ipaa
America's Oil & Gas Producers

October 31, 1997

BY FACSIMILE (303) 231-3194 AND FIRST-CLASS MAIL

Mr. David S. Guzy
Chief, Rules and Publications Staff
Minerals Management Service
Royalty Management Program
Post Office Box 25165
MS 3101
Denver, CO 80225-0165

Re: Response to Notice, 62 Fed. Reg. 49460 (Sept. 22, 1997)

Dear Mr. Guzy:

The Independent Petroleum Association of America ("IPAA") is pleased to respond to the request of the Minerals Management Service ("MMS") for comments on additional alternatives of the valuation of crude oil produced from federal leases. IPAA participated in all of the workshops except California[1] which MMS conducted during the last month. In part, these comments respond to suggestions and criticisms made by state and federal participants in those workshops on the revised lease market benchmarks which IPAA had jointly proposed with the Domestic Petroleum Council. In part, these comments respond to alternatives advanced by the state participants. In sum, however, nothing raised in MMS's notice or in the workshops alters our conclusion that the most efficient means for MMS to address its concerns over its current valuation system is for the agency to take all its royalty in kind.

IPAA particularly wishes to thank MMS for holding the series of workshops during October. They provided an invaluable opportunity for MMS officials, state representatives, and producers to share perspectives and understand positions better. IPAA

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[1] The MMS should separately focus on unique California concerns and not attempt to impose nationwide any valuation rules designed to address those state-specific concerns. Nonetheless, IPAA strongly supports the continued use of gross proceeds valuation for arms-length transactions for California production.

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found most state representatives open to innovation and willing to work with independent producers to find alternative methods of royalty valuation without the onerous burdens of the January 1997 proposed rule. Through those workshops, regrettably too brief, our representatives found some basis for hope that the rulemaking might be resolved through compromise and consensus. That is the result desired by the Congress, as reflected in the statement of the managers of the Interior Appropriations bill.

As a result of its participation in these workshops, IPAA has further modified its proposal to address the additional concerns raised as to the valuation of non-arm's-length sales. Its position on arm's-length sales, however, retains its original precision: it is imperative that any rule value the production of independent producers which is sold at arm's length at the lease by using nothing other than the lessee's gross proceeds. IPAA's members are unalterably opposed to any MMS effort to game this fundamental principle. No newly-minted "duty to market," no pretense that the purchase of crude oil renders an arm's-length sale "suspect," and no restriction on the number of arm's-length exchanges and calls a lessee may enter into will go unlitigated. The presence of any of these positions in a final rule will assure IPAA's forceful opposition, whatever progress MMS may make on other issues.

ROYALTY VALUE PROCEDURES FOR NON-ARM'S-LENGTH SALES

IPAA's survey indicates that its members, both large and small, have marketing affiliates. Consequently, these are real issues of great concern to the Association's members. IPAA members with affiliates believe MMS should look to their arm's-length activity for royalty valuation purposes and not subject them to arbitrary valuation schemes like NYMEX.

IPAA'S PROPOSAL

In our comments on August 1, 1997, IPAA recommended that non-arm's-length transactions be judged under a revised system of five benchmarks. During the workshops, we listened carefully to the objections and concerns expressed by MMS and state representatives. Our proposal had attempted to emphasize information readily available to the lessee and easily audited by the MMS as a basis for valuing non-arm's length sales; and with only two notable exceptions, MMS affirmed that the major components of the proposal were feasible. There was no real disagreement on how to define what constitutes a "field" or "area"[2] or on how to determine whether oil is of "like quality." We heard no serious dispute that in a given market there typically would be a range of prices for similar oil. To address the concerns of some representatives that this concept would allow companies to value non-arm's-length sales using the lowest arm's-length price in the range, however, IPAA suggested that a lessee selling under a non-arm's-length arrangement would pay royalties based on the weighted average price of arm's-length sales in the field or area.

Three points blocked full consensus, however. The first was MMS's objection that it is too difficult to find "comparable" sales of crude oil from the same field or area. The second was what MMS called the "captive market" scenario, as we will describe more fully below. The third was MMS's concern that reliance on lease market information required auditing. We will discuss each objection and how our modified proposal will address it.

