DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 206

RIN 1010–AC09

Establishing Oil Value for Royalty Due on Federal Leases

AGENCY: Minerals Management Service, Interior.

ACTION: Final rule.

SUMMARY: The Minerals Management Service (MMS) is amending its regulations regarding valuation, for royalty purposes, of crude oil produced from Federal leases. MMS is changing the way that oil not sold under an arm's-length contract is valued; providing optional ways for lessees to value their crude oil production if they sell it at arm's length following one or more arm's-length exchanges or one or more transfers between affiliates; changing the way that actual transportation costs are calculated; changing the definition of ''affiliate'' because of a recent judicial decision; clarifying that it will issue binding value determinations; and adding specific regulatory language regarding the issue of ''second-guessing'' a sale under an arm's-length contract. These amendments are intended to assure that royalties on Federal oil production are based on a fair value and to otherwise simplify and improve the rule.

EFFECTIVE DATE: This rule is effective June 1, 2000.

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SUPPLEMENTARY INFORMATION: The principal authors of this final rule are David A. Hubbard and Deborah Gibbs Tschudy of the Royalty Management Program (RMP) and Peter Schaumberg and Geoffrey Heath of the Office of the Solicitor in Washington, DC.

I. Background

This final rule establishes new royalty valuation procedures for crude oil produced from Federal onshore and offshore leases. This rule does not apply to oil produced from Indian leases. It replaces valuation rules in 30 CFR part 206 that have been in effect since March 1, 1988 (the 1988 rules).

The 1988 rules were developed based on the concept that gross proceeds received under an arm's-length contract represented the best measure of the value of production for royalty purposes. Further, those rules implicitly assumed the existence of a competitive and transparent market at the lease (or in the field or area) that could be used to determine the value of production not sold at arm's length.

Based on our research, we believe the main general characteristics of competitive markets include: (1) A large number of sellers, no one of whom commands a large share of the total market; (2) functional identity of different sellers' products; (3) a large enough number of buyers that sellers and buyers do not establish personal relationships with one another and no one buyer commands a large share of the total market; and (4) buyers who are well informed about the prices of different sellers. In fact, the Federal crude oil market today is dominated by large integrated producers/refiners who do command a large share of the total market. Further, because of the proprietary nature of individual contract sales of crude oil, clearly there is no sharing of price data at the lease, and none of the other conditions for a competitive domestic oil market may exist. The comments submitted throughout this 4-plus-year rulemaking effort did not demonstrate that as a general rule a competitive market exists at the lease.

The overall lack of a truly competitive market at the lease has been compounded by the significant changes that occurred in the domestic industry during the 1980's and early 1990's, which had a profound effect on how crude oil is marketed today. These changes included: (1) The major oil companies' creation of separate affiliates for production, marketing and refining; (2) overall decline in domestic production and increased dependence on foreign imports and influence of international trading practices on domestic supply; (3) sharply increased volatility of oil prices marked by the price collapse in early 1986 (the last year in which posted prices exceeded spot market prices), and the rapid rise and decline in prices in late 1990 and early 1991 in response to the Gulf War; (4) entry and expansion of resellers, traders, and brokers who bought, transported, and sold domestic crude oil, taking advantage of pricing and location discrepancies in much the same way such entities operated on the international market; and (5) development of a futures market for crude oil which alleviated many of the risks of spot trading. While many of these factors may be seen as increasing the level of competition, none of them served to increase the level of price transparency (*i.e.*, the ability to discern the prices actually paid) at the lease or field or to simplify application of the existing oil valuation rules.

The 1988 rules placed heavy emphasis on posted prices as a measure of royalty value, particularly when valuing oil disposed of non-arm's-length and under no-sales conditions. Posted prices historically were the primary mechanism for pricing domestic crude oil before the 1980's. However, with the disruption of global petroleum supplies in the 1970's and decontrol of domestic crude oil prices in 1981, the domestic petroleum industry began moving away from posted prices and towards the spot and futures markets to buy and sell crude oil. In fact, studies commissioned by States and advice from MMS consultants (Innovation & Information Consultants, Inc.; Micronomics, Inc.; Reed Consulting Group; and Summit Resource Management, Inc.) found that: (1) Sales prices often are above posted prices and are linked, in some form, to market prices, such as spot or futures prices, or represent premiums over posted prices; (2) major producers have few truly outright sales; (3) most major producers use buy/sell exchanges; (4) there are regional differences in the domestic crude oil market, particularly on the West Coast and in the Rocky Mountain Region (RMR), owing to differences in market concentration and availability of transportation options; and (5) posted prices have become a progressively less reliable indicator of the market value of crude oil since the late 1980s.

Development of the futures market and comprehensive publication of spot prices increased the market transparency of crude oil clearing prices. As a result, market participants became less willing to accept long-term sales contracts at fixed prices and instead negotiated short-term contracts with sales prices linked to spot or futures prices or to premia over posted prices. Major oil companies, however, generally continued to pay royalties on their production transferred non-arm's-length based on posted prices.

Recognizing that posted prices no longer reflected market value, State and private royalty owners in Alaska, California, Louisiana, New Mexico, and Texas brought lawsuits against several major oil companies over improper oil valuation and underpaid royalties. These lawsuits resulted in several oil companies paying additional royalties and some adjusting their posted prices to better reflect market value.

The majority of Federal lease oil production is not sold at arm's length at or near the lease. Most oil production from Federal leases is either moved directly to a refinery without a sale or disposed of under an exchange agreement (*e.g.*, buy/sell agreements) in which the lessee exchanges oil at one location for oil at another location. Exchange agreements frequently do not reference a price, but rather only the relative difference in the value of crude oils exchanged and thereby obscure the oil's actual market value. When the agreement does state a price but is conditioned upon the lessee's purchase of crude oil at a subsequent exchange point, the price specified in the exchange agreement does not necessarily represent the value of the oil. In a buy-sell exchange, the parties may state any base price they wish, because their primary concern is the difference in value between the oil sold and the oil purchased.

This rulemaking amends the current regulations by eliminating posted prices as a measure of value and relying instead on arm's-length sales prices and spot market prices as market value indicators. Today, spot prices are readily available to industry participants via price reporting services, and these and similar indicators play a significant role in crude oil marketing in terms of negotiating deals and prices.

Comments received during the rulemaking process made it apparent that regional differences exist in the domestic crude oil market. These differences are due in large part to geographic isolation of markets. Accordingly, the new rules establish different valuation procedures for three different regions: California and Alaska, the RMR, and the rest of the country.

MMS is adopting large portions of the February 1998 proposal, with certain modifications arising from:

(1) The outline published in the March 12, 1999 notice of reopening of public comment period and notice of workshops;

(2) The supplementary proposed rule published on December 30, 1999; and

(3) Our responses to public comment.

II. History of This Rulemaking

MMS published an advance notice of its intent to amend the 1988 rules on December 20, 1995 (60 FR 65610). The purpose of that notice was to solicit comments on new methodologies to establish the royalty value of Federal (and Indian) crude oil production in view of the changes in the domestic petroleum market and particularly the market's move away from posted prices as an indicator of market value. The comment period on this advance notice closed on March 19, 1996.

Based on comments received on the advance notice, together with information gained from a number of presentations by experts in the oil marketing business, MMS published its initial notice of proposed rulemaking on January 24, 1997 (62 FR 3742). That proposal, applicable both to Federal and Indian leases, set out specific valuation procedures that focused on New York Mercantile Exchange (NYMEX) prices and Alaska North Slope (ANS) spot prices as value indicators, depending on the location of the production. It also clarified the lessee's duty to market the production at no cost to the Federal Government and required the lessee to use actual transportation costs instead of FERC tariffs for transportation allowances. The comment period for that proposal was to expire March 25, 1997, but was twice extended—first to April 28, 1997 (62 FR 7189), and then to May 28, 1997 (62 FR 19966). MMS held public meetings in Lakewood, Colorado, on April 15, 1997, and Houston, Texas, on April 17, 1997, to hear comments on the proposal.

In response to the variety of comments received on the initial proposal, MMS published a supplementary proposed rule on July 3, 1997 (62 FR 36030). That proposal expanded the eligibility requirements for valuing oil disposed of under arm's-length transactions. The comment period on that proposal closed August 4, 1997.

