American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005
202-682-8240

G. William Frick
Vice President and
General Counsel

July 31, 1998

David S. Guzy
Chief, Rules and Publications Staff
Minerals Management Service
Royalty Management Program
P.O. Box 25165
MS 3021 Denver, CO 80225-0165

American Petroleum Institute Comments on Minerals Management Service Further Supplementary Proposed Rule on Valuation of Crude Oil Produced on Federal Leases, 63 FR 38353 (July 16, 1998)

Dear Mr. Guzy:

API is a national trade association whose over 400 members represent all aspects of the petroleum industry. Many of our members are actively engaged in activities involving crude oil produced on federal lands and together they account for the vast majority of crude oil royalties paid every year. API has participated at every juncture in the crude oil valuation rulemaking and offers the following comments on the MMS' July 1998, supplemental proposal. Our comments also address the MMS' closely related July 24, 1998 response to the issues presented by industry at the Senate-convened meeting on July 22, 1998.

We are encouraged that the MMS has responded to the industry concerns and has agreed with our proposal to revert to the existing, control-based definition of "affiliate," rather than pursue the simplistic, ten percent formula proposed in the MMS' February 1998 proposal. However, we urge the MMS to add to that definition standards by which it is clear what showing must be made to rebut the definition's presumption of control.

In its supplemental proposal the MMS has also responded to the industry comments urging that the definition of "gathering" be reexamined in the context of subsea OCS operations where pipelines now deemed "gathering" lines often move production distances greater than the distances usually associated with "transportation" lines. Attached are API's specific comments on this important issue.

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As to the rest of the July 16, 1998, proposal, and the separate July 24, 1998 response paper, we see no MMS movement toward resolution of the basic flaw in the rulemaking. Notwithstanding the most recent proposal's discussions of breach of duty to market and exchanges, nothing in the supplemental proposal addresses the MMS' flawed inclination to move the starting point for valuation downstream. Moreover, the response paper makes it clear that the MMS is wedded to a downstream valuation approach.

As API's earlier comments show, this downstream, netback orientation would require the lessee the obligation to collect voluminous data and maneuver through a maze of unduly complex and and vague requirements. It would require lessees to engage in extensive downstream tracking which is unduly burdensome and, in some cases, impossible to accomplish given the practical problems posed by the multiple exchanges and commingling that regularly occurs in the crude oil marketplace. Nowhere has the MMS even acknowledged the extra burden and uncertainty created by these downstream-oriented requirements, let alone attempted to ameliorate or even clarify them. Although the Office of Management and Budget has understood these concerns and twice rejected the MMS' proposed Form 4415, the MMS has basically ignored industry comments.

More fundamental, a downstream valuation approach -- whether it turns on the use of gross proceeds of downstream sales or the use of crude oil spot prices as an index – cannot lead to the proper value for royalty purposes unless coupled with adequate adjustments for the many factors that can add downstream value. Under the terms of applicable mineral leasing statutes and leases, royalty is due on the "value of production" at the lease; a netback-type approach with inadequate adjustments simply cannot arrive at the value of production at the lease.

Yet, the MMS' supplemental proposal and response paper simply reject out of hand the use of <u>any</u> benchmark approach for the non-arm's length situation, except for the geographically and functionally limited approach offered for the Rocky Mountain region. Throughout the rulemaking, MMS has professed to invite alternatives but continues to reject concepts, such as tendering programs, royalty in kind, and others.

For example, the MMS rejects a menu approach because of its concern that industry will game the system and always choose the method which arrives at the lowest value. Yet in fact the industry proposal suggests a process that would let MMS preclude gaming: a lessee would notify the MMS in advance, commit to temporal or geographic limitations, and identify backup measures if the first choice were not practicable or acceptable.

Likewise, the MMS rejects tendering even though several companies have well-established tendering programs which yield values very much in line with prices paid by other purchases of crude oil at the lease. Despite MMS' criticisms, tendering cannot be more complex than indexing because it makes the data intensive review of transportation allowances and quality differentials wholly unnecessary.

Rather than improve the present regulations for valuation of crude oil, the MMS has from the outset of this rulemaking clung to its initial belief that a novel, downstream indexing approach was needed. And it bases that conclusion on the palpably erroneous assumption that there exists no market at the lease, despite contrary evidence in the administrative record and testimony before Congress.

Starting point for valuation aside, the MMS has been no less intransigent on the overall adjustments side of the rulemaking. Beyond limited adjustments for quality and location, the MMS continues to reject any discussion of adjustments claiming that the duty to market free of charge to the lessor is "long and clearly established law." Industry simply disagrees with the erroneous and misleading characterization of the law and the pending litigation in the United States District Court for the District of Columbia may require a court to resolve this core issue. With respect to transportation allowances alone, MMS claims that very small volumes of oil are moved at arm's length are flatly wrong. For example, in the Gulf of Mexico one large producer estimates that it transports close to fifty percent third party non-lessee oil.

And finally, although we are encouraged that MMS has indicated that the Assistant Secretary may make binding valuation determinations, it is necessary to establish a process by which companies trying to comply can obtain binding valuation determinations in a timely manner.