MMS'S APPROACH TO COMPARABILITY IS TOO RESTRICTIVE

The basic idea behind any valuation system is, of course, that a given sale at arm's length is sufficiently similar to one not at arm's length to allow the prices to be compared fairly. During the workshops, MMS's objection centered on sales of oil of dissimilar volumes. For example, MMS objected that a tendering program offering only 10 percent of the lessee's oil sales made under that program not comparable to the lessee's sale of the remaining 90 percent to its affiliate. In fact, even where a lessee sells 50 percent of its production to (for example) four third parties, MMS rejected the notion that those sales were comparable to the lessee's sale of the remaining half to its affiliate, because the arm's-length sales were actually four separate sales of (for example) 5 percent, 10 percent, 15 percent, and 20 percent. Because no one of those four sales was of half the volume, none are comparable to the non-arm's-length sale.

In light of the history of MMS's use of benchmarks and the evolution of the current proposal, the agency's decision to raise this objection is unsupportable. Just nine months ago, MMS proposed to dramatically overhaul its royalty valuation program by using NYMEX prices -- prices bid on a contract for the future delivery of 1,000 barrels of oil.

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2 A "field" is a well-established concept for both onshore and offshore leases. While an "area" is conceptually less precise, MMS could achieve precision by using its extensive list of aggregation points, *see* 62 Fed. Reg. 3759-63, 36033-37, as the method of defining areas. For example, an area might include all of the fields shipping to an initial aggregation point.

MMS never suggested that the NYMEX price might be unacceptable because it was for a futures contract for 1,000 barrels of oil and therefore not comparable to the vast majority of sales in the lease market. Similarly, MMS continues to explore the use of spot market assessments in trade publications as a basis for royalty valuation; but those assessments are derived from transactions of unknown volumes. (Please see the affidavit of Marshall Thomas ¶¶ 58-68, filed in the rulemaking record on May 27, 1997.) And while MMS's current valuation rule requires that transactions used under the benchmarks involve "significant quantities" of oil, MMS has never maintained that the quantities must be identical to those sold not at arm's length. In short, MMS's recent concern about comparable volumes is not based on a principle consistently applied to all the options MMS is currently considering.[3]

For example, from the workshops it was apparent that MMS is receptive to the use of lease market benchmarks in the region of the Rockies, and properly so. There are many arm's-length sales of crude oil from federal leases there. But MMS's receptivity to lease market benchmarks in the Rockies is, unfortunately, not born of a confidence in the lease market, but rather of a despair over the unavailability of reliable spot-market indices in that region. And even though MMS continues to ask IPAA and other associations for market indicators, we are aware of none in the Rockies. For that reason, despite the undeniable existence of significant arm's-length sales in the lease market in the Gulf of Mexico, MMS was reluctant to discuss benchmarks for that region because of its greater confidence in the index prices at Empire and St. James, Louisiana.

While IPAA continues to believe that the issue of comparable volumes is one that can be resolved in a manner that is both theoretically and practically sound, MMS must recognize that it is difficult for a trade association with over 5,500 members to propose a resolution during a 30-day comment period to an agency that has indicated its reluctance to explore the matter. While we study the question in anticipation of the agency's next proposed rule, our proposal addresses it in the same way the Department addressed it from 1920 to 1988. During those 68 years, if the oil was otherwise of similar legal and physical

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[3] The MMS's new approach to comparability is also at odds with IBLA precedent. Indeed, when using comparable arm's length sales to value production sold not at arm's length, the Board has not deemed the volume of the arm's-length sale to even be relevant. *See, e.g., Transco Exploration Co.*, 110 IBLA 282 (1989); *Getty Oil Co.*, 51 IBLA 47 (1980). *See also, e.g., Shell Western E&P, Inc.*, 112 IBLA 394 (1990) and *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164 (1990).

characteristics, the volume of the arm's-length sale was unimportant.

In keeping with this historically-accepted approach, IPAA is forwarding a modified valuation proposal. That proposal provides for the lessee to choose among three royalty value procedures, or RVPs, for a certain period of time. (Attachment 1 outlines and illustrates the RVPs.)

