear Ms. Gebhardt:

On behalf of the Royalty Strategy Task Force, a coalition of varied producers and their trade associations, the American Petroleum Institute, the Independent Petroleum Association of America, the Domestic Petroleum Council and the U.S. Oil and Gas Association, we welcome the opportunity to file these comments on the Minerals Management Service (MMS) August 20, 2003, Federal oil valuation proposal ("Proposal"). Together, our members account for virtually all of the royalties paid for oil production from Federal lands, both onshore and offshore.

Our comments augment the discussions held at the MMS pre-proposal workshops held March 4-6, 2003, and materials submitted by Industry thereafter. Overall, our comments are directed at a final oil valuation rule that promotes clarity and reasonable certainty, eliminates unnecessary administrative costs for all stakeholders and decreases appeals and litigation with minimal impacts on royalty revenues.

A. General Principles

The Proposal would affirm two bedrock royalty valuation principles. First, DOI "reaffirms that the value of production for royalty purposes of crude oil is value of crude oil at or near the lease. Proposal at 50088. However, "in determining value at the lease of production not sold under an arm's length contract at the lease, MMS is not restricted to a comparison to arm's length sales of other production occurring in the field or area." Id. If the MMS begins with a downstream price or value, the MMS would deduct the costs of transportation to downstream sales points or markets, or by making appropriate adjustments for location and quality. Id.

Second, Federal lessees are not obligated to sell crude oil downstream even if it might result in a higher royalty value for the production than disposition at or near the lease. Id. However, a lessee choice to sell downstream "does not make otherwise non-deductible costs deductible." Id., citing IPAA v. DeWitt, 279 F.3d 1036 (D.C. Cir 2002).

Industry welcomes a clear expression of these principles and is hopeful this contributes to the clarity and reasonable certainty that the final rule should exhibit.

B. Indexing 30 CFR §§ 206.103 & 206.104

At the core of the 2000 Oil Rule was the replacement of a benchmark system with an index-based system; the Proposal does not alter that approach but does alter the specifics of indexing in important ways. The Proposal reflects an MMS judgment that NYMEX might serve as an adequate index (for most areas) in lieu of other published spot prices at market centers. Proposal at 50088. As conceived, the MMS' NYMEX-centered proposal involves a basic approach:

- Use NYMEX as the starting point or base for valuation (calculated by averaging the daily NYMEX settlement prices for each trading day in the production month for deliveries in the "prompt month");
- Apply the "roll" (+ or –) as appropriate (to account for trends in future prices upward or downward);
- Apply a market center differential (+ or –) as appropriate to account for a specific grade of crude at a market center other than Cushing (the market center associated with NYMEX);
- Apply an adjustment (+ or –) for location and quality as appropriate to account for lease to market center differences.

Proposal at 50092. However, the "devil is in the details" and Industry has several comments on this aspect of the Proposal, some of which are prompted by questions and comments by the MMS itself in the Proposal.

1. Shift from spot prices to NYMEX. While Industry continues to believe that the MMS' underlying rationale for categorically abandoning benchmarks in favor of an indexing approach is flawed, three years of experience suggests that indexing is a workable starting point for valuation of non-arm's length transactions. Moreover, based on that experience we believe that shifting from spot prices to NYMEX in § 206.103 is a workable refinement of the current oil valuation rule.

2. Retention of ANS spot prices as the valuation basis in California and Alaska instead of NYMEX. Past Industry comments underscored the complications of oil valuation regulations that employed several geographically-based valuation standards, and appreciates the MMS' examination of NYMEX as the default index applicable in most areas.