Because of the substantial comments received on both proposals, MMS reopened the rulemaking to public comment on September 22, 1997 (62 FR 49460). MMS specifically requested comments on five valuation alternatives arising from the public comments. The initial comment period for that request was to close October 22, 1997, but was extended to November 5, 1997 (62 FR 55198). During the comment period MMS held seven public workshops to discuss valuation alternatives: in Lakewood, Colorado on September 30 and October 1, 1997 (62 FR 50544); Houston, Texas, on October 7 and 8, 1997, and again on October 14, 1997 (62 FR 50544); Bakersfield, California, on October 16, 1997 (62 FR 52518); Casper, Wyoming, on October 16, 1997 (62 FR 52518); Roswell, New Mexico, on October 21, 1997 (62 FR 55198); and Washington, DC on October 27, 1997 (62 FR 52518).

As a result of comments received on the proposed alternatives and comments made at the public workshops, MMS published a second supplementary proposed rule on February 6, 1998 (63 FR 6113), applicable to Federal leases only. The comment period for this second supplementary proposed rule was to close on March 23, 1998, but was extended to April 7, 1998 (63 FR 14057). MMS held five public workshops (63 FR 6887) on the second supplementary proposed rule, as follows: Houston, Texas, on February 18, 1998; Washington, DC on February 25, 1998; Lakewood,Colorado on March 2, 1998; Bakersfield, California, on March 11, 1998; and Casper, Wyoming, on March 12, 1998. In April 1998, before MMS could fully consider comments on the revised proposal and publish a final rule, Congress added a rider to a Fiscal Year 1998 emergency supplemental spending measure that barred MMS from implementing the rule until October 1, 1998.

Based on a request by Senator Breaux (Louisiana) to hold a meeting between industry and the Department of the Interior (DOI) to explain the direction DOI was going in the final rule, MMS once again opened the public comment period, from July 9 through July 24, 1998 (63 FR 36868). MMS participated in an initial meeting with various Senators and oil industry representatives on July 9, 1998.

On July 16, 1998, as a result of comments during the prior comment period and feedback from the July 9 meeting, MMS published a further supplementary proposed rule (63 FR 38355) that clarified some of the changes MMS intended to make when the proposed rule became final.

On July 21, 1998, Representatives Miller (California) and Maloney (New York) sponsored a meeting between DOI, States, the Indian community, and multiple special interest groups. In that meeting DOI received a variety of comments in support of its efforts to move forward with the rule and against some of the changes promoted by industry.

On July 22, 1998, MMS participated in a second meeting with U.S. Senators and oil industry representatives. That meeting involved further discussion of industry's issues and recommendations regarding the proposed rule. MMS immediately developed written responses to each industry issue and recommendation based on its published statements in prior proposed rules. MMS also extended the comment period for the proposed rule from July 24 until July 31, 1998 (63 FR 40073), to permit comment on the industry recommendations and MMS's responses.

On July 28, 1998, MMS and Departmental officials met with Senate staff members to further explain the content and rationale of the proposed rule. The notes from all of these meetings were posted on MMS's Internet Homepage for interested parties to review during the comment period.

On August 31, 1998, the Assistant Secretary for Land and Minerals Management wrote a letter to members of the Senate outlining the direction the final rule might take on several of the major issues. On October 8, 1998, the President signed the FY 1999 Department of the Interior Appropriations Act that contained language extending the moratorium prohibiting MMS from publishing a final rule until June 1, 1999. On March 4, 1999, the Secretary announced a reopening of the comment period in response to requests by members of Congress and parties interested in moving the process forward to publish a final rule. The MMS published a **Federal Register** Notice on March 12, 1999 (64 FR 12267), reopening the comment period through April 12, 1999 (64 FR 17990), and announced that it would hold public workshops in Houston, Texas; Albuquerque, New Mexico; and Washington, DC to discuss specific areas of the rule. The MMS extended the comment period through April 27, 1999, to provide commenters adequate time to provide comments following the workshops.

In a supplemental appropriations bill in May 1999, Congress extended the moratorium on publishing a final rule until October 1, 1999. In the FY 2000 Department of the Interior Appropriations Act, Congress further extended the moratorium until March 15, 2000. On December 30, 1999, MMS published a further supplemental proposed rulemaking (64 FR 73820) that proposed changes and otherwise addressed comments received during the comment period that ended April 27, 1999. The comment period for the further supplemental proposed rule closed January 31, 2000. During this comment period, MMS held three public workshops on the new proposal: in Denver, Colorado on January 18, 2000; Houston, Texas on January 19, 2000; and Washington, DC on January 20, 2000. Comments received during this latest comment period are addressed in this preamble.

The February 6, 1998, proposal, as modified by the July 16, 1998, further supplementary proposed rule, the December 30, 1999 further supplementary proposed rule, and through consideration of all comments received during the rulemaking process, led to the rule adopted here.

In the following discussion, we use the conventions shown in the following table:

When we say—	We mean—
The January 1997 proposal.	The January 24, 1997, proposed rule.
The July 1997 proposal.	The July 3, 1997, supplementary proposed rule.
The September 1997 notice.	The September 22, 1997, notice reopening the public comment period.
The February 1998 proposal.	The February 6, 1998, supplementary proposed rule.
The July 1998 proposal.	The July 16, 1998, supplementary proposed rule.
The March 1999 notice.	The March 12, 1999, notice of reopening of public comment and notice of workshops.
The December 1999 proposal.	The December 30, 1999, supplementary proposed rule.

III. Responses to Public Comments on January 1997 Proposal

Summary of Proposed Rule

The January 1997 proposal retained the concept of using gross proceeds as a valid measure of royalty value, but limited the application of gross proceeds valuation to those producers who sell their production at arm's length and otherwise do not purchase crude oil. Where oil is not disposed of at arm's length, new methods would apply. For sales to non-refiner affiliates, the valuation method would be the affiliate's arm's-length resale. Alternatively, the lessee could base value on NYMEX prices or, in California, ANS spot prices. For affiliated refiners for oil not produced in California, value would be based on a monthly average of daily NYMEX settle prices adjusted for location and quality differences. For affiliated refiners in California, value would be the ANS spot price less appropriate location/quality differentials. Differentials would be derived from published data and information collected by MMS. All oil subject to exchange agreements or crude oil calls would be valued under the non-arm's-length and no-sales procedures.

The January 1997 proposal also:

- Reiterated the lessee's duty to market the produced oil at no cost to the Federal Government consistent with implied lease covenants.
- Eliminated the specific language permitting lessees to apply for use of FERC- or State-approved tariffs for transportation allowances in lieu of their actual costs.
- Required the submittal of a new Form MMS–4415, Oil Location Differential Report, to support location and quality differentials when valuing oil under the index price (NYMEX and ANS) methods.

MMS received more than 2,000 pages of comments on this initial proposed rule. The comments fell into 18 topical categories (a through r below). Each topic begins with a description of the issue and is followed by a summary of comments and MMS's response.

(a) MMS's Rationale for Proposed Rule

Summary of Comments: Twenty-seven respondents, mostly from industry, commented on MMS's premises for the proposed rules. All except one challenged the proposed rule's rationale and concepts to one degree or another. Comments were lengthy, with several commenters making similar observations. The comments had the following themes:

- MMS does not show a need to depart from existing rules or disclose any material foundation for the proposed rule. Nor does MMS show that lease markets no longer exist or that wellhead sales don't represent market value. Reciprocal or other oil-purchase transactions do not indicate that lessees are manipulating contract prices; MMS offers no proof of lessee misconduct or price collusion. MMS's consultants were allied on one side of a vigorous debate over lease market pricing.
- Index prices are not comparable to transactions in the lease market and do not reflect the same supply and demand factors. There is an active and viable lease market with many arm's-length sales to establish value.
- The limitation on arm's-length valuation is too severe and unfounded. Almost all producers buy oil for reasons unconnected with pricing schemes (*e.g.,* for lease use or blending purposes).
- It is still feasible to value non-arm's-length sales by comparison to arm's-length sales. The existing valuation rules remain workable; they provide adequate safeguards for cases where gross proceeds don't reflect total consideration.

MMS Response: MMS's reasons for issuing new rules are given in the Background section of this preamble. The need for new rules arises not only from changes in the petroleum industry's marketing practices, but also from the facts that: (1) The old rules were developed on the premise that posted prices fairly represented market value and that there were competitive local markets; (2) exchange agreements and other oil disposal transactions have become more and more problematic to use as the basis of royalty value; and (3) transactions based on spot prices, premiums above posted prices, and other index prices dominate the manner in which crude oil is sold today. For all of these reasons, the old rules were becoming less effective in determining fair value for royalty purposes. The new rules attempt to bring the valuation procedure in step with actual market practices.