- First, outright sales of significant quantities of like-quality crude in the field or area, including sales under "tendering" programs.
- Second, arm's-length purchases of significant quantities of like-quality crude in the field or area.
- Third, netback methodology using an indexed price or an affiliate's resale price minus all actual costs for transportation and value added by midstream activities (see attachment).[4]

The issue of comparable volumes is relevant only to the first two RVPs. Under IPAA's proposal outright sales or purchases of like-quality oil by the lessee or its affiliate at arm's length may be used only where a "significant quantity"of the lessee's oil is sold or purchased in the field or area at arm's length. To be a significant quantity, the volume must exceed a given percentage of the lessee's working interest share of production in the field or area in the given production month. The percentage to be selected should be greater than the standard royalty rate for either onshore or offshore federal leases. A limited percentage higher than the standard royalty rate should dispel any doubt in MMS's mind, for no lessee would undervalue, say, one-fifth of its own oil simply to reduce the value correspondingly on the one-sixth or one-eighth royalty share of its oil. Yet the percentage obviously cannot be the 50 percent in a single transaction, as suggested by MMS representatives at the workshops. Given the agency's longstanding position that the volume of oil sold was largely irrelevant, it is indefensible for MMS to argue that a producer should not be allowed to value 48 percent of its production, sold not at arm's length, by using prices received from the sales of 52 percent of their production in two or more arm's length transactions.

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4 IPAA was encouraged by the willingness of the representatives from states to use actual transaction data from producers engaged in the midstream market. This, along with the adoption of IPAA's royalty value procedures, would permit the agency to scrap its inordinately expensive and largely useless proposed Form 4415.

THE CAPTIVE MARKET SCENARIO

During the workshops, MMS and state representatives frequently referred to what they called the problem of the "captive market." Under this alleged captive market scenario, a company operates a remote field and controls the only pipeline from it. It owns the dominant share of the lease interests in the field (say, 90 percent), purchases all the production owned by third parties, and ships all the field's production to its affiliate's refinery. To some extent, the representatives argued, the company can effectively set its posted price for purchasing oil in the field without pressure from competing buyers. No representative suggested that "captive markets" of this sort occur more than infrequently; yet the problem was offered as the leading illustration of why MMS's current regulatory benchmarks and IPAA's August proposal are unworkable.

Under our modified proposal, MMS would not need to struggle over how to define what a "captive market" is. RVPs 1 and 2 limit the use of arm's-length transactions to lessees selling or purchasing "significant quantities" of oil at arm's length. Our proposal would define "significant quantities" at a level high enough that lessees who held a particular field "captive" would generally not qualify. As the captive market scenario was described at the workshops, those lessees are companies which would not ultimately resell the oil, so the only RVP they would qualify for would be a netback method using an index price. In sum, IPAA's proposal permits MMS to deny the use of lease market value procedures in those situations MMS finds suspect; yet does not drag down the rest of the industry selling in competitive fields and areas.

TIMELINESS OF INFORMATION AND AUDIT BURDEN

During the workshops MMS representatives repeatedly stressed their interest in a valuation system less dependent on auditing than the current system is. Accordingly, MMS asked IPAA to explain how IPAA's August benchmarks could be verified without auditing and how lessees could have the information needed to employ the RVPs in time to pay royalties at the end of the month following the month the oil is produced.

Before explaining how IPAA's royalty value procedures address that concern, IPAA believes it important for MMS to keep these questions in perspective. Reducing the burden of audit is a worthwhile goal, but it is not the most important goal under federal statute. There is a balancing to be done between reducing audit burden and satisfying the statutory duty to receive market value at the lease within some acceptable range of accuracy. At one end of the spectrum, MMS could simply set a single national royalty value to be used in the following month of production. Auditing would be virtually eliminated, but that single national value would be significantly wrong in a large number of fields as a measure of market value at the lease. At the other end of the spectrum, the agency could determine *post hoc* the value in each field after auditing all parties' arm's-length sales in the given field and deriving the market value or values. That approach would provide a very accurate picture of market value at the lease, but would require auditing *ad nauseam*. In sum, it is certainly fair for MMS to inquire about the impact of any valuation proposal on auditing needs. But it is unfair to suggest, as MMS did at the workshops, that value procedures based on lease market information are unacceptable because some auditing may be required.