Industry believes it would be convenient and cost-effective to have a single starting place for all index-based valuations, namely, NYMEX. The spot price for ANS, when applied on a production month (or calendar month) basis, as prescribed in the 2000 Oil Rule includes a WTI assessment (namely, Platts spot WTI) coupled with a next month ANS trade differential. Since the MMS Proposal would apply production month grade differentials to production month WTI assessments for production outside of California, retaining the current Spot ANS methodology would cause California to be disconnected from other areas in terms of how differentials are applied to a production month WTI assessment. However, the disconnect is merely a time shift in the application of differentials and would not have a material impact over time. Accordingly, Industry is not opposed to retaining ANS as the California index, but recommends that MMS consider applying market center differentials, such as Kern River and Line 63, to the ANS index to establish location and quality differentials between Long Beach (where ANS is assessed) and other viable market centers where Federal production typically flows.

California aside, Industry has never objected to the use of ANS spot prices for Alaska North Slope production.

As to the Rocky Mountain Region, Industry agrees with the MMS that the NYMEX calendar month average has a higher correlation with actual transactions in the Rocky Mountain Region than WTI spot prices as prescribed in the 2002 Rule.

3. Timing and application of the "roll." The MMS Proposal describes the "roll" at some length as an adjustment mechanism that might be employed to account for the fact that forward NYMEX prices are future price estimates suggesting that some adjustment upward or downward is appropriate to provide a better correlation between actual market center transactions. Proposal at 50089-50091.

The MMS asks whether the "roll" should be included in the calculation of the proper NYMEX price. Proposal at 50091. As proposed, the roll would be applied only outside Alaska, California and the Rocky Mountain Region, and the MMS asks whether this limitation is appropriate. Id. Industry believes the roll should not apply to Alaska, California and the Rocky Mountain Region. The roll should also not apply to the Western Gulf of Mexico, or the San Juan Basin, or any other area that does not have a market center where physical exchanges between that market center and Cushing WTI are prevalent and transparent.

As to the application of the roll generally, even outside the excluded areas the roll should not be a foregone conclusion; one size does not fit all. Substantial market evidence of actual transactions, which include the roll, must be present in order for the roll to be considered applicable for an individual lease, field, area or market center. Companies are quite differently situated and, among the major producers that engage in non-arm's length transactions, application of the roll would reflect market transactions for some but could lead to inflated values for others. This upward bias for certain trading companies exists because, even over a long period where the frequency of backwardation (current price higher than outer month prices) and contango (current price lower than outer month prices) is balanced, there is a bias toward backwardation.

Indeed, the MMS itself proposes to amend § 206.103 to expressly allow MMS termination of the roll at the end of two year periods, starting with the date of promulgation, if it no longer reflects the market. Proposal at 50090. Inasmuch as a feature like the roll is only useful so long as it supports better estimates of market value, Industry supports the proposed qualification on use of the roll with the proviso implicit in the preceding comment: that even for a particular area the roll should not be applied monolithically but tailored to meet the circumstances.

4. Treatment of holidays and weekends. Separate from application of the roll, the MMS would exclude in the definitions of § 206.101 weekends and holidays for the calculation of the average NYMEX price. Proposal at 500091. The MMS also asks what price should be assigned to days for which no price is published? Proposal at 50089-50090.

In arm's length transactions using a NYMEX pricing basis, inclusion of weekends and holidays varies from contract to contract. The price in effect on the last day the market was open is often considered the best indicator of value and remains in effect on subsequent days when the market is closed. As a result, weekends and holidays are often included because production occurs on days when the market is closed, and market value must be determined when production occurs. However, weekends and holidays are often excluded in NYMEX-based contracts.

Because of these differing business practices, Industry has formed no clear consensus as between including or excluding weekends and holidays for the purpose of calculating the value of production for royalty purposes, but recognizes the benefit of designating a single method to simplify the royalty valuation process.

5. Adjusting the NYMEX price for transportation costs and location and quality differentials. The MMS asks whether lessees should use the location and quality differentials in their own arm's length exchange agreements between Cushing and the lease or market center in preference to WTI differentials. Proposal at 50091.