MMS does not assert that no local markets exist. Rather, due to the frequent lack of competitive local markets, there often are insufficient local arm's-length transactions to reliably determine the value of production not disposed of at arm's length. Also, the actual proceeds to the lessee often are difficult to determine due to the prevalence of exchange agreements or reciprocal purchases. In many cases, the apparent arm's-length transactions in a field or area are so limited as to be of no use in establishing royalty value. There is no need for MMS to offer proof of lessee misconduct or price collusion, because the rule's intent is simply to obtain fair, reasonable royalty values that have been difficult to obtain under the existing regulations.

(b) Use of Posted Prices

Summary of Comments:

Eighteen respondents commented on MMS's abandonment of oil postings as a measure of value. Proponents of posted prices, mainly industry commenters, maintained that oil postings were still indicative of market value because: (1) The majority of pricing provisions in oil sales contracts remain postings-related; (2) a relationship exists between NYMEX and posted prices; and (3) oil postings are used as a starting point in negotiating prices and premiums. Few commenters argued that MMS hadn't supported its claim that posted prices no longer reflect value of production at the lease. Some commenters, while still advocating posted prices, suggested that MMS resolve the problem by eliminating reference to postings in the benchmarks in its current regulations.

Opponents of posted prices, primarily State and local governmental agencies, maintained that oil postings are not a valid measure of value. To support their position, they pointed to the common payment of bonuses, or premiums, over posted prices (sometimes called the ''postings-plus'' market), to litigation settlements paid to make up for low postings, to actual sales of oil above posted prices, and to spot prices higher than postings.

MMS Response: By all accounts, the domestic petroleum industry generally no longer relies on posted prices to set arm's-length contract prices unless premiums are attached. Commissioned studies indicate that posted prices are artificially low and are used by oil companies largely for accounting purposes in effecting crude oil exchanges between themselves.

Continuing changes in oil market pricing further demonstrate the need for moving away from posted prices as a value determinant. For example, industry recently began to use a new pricing tool called Calendar MERC. It is calculated much like the ''P-plus'' price quoted in trade periodicals, and factors in assessments for both the prompt (nearest) month and the second-forward month. It is quoted as a differential off the New York Mercantile Exchange price. Although it is not clear how widely the Calendar MERC price is used at present, its development is further evidence of industry's move not only away from the direct use of posted prices in their trades, but also away from developing prices that build on posted prices in some fashion.

Further, MMS auditors have found that sales prices often are pegged to spot or futures prices. To maintain valuation procedures based on posted prices would understate the true market value of oil and diminish royalties. Consistent with the stated purposes of the proposed rule, the final rule eliminates posted prices as a measure of value.

(c) Definitions (Proposed § 206.101)

Marketing Affiliate—Summary of Comments: Two commenters recommended MMS retain the definition of ''marketing affiliate'' until the numerous administrative and legal actions concerning the affiliate issue are resolved.

MMS Response: MMS removed this definition because it is not used in the final rule. Under the 1988 rules, a ''marketing affiliate'' was defined as an affiliate of the lessee whose function was to acquire only the lessee's production and market that production. The royalty value of oil transferred non-arm's-length to the marketing affiliate then became the affiliate's gross proceeds, provided the marketing affiliate sold the oil at arm's length. Very few, if any, marketers met the strict definition of a marketing affiliate, thus making this provision of the 1988 rules almost inconsequential. The final rule adopted here does not distinguish between ''marketing affiliates,'' as defined in 1988, and other affiliates, because the value of oil transferred to any affiliate is determined by the affiliate's ultimate disposition of that oil (or, at the lessee's option, at an index price or benchmark value as discussed later). Therefore, the term ''marketing affiliate'' is no longer needed.

Gross Proceeds—Summary of Comments: Two commenters recommended changing the word ''must,'' in reference to services that must be performed at no cost to the lessor, to a more neutral term, because ''must'' implies that there never will be a situation where the costs of these services would be deductible. One commenter recommended that the definition include gross proceeds accruing to an entity affiliated with the lessee.

MMS Response: MMS maintains that the lessee must place production in marketable condition and market the production at no cost to the Federal Government. Legal decisions have long held that such costs are not deductible from royalty value. With respect to marketing costs, see, e.g., Walter Oil and Gas Corp., 111 IBLA 260 (1989); ARCO Oil and Gas Co., 112 IBLA 8 (1989); Taylor Energy Co., 143 IBLA 80 (1998) (motion for reconsideration pending); Yates Petroleum Corp., 148 IBLA 33 (1999); Amerac Energy Corp., 148 IBLA 82 (1999) (motion for reconsideration pending); Texaco Exploration and Production Inc., No. MMS–92–0306–O&G (1999) (concurrence by the Secretary)(action for judicial review pending, *Texaco Exploration and Production, Inc.* v. *Babbitt,* No. 1:99CV01670 (D.D.C.)). (The lessee's duty to market is discussed further below.) With respect to the costs of putting production into marketable condition, see, e.g., *Mesa Operating Limited Partnership* v. *Department of the Interior,* 931 F.2d 318 (5th Cir. 1991), cert. denied, 502 U.S. 1058 (1992); Texaco, Inc. v. Quarterman, Civil No. 96-CV–08–J (D. Wyo. 1997). It follows that any payments the lessee receives for performing such services are part of the value of the production and are royalty bearing.

The final rule extends gross proceeds valuation to any oil disposed of under an arm's-length contract, regardless of whether the seller is the lessee or its affiliate. Accordingly, there is no need to include gross proceeds accruing to an entity affiliated with the lessee in the definition.

Index Pricing—Summary of Comments: Two commenters recommended using more generic language in case the NYMEX or ANS index prices become unusable. One commenter suggested the definition specifically refer to the monthly average spot prices for ANS crude oil delivered in California.

MMS Response: The final rule modifies the index price definition to include spot prices for ANS, West Texas Intermediate (WTI) at Cushing, Oklahoma, and other appropriate spot prices. We also included a provision that if MMS determines that any of the index prices is unavailable or no longer represents reasonable royalty value, MMS may establish value based on other relevant matters. The final rule does not use NYMEX futures prices. For applying ANS prices in California and Alaska, the valuation rules specify the daily mean spot prices published during the production month, as explained more fully below. This method does use monthly spot prices for ANS crude.

Exchange Agreement—Summary of Comments: Three commenters believed the definition of exchange agreement was too narrow. They recommended the definition be broadened to include exchanges in which the receipt and delivery take place at the same location, multi-party exchanges, transportation exchanges, net-out and other overall balancing agreements, and exchanges involving crude for products. On the other hand, one commenter believed the definition was overly broad and should be restricted to exchanges occurring at the lease.

MMS Response: MMS modified the exchange agreement definition from that originally proposed by deleting the statement that exchange agreements do not include agreements whose principal purpose is transportation (63 FR 6116, February 6, 1998). For further clarification, the definition in the final rule also includes examples of several specific types of exchange agreements. However, in the final rule we removed the examples included in the December 1999 proposal of exchanges of produced oil for futures contracts (Exchanges for Physical, or EFP) and exchanges of produced oil for similar oil produced in different months (Time Trades). These trades or exchanges involve different time periods and may not reflect reliable location/quality differentials applicable to royalty payment for a particular production month. We believe the definition in the final rule is sufficient to implement the valuation rules.

Field—Summary of Comments: One commenter pointed out that ''field'' has no relevance under the proposed rule and should be deleted.

MMS Response: ''Field'' remains a term used in the second benchmark for valuing production not disposed of under an arm's-length contract in the RMR.

(d) Gross Proceeds Valuation (Proposed Paragraph 206.102(a))

The January 1997 proposal retained the concept of using a lessee's gross proceeds to value oil sold under an arm's-length contract. However, there were five exceptions to this provision: (1) A sales contract that does not reflect the total consideration for the value of the oil; (2) a breach of the duty to market for the mutual benefit of the lessee and the lessor; (3) oil disposed of under an exchange agreement; (4) oil subject to a call; and (5) when a lessee or its affiliate purchased crude oil from a third party in the United States within a 2-year period preceding the production month. If any of these exceptions applied, value would be determined under the index pricing methods.