IPAA has structured its modified proposal to emphasize the use of information already in the lessee's possession. Circumstances will vary, of course, from one lessee to another and from field to field for the same lessee; what is readily at hand for one may not be so for the next. Therefore, IPAA recommends that a lessee be permitted to elect which RVP to use. The election should be prospective and should be binding for some sufficient period of time to allay MMS's concerns that the lessee would attempt to "cherry pick" procedures to its best advantage. Whether a lessee could make the election by field or area, which IPAA finds preferable, or would have to make the election nationwide would depend in part on MMS's information system needs and limitations. But that is an issue IPAA is prepared to discuss further with MMS and state representatives.

MMS itself can ease the audit burden by redesigning its audit strategy to focus on field audits instead of company-wide audits. This is a strategy the agency could appropriately have followed from the outset, given the emphasis in the royalty value rules even before 1988 on prices in the same field or area. More importantly, it is a change IPAA understands the agency is undertaking anyway, so the agency's audit strategy is essentially ready to accommodate the RVPs IPAA proposes.

Finally, IPAA proposes that MMS use its current system with some software revisions to permit its auditors to perform "contemporaneous desk checks." The desk check strategy, explained in Attachment 1, will increase the agency's confidence that payments are accurate without the need to perform extensive auditing, and will better focus those fewer audits that will be needed. To implement this strategy, IPAA proposes simple changes to the Form MMS-2014. With these changes, MMS could analyze values being paid in the given field using data straight off MMS's system. Anomalies could then be targeted for verification through more thorough audit methods.

DEDUCTION OF MIDSTREAM BENEFITS FROM ROYALTY VALUE

A source of special frustration for IPAA members is MMS's refusal to discuss the issue of the alleged "duty to market." IPAA has previously explained that many of its members have formed affiliates to handle the additional risks and costs assumed when a producer's affiliate moves oil downstream from the lease. Under both the proposed "duty to market" and the proposal to begin valuing royalties with the price received when the affiliate resells the oil, MMS would claim royalty on the value added by taking those risks and paying those costs, but without any risk to itself or cost other than a limited allowance for transportation costs.

State representatives at the workshops thought deducting the value of midstream activities was appropriate. MMS, however, refused to consider the topic, asserting that such a deduction would be contrary to the lessee's duty to market production. But IPAA has already documented that there has never been an express or implied "duty to market" crude oil. Even as to natural gas, the "duty to market" recognized by the IBLA has not extended to costs and benefits unique to midstream activities.

For IPAA members selling oil at the lease at arm's length, the duty to market prevents a lessee from relying on its gross proceeds as the value of production and subjects the lessee to after-the-fact second-guessing about its marketing decisions by MMS during audit.[5] For members selling to affiliates which engage in midstream activities, the duty to market is simply an effort to tax the value added by a separate line of business downstream from the lease.

The true measure of value added or lost in the midstream market is the difference between the market value of the oil at the lease and the market value of the oil at the point of resale, for different forces of supply and demand are present at each location. For these reasons, the superior method of valuing royalties from non-arm's-length transactions is the RVP system IPAA has proposed. RVPs 1 and 2 directly measure the

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[5] During one of the workshops, an MMS representative insisted that the duty to market would not be used to second-guess the value paid by a lessee governed by the gross proceeds standard. If that is the agency's intent, then it must be expressly stated in the regulation, because current MMS policy is to attempt to apply the duty even to arm's-length sales. *Amerac Energy Corp.*, MMS-93-0868-OCS (1996), *on appeal*, IBLA 97-118. But even this clarification would not fully respond to IPAA's concerns.

value of oil at the lease.