Requiring lessees to calculate a weighted average arm's length trade differential between a market center and Cushing on a contemporaneous basis could result in an unnecessary administrative burden for lessees and auditors, especially in instances when a lessee has many arm's length exchanges each month. Inasmuch as daily assessments of WTI differentials likely include lessees' arms length exchange differentials, there should be little variation between the two methods when compared to each other over time, so the royalty revenue impacts should be de minimis.

Industry suggests, therefore, that the regulations be revised to allow a lessee to use WTI differentials in lieu of calculating its own location and quality differentials. Such an option could be linked with a two-year commitment to use it as the MMS has already provided elsewhere in the regulations (e.g., option to use index in lieu of gross proceeds when using exchange agreements or when selling production to an affiliate). Such an option also reinforces an overall "let form follow function" approach that offers reasonable certainty, but avoids inordinate complexity without compromising the MMS audit function and lessee accountability.

6. Determining differentials for NYMEX price in absence of information in exchange agreement. Citing the absence of many producers in the Rocky Mountain Region (and perhaps other areas) having actual trades of crude to Cushing, the MMS proposes that the WTI differential for Guernsey Sweet or an alternative be used. Proposal at 50091. The MMS also asks whether there are alternative valuation procedures for valuation of sour crude oil insofar as the WTI price at Cushing is for light sweet crude (e.g., start with Hardisty then adjust for transportation). Proposal at 50092.

From the outset of the rulemaking leading up to the 2000 Oil Rule, the use of indices for the Rocky Mountain Region was considered problematic, and the 2000 oil valuation rule preserved three benchmarks for the region. At this point, Industry questions whether additional special purpose, limited application provisions are needed and suggests that the three benchmarks and the alternative valuation provision currently prescribed for the Rocky Mountain Region are already adequate.

7. Calculation of adjustments and transportation allowances. The MMS proposes to amend § 206.112 to prescribe that, where the NYMEX price is used as the starting point for valuation, the NYMEX price would be adjusted by applying transportation costs or location and quality differentials between the lease and the market center, then adjusted further between the market center and Cushing. Proposal at 50092. The MMS proposes further that where not all, but at least 20%, of the oil is transported or exchanged to or through a market center (i.e. less than 80% is transported to lessee's refinery), the lessee must use a volume-weighted average of adjusted NYMEX prices for the non-exchanged or non-transported quantity. Where the exchanged or transported quantity is less than 20% (i.e., more than 80% is transported to lessee's refinery), the lessee must propose to MMS a differential, using the proposed differential until the MMS prescribes a different differential, and adjust as necessary after the MMS rules on the lessee proposal. In describing this feature, the MMS explains that the 20% threshold was selected because it is greater than the royalty percentage under the typical offshore lease (16 2/3%). Proposal at 50093. Allowing a lessee to base the value of production that goes to its refinery on a volume-weighted average price using actual arm's length transactions is appropriate.

8. Quality differentials generally. The MMS proposes that where crude transported to a lessee's refinery has a different gravity or a different sulfur content than the crude for which a price is published at a market center, the lessee should make an adjustment even though he has no exchange agreement or quality bank. Specifically, the MMS proposes that the lessee use appropriate posted price gravity tables to make the gravity adjustment and use a factor of 2.5 cents per one-tenth percent difference in sulfur content to make the sulfur adjustment. Proposal at 50093. Underlying the MMS sulfur proposal is an estimate that the typical sulfur content of crude produced from Federal leases is 1-3 % and that 2.5 cents per 0.1% (or 25 cents per full percent) would be similar to the factor used by the All America Pipeline. Id.