Summary of Comments: Forty persons commented on arm's-length gross proceeds valuation. Most commenters (primarily industry but including the States of Louisiana and Wyoming) believed the exceptions were too restrictive. Industry argued that there are active, competitive crude oil markets at the wellhead. Accordingly, arm's-length sales at the lease properly determine value. Any application of the exceptions (*i.e.*, valuation under the index price methods) would derive a different, likely higher, value. Many objected to the requirement to use the index pricing methods when oil is purchased within the 2-year period, indicating that most producers routinely buy oil for lease operations.

Two commenters indicated that gross proceeds should not be a valuation factor for any production in California, because gross proceeds have never reflected the true value of oil in that State. They also recommended that if the arm's-length gross proceeds provision remains, it be limited to non-integrated, independent producers. Another commenter believed that the gross proceeds provision should be limited to: (1) Sales by independent producers to third parties without repurchase agreements, and (2) sales by independent producers to major oil companies without repurchase or buy/sell agreements.

MMS Response: In response to the general theme of these comments, MMS modified the eligibility requirements for oil valuation under arm's-length transactions in the July 1997 proposal. Changes included: (1) The expansion of gross proceeds valuation to situations involving competitive crude oil calls; (2) the addition of the option to use gross proceeds or index pricing if the lessee exchanges its oil at arm's length and sells the oil received in exchange at arm's length; and (3) elimination of the ''two-year rule'' (*i.e.*, the requirement to value oil using index prices for lessees who purchase oil within a 2-year period).

To address the concern about reciprocal purchasing that MMS previously handled in the ''two-year purchase provision,'' the July 1997 proposal added a provision that if the buyer and seller maintained an overall balance, the corresponding production would be valued under index pricing. MMS removed the language regarding overall balances as a separate, specific provision in the February 1998 proposal and in the final rule. However, oil subject to overall balance situations will be subject to audit and examined in view of paragraphs 206.102(c)(1) and (c)(2) to determine whether the prices received represent market value. The value of oil involved in overall balancing agreements thus ultimately will be the lessee's total consideration or the value determined by the non-arm's-length methods in § 206.103.

In the final rule, there are two exceptions to gross proceeds valuation, both of which are contained in the existing rule: a sales contract that does not reflect the total consideration for the value of production and a breach of the lessee's duty to market for the mutual benefit of the lessee and the lessor. (The final rule also provides the lessee the option of using the index value after one or more arm's-length exchanges, or one or more inter-affiliate transfers, even when the oil is then sold at arm's length, as discussed further below.) MMS maintains that gross proceeds under truly arm's-length sales are a reliable measure of market value. MMS does not believe that California production warrants a different valuation philosophy for arm's-length transactions.

(e) Valuing Oil Disposed of Under Exchange Agreements (Proposed Paragraph 206.102(a)(4))

In the January 1997 proposal, MMS excluded exchange agreements from arm's-length transactions because such agreements may or may not specify prices for the oil involved. Instead, they frequently specify dollar amounts only for location, quality, or other differentials. Where exchange agreements do specify prices, those prices may be meaningless because the contracting parties' concern is the relative parity in the value of oil production traded. MMS included buy/sell agreements in its definition of exchange agreements.

Summary of Comments: Thirteen respondents commented on the exchange agreement issue. Industry commenters generally objected to the inclusion of buy/sell agreements with exchange agreements, arguing instead that buy/sell agreements should be treated as arm's-length sales contracts or transportation contracts. They argued that there is often no real distinction between a buy/sell agreement, which is treated as an exchange agreement, and a transportation agreement, which is not treated as an exchange agreement. They argued that this is particularly so in California where companies owning proprietary pipelines require independent producers to enter into a transportation agreement that looks exactly like a buy/sell agreement.

With regard to exchanges in general, State and local government agencies supported MMS's proposed exclusion of exchange agreements from arm's-length valuation, but recommended broadening the definition of exchange agreement (discussed above). Several industry commenters recommended valuing oil transferred under exchange agreements by reference to comparable sales.

MMS Response: Buy/sell agreements are vulnerable to the same flaws as other exchange agreements in which the exchange terms involve only relative differentials rather than stated unit prices. Work done by the MMS-sponsored Interagency Task Force investigating California oil undervaluation, advice from several consultants, and ongoing work by MMS auditors, led MMS to its conclusion that exchange agreements, including buy/sells, may not be reliable as value indicators. However, in the July 1997 proposal, MMS modified the valuation procedures for oil involved in exchanges. This modification permitted a choice of using either the gross proceeds from the sale of the acquired oil (provided the acquired oil is sold at arm's length) or an index price to value the exchanged oil. This option applied only to single exchanges before the arm's-length sale of the acquired oil. As discussed below in Section VI at (b), in the February 1998 proposal, MMS extended the concept of applying the gross proceeds after a single exchange to multiple exchanges, but without the option to use an index price. The final rule offers the option of using the arm's-length gross proceeds after one or multiple arm's-length exchanges, or applying the index price or benchmarks appropriate to the region where the production occurs.

MMS is not relying on a comparable sales approach, except in limited circumstances in the RMR as discussed below, primarily because of the lack of transparent markets at the lease.

(f) Crude Oil Calls (Proposed Paragraphs 206.102(a)(4) and (c)(2))

Under the January 1997 proposal, MMS did not recognize oil disposed of under a crude oil call as sold at arm's length, regardless of whether the buyer and seller are affiliated; such oil would be valued under proposed 30 CFR 206.102(c), using the index price method.

Summary of Comments: Twelve respondents commented on crude oil calls. Most commenters believed that the proposed rule was too restrictive, claiming that crude oil call agreements usually include the best price and therefore should be considered arm's-length. Commenters indicated that when calls are not exercised, the oil is sold at arm's length anyway. Two State respondents suggested that oil subject to crude oil calls should be valued as non arm's length only when the call is actually exercised.

MMS Response: MMS recognized in the July 1997 proposal that not all crude oil calls are exercised and that some calls are subject to competitive bid. In the February 1998 proposal, MMS modified the rules regarding competitive crude oil calls to accept arm's-length gross proceeds as value in these situations. In the final rule, MMS removed the language regarding noncompetitive crude oil calls as a separate, specific provision. However, oil subject to a noncompetitive crude oil call will be examined in view of paragraphs 206.102(c)(1) and (c)(2) to determine whether the prices received represent market value. The value of oil involved in a noncompetitive crude oil call thus ultimately will be the lessee's total consideration or the value determined by the non-arm's-length methods in § 206.103.

(g) NYMEX Pricing (Proposed Paragraph 206.102(c)(2)(i))

For oil produced outside California and Alaska and not sold by the lessee or its affiliate under an arm's-length contract, MMS proposed in January 1997 that value be determined as the average of the daily NYMEX futures settle prices for WTI crude oil at Cushing, Oklahoma, for the prompt month (the month following the month of production). MMS proposed NYMEX prices because they were perceived to best reflect the current domestic crude oil market value on any given day, and there is minimal likelihood that any one party could influence them. To establish royalty value, the NYMEX prices would be reduced by location and quality differentials. (See also Form MMS–4415 at m below.)

Summary of Comments: A total of 54 respondents commented on the NYMEX pricing proposal. Industry commenters unanimously opposed the idea, whereas States and other governmental agencies were divided, with some supporting the proposal and others opposing it. Opposing comments generally revolved around the asserted difference between the NYMEX market and the lease market. Comments included:

- NYMEX is a futures market that bears little relation to the market at the lease. Lease prices are driven by local supply and demand factors, not by NYMEX pricing; the NYMEX market is not synchronized with lease-market factors. NYMEX is not influenced by factors present at the lease, such as operational and transportation costs; the ease of oil futures trading gives the oil more value than it has at the lease.
- NYMEX prices are speculative and artificial. Those purchasing oil futures in the NYMEX market buy a right to obtain certain types of oil in the future at specified prices; NYMEX does not represent current sales. NYMEX is used to hedge against financial risks; only 30 percent of participants are industry, and 70 percent are speculators. Trade volumes are 10 to 20 times actual U.S. production, but only 3.1 percent of trades are carried out. NYMEX is mainly a paper market. Profits are made in successfully guessing the optimal timing of trades. Prices can be distorted by changing perceptions of risk, activities of speculators, and world events, such as wars and natural catastrophes. The settlement price is computed from transactions that occur only in the last few minutes of each day's trading.
- NYMEX-based valuation is contrary to the royalty provisions of the leasing statutes and lease terms, which require valuation at the lease at the time of production; NYMEX pricing does not provide contemporaneous valuation because the prompt month does not coincide with the production month.
- NYMEX does not represent the crude oil market in the RMR, which is driven by refinery-product prices, not the NYMEX.