If, however, MMS is going to continue considering affiliate resale prices in royalty computation, it must address the issue of midstream marketing. Some of the costs can easily be subsumed under MMS's traditional deduction for transportation, but the rules on transportation allowances will require clarification and amendment. Additional provisions will be needed to address other costs as well as the value added by midstream risk-taking. During the workshops, IPAA provided illustrations (see Proposal, Attachment) of what a portion of those costs would amount to when expressed in a cents-per-barrel basis, but those illustrations did not attempt to address all out-of-pocket costs incurred in the midstream market, let alone address any of the value added by risk-taking. Plainly, more dialog is needed to resolve this flaw in the agency's proposal.

NON-COMPETITIVE CRUDE OIL CALLS

During the workshops, a state representative proposed that if a producer had to provide oil under an exercised "non-competitive" crude oil call, it could avoid being placed in the NYMEX scheme if it showed that it tried to obtain other offers for the called-upon oil but could not beat the price reflected in the call.

IPAA appreciates the effort of the representative to try to limit the occasions in which an IPAA member would be subjected to the NYMEX scheme, but after careful consideration we are unable to support this proposal in full. Not every producer will be able to seek competing offers to buy oil which he is already legally obligated to provide to the callor. For those who can, the proposal has merit. However, a call is little different than a long-term sales contract, and MMS is not suggesting that a producer selling oil at arm's length under a long-term sales contract needs to seek "competing" bids during the contract's term in order to validate its reliability continuously. Instead, absent a showing that the producer accepted a lower than market price in exchange for up-front consideration, the price received should be accepted like any other long-term price. At most, if the agency insists on treating the exercise of a non-competitive call as a suspect transactions, it should require no more of the lessee than that he should compare the call price with prices he receives under other sales from leases in the field or area. Based on our survey results, these exercised non-competitive calls, of which there appear to be very few, nevertheless still exist and we would hope MMS would adopt this approach in lieu of a database comprised of theoretical values.

Multiple Exchanges

Independent producers selling production frequently need to engage in more than one arm's-length exchange agreement to best position their oil. IPAA's view remains that it is irrational to place independent producers into the NYMEX valuation scheme if a lessee enters into more than one exchange with respect to a given barrel of crude oil. We therefore have proposed that the lessee be given the choice of using lease market RVPs or using the price it receives from the ultimate sale of the oil it has received under the series of exchanges, and netting out from that price the differentials in the exchange agreements to derive the value of the oil at the lease. Virtually all state representatives concurred with the netting approach.

Results of Membership Survey

At MMS's request, IPAA conducted a survey of its membership. The questions and typical responses are as follow:

Q: Does your company have federal leases containing non-competitive calls (*e.g.* Based on posting) which are exercised? If so, approximately how many leases are involved and what is their general geographic location?

A: Any member may have non-competitive calls, but where they exist they are few.

Q: Do these types of non-competitive exercise calls prevent you from seeking other competitive prices?

A: These particular calls do not prevent member companies from seeking other markets for competitive pricing.

Q: Is there a date by which these types of calls were no longer used in your leasing transactions?

A: While members are certainly seeing fewer and fewer non-competitive calls in sales or farmout transactions, there have been occasions on which members have been forced to execute lease agreements which contained a non-competitive call if the company wanted to complete the transaction.

Q: Does your company have a marketing affiliate?

A: Many members, both small and large, have marketing affiliates. But given time constraints, we cannot yet quantify the exact percentage. However, for independent offshore producers it appears that there are significant numbers of independents who have marketing affiliates.

Q: Does your affiliate generally incur actual costs between the well and market centers?

A: Yes.

CONCLUSION

MMS is to be commended for holding workshops to facilitate discussion, understanding, and -- if the participants are willing to persevere -- consensus on how to address the current concerns over oil valuation. We appreciate the states' representatives' willingness to consider alternatives to the MMS's NYMEX proposal and are hopeful that a consensus will be reached. Should you have any questions or desire to discuss the issues in more detail, please do not hesitate to call me or Ben Dillon at IPAA's office.