Industry believes the proposed adjustment for sulfur is grossly inadequate when applied in conjunction with quality adjustments based on gravity. For example, All American Pipeline uses a regression program to establish a "Sulfur Coefficient" for OCS crude for each delivery month, Local Tariff, All American Pipeline, issued February 18, 2000 (Attachment **A**), and historical data shows a Sulfur Coefficient range of 51 cents to 81 cents per full percent. In the Gulf of Mexico, market-based quality banks have a sulfur adjustment factor that exceed 90 cents per full percent on average and a fixed bank factor of $1.00 per full percent. *See, e.g.,* Poseidon Oil Pipeline Company web site at www. Poseidonoil.com. (Attachment **B**). *See also* the shipper-provided summary of ExxonMobil Pipeline's South Marsh Island System sulfur coefficients averaging around 90 cents for January 1997-October 2000 (Attachment **C**). Furthermore, the MMS itself has negotiated settlements for California valuations using 50 cents per full percent. In sum, there is no evidence to support anything less than a sulfur adjustment factor of 50 cents per full percent and widespread evidence to support $1.00 per full percent.

9. Lessee opt-in to indexing for certain arm's length transactions. The MMS asks whether lessees should be allowed to use indexing for oil sold at arm's length in multiple sales downstream where there is no transfer to an affiliate and tracing would be unduly burdensome. Proposal at 50096. Industry strongly supports this option. While the gross proceeds of a lessee's own arm's length sales are the best measure of the value of production, if NYMEX -- or another index -- correlates well to actual market transactions, lessees should have the option to avoid unduly burdensome tracing.

The current regulations already allow lessees who enter into exchange agreements or transfer their production to an affiliate to use indexing to value their production. § 206.102(d)(1)

& (d)(2). Given the MMS' confidence in indexing generally, it is anomalous that a lessee who engages in neither exchange agreements nor affiliate sales is denied the option to use indexing where tracing is impracticable. Allowing a lessee to opt for indexing is another opportunity to avert needless administrative costs without compromising MMS audit ability or lessee royalty accountability.

C. Transportation Costs: Specific Cost Items 30 CFR §§ 206.110 & 206.111

As it has already done with the gas valuation rule, 30 CFR § 206.157, the MMS proposes to list several specific post-production costs as either allowable or non-allowable. Proposal at 50093-50095. Industry continues to strongly support the inclusion of specific transportation costs in the regulations themselves as a powerful tool for averting avoidable disputes arising out of lack of clarity.

However, Industry urges the MMS to augment the proposed list by including at least gauging fees and scheduling fees. Gauging fees charged under a regulated tariff should be added because they are not to be confused with metering costs incurred at the lease. Gauging services are typically included in published or contract transportation rates, but when they are specified as an add-on to the tariff rate or contract rate, they are directly related to the downstream physical movement of lease production and should be an allowable deduction. Likewise, scheduling services like Oil Distribution Services (ODS) are prescribed by the transporter as necessary for physical movement of lease production through St. James terminal. This cost is charged regardless of whether lessee, lessee's purchaser, royalty owner or royalty owner's purchaser makes the movement, and is a cost directly related to downstream physical movement of lease production and imposed whether oil is sold or sent to refinery without sale. *See, e.g.,* attached Shell-Marathon letter, dated February 17, 2003, imposing the typical pipeline-shipper requirement that all companies using the pipeline secure the services of Oil Distribution Services, Inc. (ODS) to provide documentation of the quantity of barrels shipped. (Attachment **D**).

Finally, the MMS Proposal treats transportation allowances for non-arm's length transactions somewhat differently than arm's length transactions. Specifically, the Proposal would deny transportation deductions for tariffs (because lessees would not be paying tariffs to a third person but would have to calculate its actual costs) and for letters of credit (because affiliates are not likely to need them from parent producers). In addition, the Proposal would deny transportation deductions for affiliate-related quality bank administrative fees, short-term storage fees and pump over fees, all fees that an affiliate may incur and may contribute to the post-production cost of moving oil. Industry urges the MMS to eliminate differential treatment not based on the character of the service; the underlying principle should be that non-arm's length transportation costs should be deductible if they are incurred by the lessee and not already included in actual cost calculations.