In sum, the July 1998 proposal fails to cure the flaws with the February 1998 proposal and fails to satisfy the MMS' own claims. It neither simplifies the valuation process nor reduces the cost of compliance. It offers no real certainty and no real prospect of reduced controversy. And it does not lead to royalty obligations based on the value of production at the lease. Again, we urge you to reassess the direction of this rulemaking and consider additional meetings among technical staff to address the key unresolved issues: applicability of arm's length contracts to multiple exchange situations; use of benchmarks anywhere in the country, including use of tendering and comparable arm's length transactions; appropriate transportation allowances; clarification and simplification of valuation requirements; and a process for issuing binding valuation determinations.

Sincerely,

G William Frick

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Vice President, General Counsel
and Secretary

Attachment

Gathering v. Transportation

Subsea Development

Subsea development is a new technology for producing oil and gas on the OCS comprising wells completed on the sea floor on a lease or unit. Production from these wells runs back to a centrally-located subsea manifold also located on the sea floor. It replaces the traditional fixed structure above the surface as the central receipt point of production from various wells on the lease or unit. Production from various subsea wells then flows through a pipeline to a surface location at a platform located many miles away from the unit or lease where the subsea manifold is located. For example, one operator's gas production moves 63 miles to a platform located in shallower water on the OCS. At this platform, the production is then treated and placed into another transportation line and moved to shore with other production.

Basic Question: Gathering v. Transportation

The July 1998 supplemental proposal asks whether this movement of great distance from one subsea manifold to the surface platform should be classified as gathering or transportation. The MMS' existing regulations were conceived and drafted to address an OCS development scheme based on the concept of multiple wells or multiple platforms on a single lease or unit in which production was gathered to a central surface facility located on the lease or unit. Under this surface model, production is generally treated at this central facility platform located on or immediately adjacent to the lease or unit. After treatment, the production is delivered into a pipeline and moved to shore. However, subsea technology has surpassed this limited model of offshore development. MMS needs to take into account technology advances by updating its rules to characterize subsea movement off the lease or unit as the transportation that it is.

Every issue of transportation for royalty allowance purposes requires a two-step analysis: First, what activity is encompassed by transportation? Second, what is the amount of the transportation allowance?

1. What activity is encompassed by transportation?

Over the years, the MMS' interpretation of what falls into the category of transportation has been fluid. Among the relevant factors MMS has considered are movement off the lease/unit, physical characteristics of production, movement before or after the royalty measurement point, purpose of the movement (e.g., to move toward sale), and location of the sales point. Over the years, differing weights have been assigned to these factors. For example, on the West Coast, the MMS has tended to favor production handling and treatment onshore and has approved transportation to shore of raw production, recognizing the movement and the value of the transportation provided. In the Gulf of

Mexico, the MMS has recognized transportation of bulk raw production from multiple leases to a central onshore treatment facility as transportation for allowance purposes.

When subsea systems are utilized as the primary development system for lease/unit development, the treatment of subsea production to achieve pipeline quality may be impossible at the lease/unit. Subsea systems, by their very nature, do not allow separation and delivery of production on the lease because of the absence of surface facilities. The common thread running through almost every transportation allowance characterization is physical movement of the hydrocarbon off the lease or unit. In subsea development, the central fact is that production is physically moved at a great cost over large distances nearer to shore to a point where it is more valuable and more easily sold. The selection of subsea systems for lease/unit development is principally driven by economics. In most instances, lease/unit development would not have been economic utilizing a platform type development. Consequently, the royalty settlement point is at a remotely located surface platform because it is more technically practical and economically feasible. If a surface platform type system were utilized for lease/unit development, movement of production away from the lease would clearly be deemed transportation. The fact that a different development system was utilized for economic reasons should therefore not preclude production movement away from the lease/unit from being deemed transportation in subsea development situations.

2. What is the amount of the transportation allowance?

In every subsea transportation case a valuable service is being performed. Production is moved a great distance toward market and that movement off the lease merits a fair value for the transportation provided. In calculating that value, FERC classification of jurisdictional transportation versus gathering is irrelevant. Jurisdictional statutes, such as the Natural Gas Act, Interstate Commerce Act and the Natural Gas Pipeline Safety Act have specific statutory criteria for furthering their statutory goals. These acts focus on jurisdiction over the lines for certain specified public access purposes such as maximum rates and equal access and treatment. Their purpose is not to define whether movement has taken place and is a service adding value to the mineral for mineral royalty allowance purposes, but rather rate making and public access.

In the federal royalty context, mineral lessees are focusing on transportation in order to receive a fair return on the service provided for which the lessor benefits. Allowing lessees to receive as a transportation deduction the commerical value for the service provided is all that lessees seek. This approach avoids the whole controversy over jurisdiction. It resolves all jurisdictional controversy by allowing value paid by non-affiliated parties in the same field or area to be the allowance of the lessee pipeline owner. If the value of the service is valid for the non-affiliated third party, it should be valid for the lessee. Such an approach avoids the problem of MMS interpreting FERC or DOT jurisdiction issues in order to determine royalty allowances for transportation. When no actual third party production is moved through a lessee-owned line, MMS should use the value of similar services provided by a non-affiliated party in the same field or area to determine the correct allowance. If MMS limits transportation cost allowances to variable costs plus a return on non-depreciated capital equivalent to the return on BBB bonds, the MMS will be receiving an implicit subsidy. Since the return on BBB bonds is significantly less than the cost of capital for a pipeline, the allowances will be less than the actual cost of providing that transportation.

In sum, the MMS should not limit subsea transportation allowances to the cost of capital recovery but should peg the amount at the commercial value of the service.