Sincerely,

Roy W. Willis

Roy W. Willis
Acting President

DC6367

IPAA's Modified Valuation Proposal - Attachment

MIDSTREAM ACTIVITIES

Marketing
- Aggregating Volumes for Barrel Availability
- Satisfying Specialized Customer Quality Preferences
- Scheduling Monthly Crude Business through Contracted Companies and Pipelines
- Crude Movement Flow Schedule for Accounting
- Review Financial Analysis of Trades
- Review of Contracts and Other Marketing Arrangements vs. Current Markets
- Development of Monthly Market Differentials
- Obtain and Analyze Crude Oil Samples

Operations
- Contracting for or Providing Transportation
- Scheduling of Volumes
- Providing Pipeline Fill
- Tracking Volumes Delivered
- Providing Credit Services
- Constructing or Leasing Storage Facilities
- Scheduling Storage Volumes
- Maintaining Inventory
- Environmental and Safety Compliance

Risk Management
- Dealing with Price Fluctuations at or Upstream of Market Centers
- Risk or Loss of Pipeline Volumes
- Environmental Liabilities for Spills
- Risk of Purchasers' Default

Administration
- Contract Preparation and Follow through with Outside Company
- Contract Maintenance
- Royalty Bonus Development and Application
- MMS and Royalty Compliance
- Oil Price Development
- Inventory Reconciliation
- Disbursement Activities (Division Order, Tax, Legal)

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IPAA's Modified Valuation Proposal

I. If outright arm's-length sale - gross proceeds

II. If non-arm's-length sale - lessee will elect one of the following royalty value procedures (RVP) for a given period of time

RVP 1 - Outright sales of significant quantities of like-quality crude in the field or area, including sales under "tendering" programs

RVP 2 - Arm's-length purchases of significant quantities of like-quality crude in the field or area

RVP 3 - Netback methodology using an indexed price or an affiliate's resale price minus all actual costs for transportation and value added by midstream activities (see attachment)

* A 4th RVP could be outright sales at arm's length by third parties in the field or area once the trade press begins routinely to publish price data for the given field.

* A 5th RVP could be prices published by MMS based on its RIK sales once MMS begins pricing royalty in kind oil independently of MMS-2014 data.

III. Form MMS-2014 revised to include two new data fields

A. Numeric code for crude oil quality designation, *e.g.*, Louisiana Light Sweet, West Texas Sour, Altamont Yellow Wax

B. API gravity (already on 2014)

C. Code indicating if lessee paid on gross proceeds or which RVP had been selected

IV. Requirements

A. RVP Election - To allow the lessee to use the least burdensome method given its situation in a given field, the lessee could elect which RVP to use for each field. The lessee must give MMS prior notice of the election. To address concerns about gaming the system, the election would be binding. Once elected, the RVP would remain in force for some commercially reasonable period of time (set out in the rule). The lessee could change the election at the end of that period upon notice, but could not do so during that period without MMS's permission.

B. Field or area - "Field" is well recognized/understood concept. "Area" could be defined by using MMS's aggregation points (such as all the fields connected by pipeline or truck route to an initial aggregation point) or the areas identified during the REGNEG process.

C. Significant quantity - A percentage which would cover the royalty percentage plus a limited amount of the lessee's equity production.

D. Lessee would be required to keep records in accordance with an MMS checklist to support any price used under the RVPs. These checklists would be forwarded to MMS on request for a *contemporaneous desk check* (see below) and/or kept on file for reference during an *audit*.

1. Contract number
2. Parties to contract
3. Contract date and period
4. Price basis
5. Volume sold or purchased

<u>If RVP 1 or 2</u>

6. Volume weighted average price for the month - All crude sold or purchased during the month (regardless of term) would be included in the weighted average calculation. This would preclude both MMS and the lessees from cherry-picking which sales or purchases to include in the calculation.
7. Lessee's total production from field or area

<u>If RVP 3</u>

8. Index price used or if resale, data on resale contract as in 1-5 above.
9. Deductions from index pricing point or point of resale: itemized (*e.g.*, location differential, transportation cost, and other actual midstream costs) and basis summarized.

III. Verification by MMS

Contemporaneous Desk Check - Goal is to permit MMS field auditors (including resident auditors at larger payors) to receive data summaries by field, prepared in Lakewood from Form MMS-2014, for cross-checking against the checklist (submitted on request). Sitting at their desks, they would have enough information to spot royalty value anomalies in the given field.