D. Transportation Costs: Cost of Capital 30 CFR § 111(i)(2)

After reconsideration of its 2000 Oil Rule, the MMS "believes that a market-based cost of capital is needed to reflect accurately the actual and necessary costs to owners of transportation systems." Proposal at 50093. Specifically, the MMS proposes to retain the use of the Standard & Poor's BBB bond rate as the index of the cost of rate of return but replace the current multiplier of 1.0 with a multiplier of 1.5. Id. Citing its decision to employ a 2.0 multiplier of the BBB bond rate for the geothermal industry, the MMS posits that a multiplier of 1.5 better reflects the average rate of return in the oil industry considering both equity and debt and that a uniform rate of return is preferable to a project specific approach. Proposal at 50094.

The MMS also acknowledges receipt of a study prepared by the American Petroleum Institute (API) after promulgation of the 2000 Oil Rule.[1] The API Study is of special significance because it augments the 2000 rulemaking record by adding important new information to more fully explain several matters of central relevance to the calculation of the cost of capital. For example,

- The group of producers comprising the Department of Energy's Financial Reporting Service (FRS) companies better represented the group of companies likely to own pipelines than the company grouping relied on by the MMS in the 2000 rulemaking.

- Equity and debt financing should be weighed in examining oil pipeline construction, not merely debt financing as the 2000 rule rulemaking assumed.

- A rate of return in the 1.6-1.8 times the Standard & Poors BBB bond rate range is far more appropriate than the 1.0 multiplier challenged in the pending challenge of the 2000 rule in the pending litigation, IPAA v. Baca, Civ. No. 00-761 (D.D.C.) and API v. Baca, Civ. No. 00-887 (D.D.C.).

In the comments that follow Industry addresses the early-filed comments of Alaska and Louisiana that would resist any increase in the BBB multiplier above 1.0 at all. Industry comments then address certain reservations that the MMS has about raising the BBB multiplier above 1.5.

1. State reservations about any increase in the multiplier. Industry flatly disagrees with the Alaska and Louisiana comments contending that an increase in the BBB multiplier is not warranted because oil pipelines are low or medium risk projects. Comments of State of Alaska, undated; comments of State of Louisiana, dated September 16 at 2. While oil pipelines may not face the "dry hole" risk of drilling an exploratory well, they can face very large risks of a different character and sufficient to radically change the economics of the enterprise. Several examples drawn from different pipelines, onshore and offshore, belie the "low risk" view:

- *Amberjack* is a pipeline project where the basic investment risk materialized; pipelines do not always have a guaranteed throughput. *Amberjack* was built to attract production from the Green Canyon area of the Gulf of Mexico but had virtually no throughput in the first 12 to 18 months after it was commissioned for service.

- *Poseidon Oil Pipeline* was snagged by an anchor. Maritime law limits the liability of a vessel owner and only allows the affected party to recover the recovery to physical damages to the affected party's assets. Judgments and settlements therefore are

[1] The Proposal identifies the API Study as "BBB Bond Rate Not an Adequate Measure of Capital Cost." In the course of discussions, API did present a preliminary study, so named, but the final version presented was "Capital Cost of Pipeline Assets Used in Transporting Federal Royalty Oil: Critique of Treatment under Current MMS Oil Valuation Rule," Edward Porter, American Petroleum Institute, December 11, 2002, ("API Study") (Appendix **E**).

typically less than 100% of actual physical damages and deny the recovery of commercial losses such as lost revenue from shut-in or rerouted production, thereby imposing a high risk on pipeline owners.

- Celeron's *All American Pipeline* from Las Flores, California to McCamey, Texas, was a 30" heated and insulated line designed to carry heavy West Coast production to the Houston Ship Channel. Phase 1 of the line proved to be uneconomical and was idled; Phase II from McCamey to Houston was never built.

- *Express Pipeline* from Alberta to Casper obtained some long term producer commitments but significantly underperformed.

- The *Badami* pipeline on the North Slope of Alaska is currently not in use because of unrealized throughput expectations. Badami came on line in September 1997 with the expectation that it would transport 35,000 barrels per day from the Badami field. However, by the time the Badami field production was suspended it was producing only 1,350 barrels per day, a production rate that could not offset field operating costs and making it uneconomical.