One commenter suggested using adjusted spot prices instead of the NYMEX method to value production, particularly for the Gulf of Mexico.

Proponents of NYMEX pricing believed it is a valid measure of the market value of crude oil. Reasons included (1) the large volume of oil traded; (2) invulnerability to manipulation or control (however, a few of the opponents of NYMEX pricing indicated that the NYMEX market is indeed vulnerable to manipulation); and (3) the opportunity for arbitrage to mediate the differences between the values of paper barrels and actual barrels of oil.

MMS Response: The final rule does not use NYMEX as a measure of value. However, the body of evidence regarding actual marketing practices indicates that index prices play a significant role in setting contract prices. In considering the numerous comments, MMS dropped its NYMEX pricing approach in the February 1998 proposal except for the third benchmark in valuation of crude oil produced in the newly-defined RMR and not disposed of at arm's length. In the final rule, MMS also dropped NYMEX as a valuation basis in the RMR.

For leases outside California, Alaska, and the RMR, in February 1998 MMS proposed to use spot, rather than NYMEX, prices to value oil not disposed of at arm's length. We made this change because spot prices nearly duplicate NYMEX prices when NYMEX prices are properly adjusted for location and quality differentials. Moving to spot prices at the market center thus saves one step in the adjustment of NYMEX prices back to the lease, namely the adjustment between Cushing, Oklahoma, and the market center. Spot prices are valid indicators of market value because they and similar prices play a significant role in sales contracts and they are readily available to lessees via commercial price reporting services.

For the RMR, the final rule uses the WTI spot price at Cushing, Oklahoma, adjusted for location and quality, as the third valuation benchmark for oil not disposed of at arm's length. We believe that this valuation mechanism is appropriate for the RMR because the only published spot price for this region at this point in time—at Guernsey, Wyoming—is derived from a survey of the few trades occurring at that location. The price, therefore, is not a reliable measure of value.

(h) ANS Spot Prices (Proposed Paragraph 206.102(c)(2)(ii))

For oil produced in California and Alaska and not sold by the lessee or its affiliate under an arm's-length contract, MMS proposed, in January 1997, that value be the average of the daily mean ANS spot prices for the month of production published in an MMS-approved publication. MMS chose ANS spot prices because they represent large volumes of oil delivered into the California market and used as refinery feedstock. In contrast, the other spot prices published for local California crude oil (including, for example, Kern River and Line 63), like those published for Guernsey, Wyoming, do not involve large enough volumes to justify their use for royalty valuation. To establish royalty value, the ANS spot prices would be adjusted for location and quality differentials.

Summary of Comments: Fifteen industry commenters opposed the ANS pricing proposal, while two California governmental agencies supported it. Opposing arguments included:

- The reported ANS spot prices are unreliable because transaction volumes are small; only 10 percent of ANS production is sold on the spot market, all of it by only one company.
- The ANS price quotes are indicative of the value of ANS crude delivered in waterborne cargo volumes and not of the value of California crude oils delivered by pipeline.
- The method used by the trade press to determine spot prices is unclear, and many of the transactions reported to the trade press involve buy/sell exchanges which MMS believes to be unreliable.
- The quality of ANS crude is very different from California crude. ANS crude is relatively light compared to crude oil produced in California. Much of California crude is heavy and contains heavy metals and other impurities that cause refining difficulties. Accordingly, California crude prices are discounted relative to ANS crude.

In summary, industry believed that the ANS method would not reflect the value of California crude oil. A few commenters asserted that the calculated values would be much higher than those realized in actual sales or through local spot prices.

California governmental agencies (the State and one municipality) endorsed the ANS method. They stated that ANS crude directly competes with California crude as refinery feedstock—often accounting for more than one-third of the oil refined in California—and thus should form the basis for a competitive price for California crude. In support of this, one commenter indicated that the major California oil companies evaluated the actual value of California crudes by comparing them to the ANS spot prices; this commenter concluded that the major oil companies viewed the ANS price as the market value of California crudes. The other commenter was concerned that the published ANS prices might become unavailable or fail to yield a reasonable value. This commenter recommended a safety net for ANS pricing at no less than 20 percent below the NYMEX price to guard against these situations.

MMS Response: California, and the West Coast in general, has long been recognized as a separate crude oil market isolated from the rest of the country. ANS crude is competitive with California crudes. While it may be true that only 10 percent of ANS crude is sold on the spot market, over 30 percent of the oil refined in California is ANS oil. An interagency study has found that companies engaged in buying and selling California crude oil commonly use ANS spot prices as the benchmark for determining California crude values (Final Interagency Report on the Valuation of Oil Produced from Federal Leases in California, May 16, 1996; Long Beach litigation). These companies apparently have no difficulty in adjusting the ANS prices for quality differences to derive the prices, including premia over postings, they are willing to pay for California crude oils. MMS believes ANS spot prices are a recognized benchmark for valuing California crudes and a reliable indicator of the market value of California crude oils.

Comments alleging that ANS spot prices are unreliable because ANS crude is thinly traded were analyzed for MMS by Innovation & Information Consultants, Inc. (Memorandum to MMS file, September 25, 1997). They report that it is the spot market for local California crude oils, not ANS crude, that is thinly traded and thus leads to unreliable price indices. They also report that there is a high degree of correlation between ANS spot prices and prices actually paid for California crudes. They indicate that the major oil companies in California regularly make comparisons between California crude oils and ANS with the understanding and expectation that a California crude should equate to ANS in value after accounting for location and quality differences.

(i) Duty to Market (Proposed Paragraph 206.102(e)(1))

The January 1997 proposal restated the lessee's duty to market the oil for the mutual benefit of the lessee and lessor at no cost to the Federal Government, consistent with longstanding Departmental practice and implied lease covenants.

Summary of Comments: Nineteen respondents, all representing industry, commented on the duty-to-market provision. They all opposed the provision on the following grounds:

- Downstream marketing costs enhance the value of the oil. MMS is not entitled to claim royalties on the value added by those expenses and risks incidental to downstream activities, particularly when value is determined at a marketing center downstream of the lease.
- The lessor does not share mutually in the risks inherent in downstream marketing activities; accordingly, there is no mutual benefit when one party bears all the costs and risks.
- There is no legal foundation supporting a no-cost duty to market when the point of royalty determination

is moved to a downstream market center.

- Placing production in marketable condition (physically conditioning the production for market) is separate from a duty to market; lease terms do not require the lessee to market the production at no cost to the lessor.

MMS Response: It is a well-established principle of oil and gas law that lessees have the obligation to market lease production for the mutual benefit of the lessee and lessor, without deduction for the costs of marketing. See, e.g., Walter Oil and Gas Corp., 111 IBLA 260 (1989); Arco Oil and Gas Co., 112 IBLA 8 (1989); Taylor Energy Co., 143 IBLA 80 (1998) (motion for reconsideration pending); Yates Petroleum Corp., 148 IBLA 33 (1999); Amerac Energy Corp., 148 IBLA 82 (1999) (motion for reconsideration pending); Texaco Exploration and Production Inc., No. MMS–92–0306–O&G (1999) (concurrence by the Secretary) (action for judicial review pending, *Texaco Exploration and Production Inc.* v. *Babbitt,* No. 1:99CV01670 (D.D.C.)).

In the context of Federal leases, the D.C. Circuit referred to this implied lease covenant many years ago in *California Co.* v. *Udall,* 296 F.2d 384, 387 (D.C. Cir. 1961), stating that ''the lessee was obliged to market the product.'' The duty to market at no cost to the lessor is not unique to Federal leases. See, e.g., Merrill, Covenants Implied in Oil and Gas Leases (2d Ed. 1940), section 84–86 (Noting ''[n]o part of the costs of marketing or of preparation for sale is chargeable to the lessor''); ''Direct Gas Sales: Royalty Problems for the Producer,'' 46 Okla. L. Rev. 235 (1993); *Amoco Production Co.* v. *First Baptist Church of* Pyote, 579 S.W.2d 280 (Tex. Civ. App. 1979), writ ref'd n.r.e., 611 S.W.2d 610 (Tex. 1981), and cases cited in these authorities.