A. Using outright arm's-length sales reported on the 2014, MMS would calculate a range of prices for each field/area on a periodic (monthly, quarterly, etc.) basis.

B. MMS would compare the prices paid under the RVPs to the range of prices received under arm's-length sales and generate an analysis identifying prices which appear to be low (that is, significantly below the mid-point of the range).

C. MMS would send the analysis to the field auditor(s). Familiar with the market in the field or area, the auditor would determine whether further inquiry was warranted. If so, the auditor would ask the lessee to submit the relevant checklist (the reports described in II.D above).

D. The lessee would send MMS a copy of the checklist.

E. MMS would review the checklist. If the information provided was satisfactory, MMS would close its inquiry subject to later audit. If not, MMS would pursue the matter through audit.

The use of the contemporaneous desk check should significantly improve MMS's ability to target its audit activities, reducing total administrative costs to federal and state treasuries and to lessees. It would also speed the identification and collection of underpaid royalties, serving the goals of FOGRMA and FOGRSFA.

Example 1

Lessee does not sell its production from the federal lease on an arm's-length basis. However, it does sell crude from other leases in the field or area under three different contracts.

Lessee's Gross Working Interest volume from the field/area where federal lease is located: 1,000 barrels

Lessee's production from the federal lease: 125 barrels of Louisiana Light Sweet (LLS), 38.5 degrees API gravity

Lessee's production from leases in the field or area sold under arm's-length contracts:

1) Sold 150 barrels LLS (39 degrees) under a six-month contract to Purchaser 1 at $20.00 per barrel for 40-degree oil minimum, less $.02 for gravity adjustment.
2) Sold 25 barrels LLS (41 degrees) under a spot contract to Purchaser 2 at $20.50 per barrel for 40-degree oil minimum, no gravity adjustment.
3) Sold 50 barrels LLS (37 degrees) under a spot contract to Purchaser 3 at $20.25 per barrel for 40-degree minimum, less $.06 gravity adjustment.

Total sold under arm's-length contracts are 225 barrels. Since 225 is 22.5% of the lessee's production from the field/area, it is assumed for this example to be a significant quantity under RVP 1. Under RVP 1, lessee would use the weighted average price of its arm's-length sales to value the 125 barrels from the federal lease.

Calculation of royalty price for sales of 40-degree minimum oil:

150 X $20.00 = $3,000.00
25 X $20.50 = $ 512.50
50 X $20.25 = $1,012.50
$4,525.00 / 225 = $20.11= Royalty price for 40-degree oil.

Less gravity adjustment ($.02 per degree or fraction thereof) for 38.5-degree oil:
$20.11 - $.04 = $20.07 per barrel royalty value under RVP 1.

Example 2

Leesee does not sell its production from the federal lease on an arm's length basis. Its marketing affiliate does purchase its crude and the crude oil of the other producers from its leases in the field or area under different contracts.

Leesee's Gross Working Interest volume from the field where the federal lease is located: 900 barrels of Wyoming General Sour, 24 degrees API gravity.

Affiliate's purchase from leases in the field or area purchased under arm's-length contracts:

1. 1,458 barrels of Wyoming General Sour, 27 degrees API gravity.

2. 225 barrels of Wyoming General Sour, 27 degrees API gravity.

Total purchases by the affiliate are 1,683 barrels. The non-arm's-length purchase by the affiliate amounts to 31% of the total volume purchased. This amount would be more than adequate to satisfy as a significant quantity and the crude types are sufficiently similar so that Leesee's royalty payment to the MMS could be calculated utilizing RVP2.

Calculation of the royalty price for sales of 40 degree API gravity Wyoming General Sour crude would yield:

1458 X $16.875 =	$24,603.75
225 X $16.725 =	$ 3,763.12
Total	$28,366.87
Weighted average price	$ 16.85
Less gravity adjustment of $2.16 per barrel	$ 14.69

Royalty payment to the MMS on the 900 barrels would be based upon the price of $14.69 per barrel.

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