Indeed, if pipelines were inherently low risk projects and the cost of capital for pipelines were typically lower than other petroleum operations, it would follow that pipeline companies would be routinely spun off to facilitate financing. Yet there is no evidence of that occurring. While there are a few non-producer owned pipelines, producer-owned pipelines are the norm. In addition, Alaska's claim that a selected group of oil companies enjoys returns greater than that of the TransCanada Pipeline implies nothing about the relative risk of pipelines in the petroleum sector relative to any other petroleum industry activity.

In fact, a petroleum firm engages in a mix of activities with a wide range of risk and interdependence and it is the joint distribution of potential outcomes of all these risky activities that a firm's management presents to the capital markets in seeking finance for those activities. This bundle of activities draws on the common pool of capital that the market makes available to firms with similar risk characteristics. In that sense, capital supplied by the market is fungible within the firm to a variety of activities that together determine these risk characteristics. To the extent that activities such as pipelines are financed out of this common capital pool, those activities share a common capital cost with all other activity drawing from the same capital pool. The WACC approach used in the API Study, explained in more detail below, is intended to provide an average measure of the cost to the firm of financing this bundle of activities.

2. MMS reservations about adopting the industry-proposed multiplier. As to the MMS-promoted use of a single index rather than case-by-case determinations, Industry wholeheartedly supports continuing that approach. In addition, both the MMS and Industry endorse a market-based measure of the cost of capital. What remains at issue is the magnitude of that measure.

In support of its 1.5 multiplier for the chosen BBB index, the MMS alludes to a 1.1-1.5 multiplier range arrived at by its own experts, concluding that its proposed 1.5 multiplier is reasonable because it falls within the range of its own experts and close to the range recommended by Industry experts. However, the MMS Study, "Cost of Capital for Pipelines," M. Rose, Minerals Management Service, July 2, 2003, itself has flaws that in combination lead to an understatement of the cost of capital and the corresponding multiplier:

First, the MMS Study assumes that pipeline costs are systematically lower than overall petroleum sector costs. As a consequence, it proposes that an alternate sample be used representing pipeline companies rather than petroleum extraction companies. It proposes two alternatives:

One MMS-suggested sample is an artificially constructed sector assembled by EIA. In its "Performance Profiles of Major Energy Producers" document, EIA breaks out the return on investment (ROI) of companies by upstream, downstream and pipeline segments. Citing this data, MMS observes that ROI for the listed pipeline segment is lower than the other segments, and concludes that this demonstrates the lower risk of pipelines. However, the assets DOE/EIA identified as the "pipeline segment" in the Performance Profiles only includes "Federally or state rate-regulated pipeline operations, which are included in the reporting companies consolidated financial statements,"[2] a group of pipelines narrower than the full FRS sample used in the API Study. These rate-regulated assets do not represent the pipeline segment as a whole nor represent the pipelines at issue in this rulemaking. Indeed, these rate-regulated pipelines could have been properly excluded from the larger FRS sample employed in the API Study on grounds of unrepresentativeness. Had they been so excluded and the effect of their systematic lower rate of return eliminated, the estimated WACC for the remaining sample, and the corresponding BBB multiplier, would have been even <u>higher</u> than estimated.

Another MMS-suggested sample -- and the one on which the MMS' 1.1-1.5 estimate is based -- would be derived from published Ibbotson data that represents exclusively pipeline companies. However, the MMS-suggested sample contains only <u>gas</u> pipeline companies, which do not include the assets at issue here. MMS justifies the choice with the "plausible assumption" that gas pipeline costs are representative of oil pipeline costs. In contrast, the API study uses a commonly used sample, chosen expressly to be closely representative of the population of firms actually owning the pipelines at issue and biased toward a lower multiplier.[3]

Second, the MMS Study employs an assumed tax rate rather than an observed marginal tax rate; this increases the uncertainty of the range of multiplier values. In contrast, the API study used Ibbotson's estimate of actual marginal tax rate.