This duty to market means that the lessee must act as a prudent marketer. The duty to market is an implied covenant of virtually all oil and gas leases, whether the leases are private, Federal, or State leases. MMS as lessor has never shared in the ''risks'' of marketing and has never allowed deductions from royalty value for marketing costs. This rulemaking makes no change to the lessee's duty to market.

The decisions cited above establish several principles. First, the lessee has an implied duty to prudently market the production at the highest price obtainable for the mutual benefit of both the lessee and the lessor. The creation and development of markets is the essence of that obligation, as the IBLA expressed it ten years ago in Arco Oil and Gas Co., supra:

> The creation and development of markets for production is the very essence of the lessee's implied obligation to prudently market production from the lease at the highest price obtainable for the mutual benefit of the lessee and lessor. Traditionally, Federal gas lessees have borne 100 percent of the costs of developing a market for gas. Appellant has cited no authority, nor do we find any, which supports an allowance for creation and development of markets for the royalty share of production.

112 IBLA at 11.

Because of industry's repeatedly-expressed concerns in the comments and workshops, MMS emphasizes that this does not imply that lessees are somehow prohibited from marketing at the lease and must market production ''downstream.'' Lessees may market at the lease without breaching the duty to market. However, if a lessee chooses to market downstream, the choice to do so is for the mutual benefit of itself and the lessor, and does not affect the lessee's relationship to the lessor. The choice to market downstream does not make marketing costs deductible or permit the lessee to disregard part of the sales price obtained at a downstream market.

In addition, lessees have always borne all of the marketing costs. The Department has not knowingly permitted an allowance or deduction from royalty value for marketing costs. As the Board held a decade ago in Walter Oil and Gas Corp., supra:

> The only allowances recognized as proper deductions in determining royalty value are transportation allowances for the cost of transporting production from the leasehold to the first available market, which has been considered a relevant factor pursuant to 30 C.F.R. 206.150(e) * * * and processing allowances for processed gas authorized by 30 C.F.R. 206.152(a)(2) (1987). * * * Walter's unsupported assumption that it is somehow entitled to deduct its marketing costs from royalty value fails in the face of contrary regulatory requirements * * *.

111 IBLA at 265.

Lessees may deduct from value only those costs allowed by the regulations, especially in light of the gross proceeds minimum value requirement. The only deductible costs are transportation costs and, in the case of ''wet'' gas with heavier entrained liquid hydrocarbons, processing costs.

Further, marketing costs are not deductible, regardless of whether the lessee bears them directly or transfers the marketing function or costs to a contractor or an affiliate.

Moreover, the fact that marketing arrangements enhance the lessee's ability to obtain a higher price does not imply that marketing costs are deductible. It also follows that a lessee may not deduct or disregard for royalty purposes the additional benefits it gains or value it receives through obtaining a higher price through its marketing skill or expertise. If the lessee manages to obtain a higher price for its oil through skillful marketing efforts, that higher price is the minimum royalty value under the gross proceeds rule.

At the same time, the location of the market at which the lessee chooses to sell its production does not change the lessee's obligation. Much of industry's opposition to the duty-to-market provision in the proposed and final rules revolves around the argument that when royalty value is based on the sale of production at a downstream location, the downstream transportation, risks, and related services add more value to the oil than is reflected in the transportation allowances (or location differentials) MMS permits.

The industry commenters' argument is contrary to established principles and uniform longstanding practice. Valuation based upon a ''downstream'' sale or disposition of production has been commonplace for many years. For sales at distant markets, the lessee is entitled to an allowance for transportation costs, but not for marketing costs. Sales away from (or ''downstream'' from) the lease often are the starting point for determining royalty value, and the costs of transportation always have been allowed in order to ascertain value at or near the lease. A lessee who transports production to sell it at a market remote from the lease or field is entitled to an allowance for the costs of transportation. See 30 C.F.R. 206.104, 206.105 (crude oil), 206.156 and 206.157 (gas) (1988–1997). Before the 1988 regulations, transportation costs were allowed under judicial and administrative cases. See, e.g., *United States* v. *General Petroleum Corp.,* 73 F. Supp 225 (S.D. Cal. 1946), aff'd, *Continental Oil Co.* v. *United States,* 184 F.2d 802 (9th Cir. 1950); *Arco Oil and Gas Co.,* 109 IBLA 34 (1989); *Shell Oil Co.,* 52 IBLA 15 (1981); *Shell Oil Co.,* 70 I.D. 393, 396 (1963).

An illustrative example is *Marathon Oil Co.* v. *United States,* 604 F. Supp.. 1375 (D. Alaska 1985), aff'd, 807 F.2d 759 (9th Cir. 1986), cert. denied, 480 U.S. 940 (1987). In that case, Marathon produced natural gas from Federal leases in Alaska, and sold it in Japan after overseas transportation in liquid form by tanker. The court held that MMS properly deducted Marathon's costs of transportation (including liquefaction) from the sales price in

Japan to derive the royalty value (gross proceeds) at the lease.

Indeed, transportation allowances have been common for decades precisely because the initial basis for establishing value often is a ''downstream'' sales price. Industry's argument that MMS is somehow improperly trying to ''tap into'' the benefits industry derives from its marketing expertise clouds the real issue. If a lessee can obtain a better price by selling away from the lease, then it will do so. How the lessee markets its production is its decision. The lessor is entitled to its royalty share of the total value derived from the production regardless of how the lessee chooses to dispose of it. The United States as lessor always has shared in the ''benefit'' of ''downstream'' marketing away from the lease, and has allowed deductions for the cost of transportation accordingly.

Moreover, these principles do not change in the event that a wholly-owned or wholly-commonly-owned affiliated marketing entity buys other production at arm's length from other working interest holders in the field at the same price it pays to its affiliated producer. The industry wants to limit royalty value to supposedly ''comparable'' sales at the lease even when the lessee receives a higher price for its production. In effect, industry wants to force MMS to adopt a ''lowest common denominator'' theory of valuation—*i.e.,* the price at which any production is sold at arm's length at the lease will be the value of production initially transferred non-arm's-length, even if the latter production nets a higher price in the open market. That position is incorrect for several reasons.

First, it would enable a lessee whose enterprise realizes more proceeds or greater value for its production than some other producers in the field to avoid paying royalty on part of those proceeds. If the lessee sells downstream, its gross proceeds are the higher price realized on the sale downstream, minus the lessee's transportation costs, regardless of the fact that other producers sold for less. The industry's position is directly contrary to *Marathon Oil Co.* v. *United States, supra.* If the lessee first transfers to a wholly-owned or wholly-commonly-owned affiliate who then resells at arm's length downstream, it is still true that the producing entity could have sold its production at the point and at the price its affiliate did, instead of using the wholly-owned affiliate arrangement. It is perfectly proper to value the production of a producer who markets through a wholly-owned affiliate at a higher level than the production that other producers sell at arm's length in the first instance, when the production marketed through the wholly-owned affiliate commands a higher price. Indeed, this is the very situation which the Third Circuit correctly anticipated in *Shell Oil Co.* v. *Babbitt,* 125 F.3d 172 (3d Cir. 1997).

Further, the industry's position would create an incentive for a lessee to sell some small percentage of its production at the lease at arm's-length for a lower price so that it can pay royalty on the rest of its production at that price. Such a result is contrary to the intent and meaning of the gross proceeds rule.

MMS agrees that the duty to market production for the mutual benefit of the lessee and the lessor at no cost to the lessor is not the same as the lessee's duty to put production into marketable condition at no cost to the lessor. However, the fact that the two duties are not identical does not support the industry commenters' position. The decision of the Secretary and the Assistant Secretary for Land and Minerals Management in Texaco Exploration and Production Inc., supra (at pp. 16–19), discusses the relationship of the two duties, and MMS adopts the reasoning of that decision in response to the commenters' argument.

(j) Differentials (Proposed Paragraph 206.105(c))

When value is based on index pricing, certain location and quality differentials are required to adjust the value of the oil at the index pricing point to obtain royalty value of the oil produced from the lease. The January 1997 proposal applied location and quality differentials to adjust the value between (1) the index pricing point and the appropriate market center and (2) the market center and the aggregation point. The first differential was the difference between the average spot prices for the respective crude oils at the index pricing point and at the market center. The second differential was either an express differential under an arm's-length exchange agreement relative to the market center/aggregation point pair or a differential calculated and published by MMS for the market center/aggregation point pair. MMS would have determined the latter differential from information reported on Form MMS–4415.

The location differentials reflect the relative differences in the value of crude oil delivered at different locations; they are not transportation cost allowances. Under the January 1997 proposal, the lessee would use transportation allowances to adjust the value of the crude oil from the aggregation point (or market center) to the lease. Comments on transportation allowances are addressed elsewhere in this preamble.

Summary of Comments: Thirty-one respondents commented on differentials. Comments generally fell into two categories:

(1) The differentials would be 1 year out of date and would not reflect market conditions at the time of production. They particularly ignore the dynamic supply and demand processes that operate on daily and seasonal bases.

(2) The differentials would not adequately adjust for quality differences between the lease and the index pricing point because of commingling. There is no gravity adjustment between the lease and the aggregation point.

In sum, many commenters believed that the differentials would not capture the value of oil produced at the lease. Other comments included:

- Differentials do not recognize all transportation costs or value added from blending, aggregation, storage, and other marketing services.
- Aggregation points with limited transactions will give statistically invalid differentials.
- Exchange agreements may not provide all the needed data or specify which lease(s) the oil came from.
- Differentials might be calculated from inaccurate and unreliable data, particularly with regard to selecting ''alternative disposal points.''
- Gathering is not adequately addressed in the calculation of differentials.
- Spot prices represent marginal barrels (small volume) to make up for refinery needs; they do not reflect the price differences between the market centers and index pricing points.
- For California, a comparison of ANS spot prices and field spot prices captures more than the price difference attributable to location. Furthermore, where spot prices are reported for a field rather than an aggregation point, and the exchange reflects a transfer at the lease or field, the differential would permit a lessee to recover the cost of transporting to an ''aggregation point'' twice.

MMS Response: In the final rule, in response to the various comments, MMS modified the previous proposals governing differentials by:

(1) Eliminating MMS-published differentials because MMS believes that lessees that would be subject to index pricing generally will have sufficient information to accurately determine location/quality differentials, with relatively rare exceptions. As a result of eliminating MMS-published differentials, the proposed Form MMS–4415 is not part of the final rule.

Because MMS is not requiring the proposed form, it is not necessary to address the extensive comments MMS received regarding the content and timing of the form.

(2) Eliminating the location differential between the index pricing point and the market center because using spot market prices has made the index pricing point and market center the same.

(3) Recognizing separate quality adjustments to reflect the differences between the oil produced from the lease and the oil at the market center or refinery or other alternate disposal point, or between intermediate exchange points. Those quality adjustments specified in exchange agreements will automatically account for those differences in quality.

Other appropriate quality adjustments would be based on pipeline quality bank specifications and related premia and penalties. MMS believes these changes will permit determination of reasonable and proper differentials.

(k) Requiring Use of Actual Transportation Costs (Amended Paragraphs 206.105 (b) and (g))

Aside from new rules at proposed paragraph 206.105(c) addressing differentials and transportation allowances under the proposed index pricing methodology, MMS's other change to the transportation allowance rules in the January 1997 proposal was the proposed deletion of existing paragraph 206.105(b)(5). That paragraph allows those lessees with non-arm's-length or no transportation agreements to apply for an exception from the requirement to compute their actual transportation costs and instead use a FERC- or State-approved tariff. Deleting this paragraph would remove the exception and require lessees to use actual transportation costs in all cases.

MMS also proposed to amend existing paragraph 206.105(f) (proposed to be redesignated as paragraph 206.105(g)), which disallows deductions for actual or theoretical losses. MMS made this change to be consistent with the deletion of paragraph 206.105(b)(5). In the final rule, the language addressing actual or theoretical losses appears at new § 206.118.

Summary of Comments: Sixteen respondents commented on the proposed change. Three commenters supported removing the exception, stating that actual costs better reflect a netted back value and that tariffs are not reviewed to determine their reasonableness.

The remaining commenters contended that FERC tariffs remain a viable measure of transportation costs in non-arm's-length movements. They argued that it is discriminatory to treat affiliated producers, who would have to use their transporting affiliate's actual costs, differently from non-affiliated producers, who may pay a FERC tariff as their arm's-length transportation cost. They particularly asserted that line losses should be an allowable cost to be comparable with costs included in FERC tariffs.

MMS Response: MMS has deleted this provision in the final rule because it continues to believe that doing so results in allowances better reflecting lessees' actual transportation costs. There is no discrimination between producers with transportation affiliates who must use their calculated actual transportation costs and non-affiliates who may apply a FERC tariff as their arm's-length transportation cost. In both instances the parties would be deducting their actual, reasonable transportation costs. Consistent with this concept, the final rule permits a deduction for oil transportation resulting from payments (either volumetric or for value) for actual or theoretical losses only under an arm's-length contract.

(l) Transportation Cost Allowances for California and Alaska (Proposed Paragraph 206.105(c)(3)(ii))

As initially proposed in January 1997, the determination of differentials and transportation allowances depends on whether the oil is (1) disposed of under an arm's-length exchange agreement with an express location differential; (2) moved directly to an alternate disposal point, such as a refinery; or (3) moved directly to a market center. For oil moved directly to an alternate disposal point, proposed paragraph 206.105(c)(3)(ii), and, similarly, proposed paragraph 206.105(c)(2)(ii), permitted deduction of a transportation allowance based on the actual costs of transporting the oil between the lease and the alternate disposal point. In addition, this section permitted deduction of a location differential, calculated as the difference between the average published spot price at the aggregation point nearest the lease and the spot prices for ANS crude at the associated market center/index pricing point.

Summary of Comments: Two commenters noted that this provision may allow for substantial ''double dipping'' of transportation cost deductions. They indicated that spot prices reflect in part the cost of moving the crude from the aggregation point to the market center. If transportation to the alternate disposal point bypasses an aggregation point, the lessee is allowed to deduct its actual transportation costs plus a location differential, which, having been computed from spot prices, has imbedded transportation costs. The transportation allowance thus will double the deduction for the location differential between the lease and the market center.

They also asserted that the proposed rule did not restrict the location of the alternate disposal point relative to the lease, meaning that crude could be shipped cross country and have a substantial transportation deduction. They recommended that MMS limit the maximum transportation cost deduction to no more than the cost of moving the crude by pipeline from the lease to the nearest market center.

MMS Response: Sections 206.105(c)(2)(ii) and (c)(3)(ii) of the January 1997 proposal were modified and reproposed as §§ 206.112 and 206.113 in the February 1998 proposal, which are now adopted as § 206.112 in the final rule with changes discussed below. In the final rule, if a lessee or its affiliate transports lease production directly to an alternate disposal point, it may adjust the index price for the actual costs of transportation under § 206.110 or § 206.111. The lessee must also adjust the index price for quality based on premia or penalties determined by pipeline quality bank specifications. This will not result in the ''double-dipping'' with which the commenter was concerned. The final rule also includes a provision at § 206.112(g) that prohibits a lessee from using any transportation or quality adjustment that duplicates all or part of any other adjustment, thus eliminating any possibility of double deduction for the location differential between the lease and the alternate disposal point or market center. MMS believes that as a practical matter, alternate disposal points will be reasonable distances from the lease and that no cost limits (beyond the 50 percent limit contained in this final rule at § 206.109(c)) are necessary.

(m) Form MMS–4415 (Proposed Paragraph 206.105(d)(3))

Under the January 1997 proposal, all lessees and their affiliates annually would have to submit proposed Form MMS–4415, Oil Location Differential Report, to enable MMS to calculate location and quality differentials under the index pricing methods. As originally proposed, information would be collected for all leases—Federal, State, private, and Indian. MMS would use the reported data to calculate and publish acceptable differentials between market centers and aggregation points.

Summary of Comments: Twenty-eight respondents commented on the proposed form. Most comments were negative and revolved around the added cost and administrative burden of preparing the reports; many comments questioned the accuracy of the calculated differentials. Comments included:

- Data collection is time consuming, burdensome, and costly.
- The reporting requirement violates the Paperwork Reduction Act.
- MMS's cost and time estimates are inadequate. They do not reflect the actual time needed to acquire the data and complete the report; nor do they reflect the costs of systems or accounting changes needed to comply with the reporting requirement.
- Annual differentials do not reflect daily or seasonal market changes (*i.e.*, current market conditions); therefore, the differentials will be inaccurate and constantly out of date.
- Multiple crude oil grades exchanged at a given aggregation point, and other factors, mask the true value in exchange agreements.
- Transporting crude oil from the lease to a market center may involve multiple transportation segments and exchanges, thus compounding the data collection and reporting burden.
- MMS does not have the authority to collect information on non-Federal leases.
- Instructions are ambiguous or incomplete; for example, who completes the form when the payor is not the lessee, what 12-month period is used, and when is a report required when different exchange agreements apply to a lease in different months?
- The method of calculating the differentials is not clear, and industry will not be able to verify results because the information is proprietary.
- The information does not reflect exchanges that occur at the wellhead.
- The information may be duplicative and misrepresentative, such as when two payors report the same exchange.
- Determining what contracts contain crude oil calls might require considerable research, since reporting parties may not know when a call provision has been exercised.