Third the MMS Study computes a range of multipliers from 1.1 to 1.5, with a "likely" value of 1.3, but offers no analysis to suggest why any one of the estimates should be considered more likely than any other. Given that the observed tax rate for firms actually owning oil pipelines is toward the top of this range, and that increases in tax rate raise the estimated

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[2] Glossary at EIA web site at <u>http://www.eia.doe.gov/emeu/perfpro/glossary.html</u>.

[3] The API study, produced with the assistance of Ibbotson, considered various industry samples. The first considered was SIC 131, comprising 99 firms representing firms whose principal activity is petroleum extraction. The second was SIC 291, comprising 11 firms whose principal business is refining. Recognizing that SIC 131 probably over-represented small independent producers with few if any pipeline assets, the sample used routinely by the Department of Energy as a part of the FRS was employed. The 30 firms include in the FRS sample comprise all of the integrated oil companies as well as the largest independent producers and refiners. Because the FRS sample includes virtually all of the SIC 291 firms and the largest SIC 131 firms with pipeline assets, yet omits middle size firms with pipeline assets who are likely to have a higher Weighted Average Cost of Capital (WACC) than the FRS firms, the FRS sample has a clear and known negative bias. As a result, the Ibbotson-calculated WACC to BBB ratio (1.6) for the API Study should be viewed as the <u>floor</u> to the industry range.

WACC to BBB ratio, the more "likely" value of the multiplier in the MMS Study should be closer to the top of the estimated range (1.5) than the middle (1.3).

In contrast, while the initial analysis in the API study suggested a range of 1.6 - 1.8, subsequent analysis of FRS data confirmed that the multiplier should be at least 1.6. Moreover, the API Study includes a sensitivity analysis showing that the estimate prepared for October 2002, for either SIC 131 or SIC 291, was 4-15% lower than the average multiplier computed over a 6-year period, suggesting an average multiplier approaching 2.

In sum, the multiplier derived from the MMS study should be closer to 1.5 and the multiplier derived from the API study should be appreciably higher than 1.6. As a result, the MMS proposal of a multiplier of 1.5 is plainly too low.

3. Non-pipeline transportation. In addition, we note that the transportation allowance portions of the MMS oil valuation regulations are directed at "transportation systems" and are not limited to pipelines. This is relevant because the economics of other transportation systems (e.g., trucks, barges, tankers), while less frequently employed than pipelines, can differ markedly from pipelines and may require more individualized treatment, perhaps on a case-by-case basis.

E. Joint Operating Agreements 30 CFR § 210.5

The MMS proposes to abandon its presumption that sales to a co-lessee under a joint operating agreement are non-arm's length. Proposal at 50096. However, the MMS would limit its proposal by opining that: "In some circumstances, the sale may also be a marketing agreement, and the operator may be performing the marketing function for the lessee. In such a case, the MMS may determine that the lessee has improperly deducted marketing costs, and MMS may increase the royalty value accordingly." Id. The MMS proposal would also revise § 210.53 to prescribe certain reporting requirements where the operator under a JOA is also a designee and reports and pays royalty on behalf of one or more working interest owners:

> On the Form MMS-2014, the operator must report the following information on separate lines:
>
> (1) The share of the production the operator purchased from each working interest owner and the associated royalty payment;
>
> (2) The operator's own share of production and the associated royalty payment.

30 CFR § 210.53(c), as proposed at 68 FR 50108 (Aug. 20, 2003).

Under the existing rules and associated guidance, separate reporting is required only when the operator disposes of its own share of production by way of a different sales type than the non-operator production is disposed, i.e., the operator sells to an affiliate but the non-operator sells to a 3rd party. In this situation, the operator's share of production would be reported as "NARM" and the non-operator's share would be reported on a separate line as "ARMS."

The Proposal would require an operator under a JOA, who is also a designee and who reports and pays royalty on behalf of one or more working interest owners from whom he buys production, to report the share of the production it purchased from the working interest owners and the associated royalty payment on a separate line, even if the operator disposes of it's own share of production in an arm's-length transaction. In this example, both lines would have the sales code "ARMS," but the operator's share of the production would be reported on a separate line than the non-operator's share of production that is being purchased by the operator as designee under a JOA joint operating agreement.

Consistent with the Proposal but to avoid undue reporting, Industry recommends that § 210.53(1), as proposed, be amended to strike the phrase "each working interest owner" and be replaced with "the working interest owners." This change would conform the reporting requirement with the explanatory text in the preamble at 68 FR 50096, which seems to state clearly that the revised reporting requirement could include a second line but not more. If additional lines and/or additional codes were required to provide more specificity, the reporting burden could be extremely burdensome, necessitating extensive and costly reprogramming of computer systems to enable multiple payments to the MMS on the same property, as well as costly time-consuming manual efforts by some lessees to ascertain and break out the decimal interests of owners.

F. Other Issues

1. Grace period. The MMS proposes to end the grace period for reporting changes and paying royalties under § 206.121 on the basis that three years have now elapsed since the 2000 rules became effective. Proposal at 50096. Industry supports this change, but observes that a new grace period is important if the MMS adopts reporting changes that would involve company system modifications (e.g., in connection with the handling of joint operating agreements).

2. Renumbered benchmarks. The MMS proposes to promote clarity by renumbering the four benchmarks for valuation of non-arm's length sales in the Rocky Mountain Region under § 206.121. Proposal at 50096. Industry supports this change.

3. Definition of "affiliate." The MMS proposes to alter the definition of "affiliate" under § 206.101 by striking the phrase "of between 10 and 50 percent" and substituting the phrase "10 through 50 percent." Proposal at 50096. Industry supports this minor clarifying revision.

4. Redepreciation. In addition to the listing of allowable and non-allowable transportation deductions, the MMS also proposes a technical correction to the existing transportation deduction for redepreciation by striking the § 206.111(h)(5) phrase "who owned the system on June 1, 2000" and replacing it with "from whom you bought the system." Proposal 50095-50096. Industry supports this change.

5. Royalty value determinations. Although the royalty valuation determination process of 30 CFR § 206.107 is not at issue in this rulemaking, we urge the MMS to explore any ways to facilitate prompt turnaround of royalty valuation determination requests. We fully appreciate that the matters posed for MMS valuation determinations tends to involve uncommon sets of facts and circumstances that complicate the decision making process. However, we also understand that the MMS has received relatively few such requests since promulgation of the 2000 oil valuation rule. While a rigid timetable for MMS disposition of royalty valuations may be impracticable, reasonably prompt disposition is likely to result in substantial administrative costs savings by eliminating readjustments and fewer disputes, which redounds to the benefit of all stakeholders.

# # # # #

We urge the MMS to carefully consider our comments and welcome any further questions you might have to order to reach a satisfactory resolution of this important rulemaking.

Sincerely,

Kenneth Leonard
American Petroleum Institute

Lee Fuller
Independent Petroleum Association of America

William F. Whitsitt
Domestic Petroleum Council

Albert Modiano
U.S. Oil & Gas Association

List of Attachments

Attachment A:	Local Tariff, All American Pipeline, issued February 18, 2000.
Attachment B:	Excerpt from Poseidon Oil Pipeline web site at www.poseidonoil.com.
Attachment C:	Sulfur coefficient for period January 1997-October 2000 supplied by shipper on ExxonMobil Pipeline South Marsh Island System.
Attachment D:	Letter from Shell Pipeline to Marathon Oil Company, dated February 17, 2003, requiring Oil Distribution Services documentation.
Attachment E:	"Capital Cost of Pipeline Assets Used in Transporting Federal Royalty Oil: Critique of Treatment under Current MMS Oil Valuation Rule," Edward Porter, American Petroleum Institute, December 11, 2002.