One State recommended that instead of requiring Form MMS–4415 to calculate a transportation differential, MMS should publish a rate based on the lowest FERC tariff for which a significant amount of crude oil moves from the aggregation point to the market center. This State also recommended that information collection be limited to exchanges at the lease and market center, thus eliminating the need to calculate differentials to and from the aggregation point.

MMS Response: In the final rule, MMS will not publish location/quality differentials because MMS believes that lessees generally will have sufficient information to accurately determine them, with relatively rare exceptions. If a lessee disposes of its oil through one or more exchange agreements, it ordinarily should have the information necessary to determine adjustments to the index price. As a result of eliminating MMS-published differentials, the proposed Form MMS–4415 is not part of the final rule. Because MMS is not requiring the proposed form, it is not necessary to address the extensive comments MMS received regarding the content and timing of the form.

If the oil is not disposed of through exchange agreements, then the lessee is physically transporting the oil either to a market center or to an alternate disposal point (such as a refinery.) In that event, the lessee will have the necessary information regarding actual transportation costs to claim the appropriate transportation allowance.

(n) Sale of Federal Royalty Oil (Proposed Paragraph 208.4(b)(2))

In the January 1997 proposal, MMS proposed to tie the royalty-in-kind (RIK) valuation to the index pricing provisions of 30 CFR 206.102(c)(2). MMS believed this change would provide certainty in pricing for buyers and simplify reporting for producers.

Summary of Comments: Aside from the numerous commenters that recommended MMS take all its royalty in kind and market it, five respondents provided comments relevant to the proposed regulatory change. Comments included:

- The rules should allow RIK refiners to opt in and out of contracts without terminating the contracts.
- Index pricing does not provide an incentive to RIK refiners because they can buy cheaper crude under long-term contracts. Arm's-length prices should be used for royalty value.
- RIK refiners need assurance they will not be liable for retroactive price provisions, and that the price invoiced is final and not subject to later revision; producers should be liable for any adjustments.
- RIK refiners should be billed for actual volumes delivered, not produced; MMS should penalize the producer for not delivering the RIK volume.
- RIK refiners should receive value and volume information at the same time as MMS.

One commenter recommended scrapping the RIK program because it is too difficult and costly to administer.

MMS Response: In the February 1998 proposal, MMS decided not to proceed with the proposal to modify the RIK valuation procedures. Instead, MMS decided to establish future RIK pricing terms directly within the RIK contracts. Therefore, this issue is not part of this rulemaking.

(o) Added Administrative and Economic Burdens

Summary of Comments: Twenty-five commenters thought the proposed rules would create a considerable administrative burden and add additional costs for both industry and MMS. Many comments were on the preparation of Form MMS–4415. They indicated that acquiring and compiling the needed information would take much longer than MMS's estimate of 15 minutes. (One commenter estimated 2 hours per form.) Other comments indicated there would be additional costs due to new accounting systems, new software, and additional personnel needed to administer the new rules, both for industry and MMS. A few commenters speculated that the added costs to producers, particularly small producers, might force abandonment of marginal wells or investment in other areas.

MMS Response: As discussed previously, MMS eliminated Form MMS–4415 in the final rule. We discuss other administrative costs in Section XI of this preamble.

(p) Fairness, Procedural Conduct, and Workability

Summary of Comments: Thirty-three industry respondents opposed as inequitable the valuation methods of the January 1997 proposal for oil not sold at arm's length. Their comments revolved around the index pricing method and had the following themes:

- The leasing acts and lease terms require valuation at the lease. MMS exceeds its statutory authority by implementing a valuation method away from the lease without recognizing all the downstream value-added costs and risks (such as marketing costs) as deductions. This overstates the value of production at the lease and creates "phantom income" to which MMS is not entitled. (Some commenters believed the index pricing method was tantamount to price fixing.)
- The proposed rule has dual standards. It discriminates between

similarly-situated lessees by requiring the integrated lessee to base value on a different methodology. It disqualifies many producers from using their gross proceeds as value when they engage in exchanges or oil purchases.

- The proposed rule is contrary to the deepwater royalty reduction program.
- The index-pricing method might force RIK refiners into paying higher prices.

Some commenters believed that MMS failed to articulate a factual basis for its conclusion that arm's-length transaction prices are no longer valid indicators of value. They also argued that MMS had not provided sufficient time for industry to analyze and comment on the proposed rule and claimed that MMS had not complied with the Unfunded Mandates Reform Act, the Paperwork Reduction Act, Executive Order 12630, or Executive Order 12866. Some commenters believed that the proposed rule is extremely complex and difficult to implement.

MMS Response: As indicated in the Background section of this preamble, the reason for this rulemaking is to assure that royalties are based on market values. The modifications adopted in this final rule strengthen the market value concept for royalty valuation.

The final rule maintains the concept of using a lessee's gross proceeds to value production sold at arm's-length. However, most Federal oil is disposed of under other than arm's-length conditions. Different standards historically have existed for dispositions not at arm's length, because such transactions are not reliable indicators of what parties will do in a competitive market. Contract prices between affiliated entities may be influenced by many factors other than market forces.

MMS also notes that the governing statutes and lease terms give the Secretary the authority to establish royalty value. The Mineral Leasing Act of 1920 (MLA), as amended numerous times, authorizes the Secretary to prescribe necessary and proper rules and regulations to carry out the purposes of the MLA. The Outer Continental Shelf Lands Act of 1953 (OCSLA), as amended, requires the Secretary to administer the provisions of the OCSLA relating to the leasing of the OCS, and authorizes the Secretary to prescribe such rules and regulations as may be necessary to carry out such provisions. Further, the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) reemphasized the Secretary's royalty management authorities and responsibilities for Federal, OCS, and Indian oil and gas leases. Section 301(a) of FOGRMA, 30 U.S.C. 1751(a), says ''The Secretary shall prescribe such rules and regulations as he deems reasonably necessary to carry out this Act.''

Also, the royalty clauses of Federal oil and gas leases say that the Secretary of the Interior may establish reasonable minimum royalty values (considering highest prices paid for part or a majority of like-quality production in the same field, prices received by the lessee, posted prices, and other relevant matters, and, whenever appropriate, after notice and opportunity to be heard). Thus, MMS believes this rulemaking effort complies with both the letter and spirit of the statutes and lease terms.

MMS addressed the Unfunded Mandates Reform Act, the Paperwork Reduction Act, Executive Order 12630, and Executive Order 12866 in the February 1998 proposal and does so again in Section XI of this preamble.

(q) Interim Final Rule

MMS indicated that it might publish an Interim Final Rule while it evaluated the methodology in the proposed rule. This approach would provide the flexibility to do a revision after the first year without a new rulemaking.

Summary of Comments: Twenty respondents commented on this approach. All commenters opposed the issuance of an Interim Final Rule, indicating that such a rule would be overly costly and burdensome to both industry and MMS, especially if MMS later changed the valuation standards.

MMS Response: MMS has abandoned the notion of an Interim Final Rule for this rulemaking and is publishing a Final Rule instead.

(r) Alternatives

Summary of Comments: Fifty commenters suggested one or more alternatives to the proposed rules. The leading alternative by far was the recommendation that MMS take and market its royalty share in kind. Other alternatives revolved around modifying the existing non-arm's-length valuation benchmarks.

Almost all industry commenters and some State commenters recommended that MMS expand its current RIK program. Two industry trade organizations indicated that MMS would benefit from an RIK program thus ending valuation controversies. MMS would further benefit by earning the higher rewards that the market holds for successful risk-takers. Several commenters recommended that MMS model its RIK program after that of Alberta, Canada. One State suggested using RIK sales to determine marketing/location differentials and to obtain comparable sales information to value oil not disposed of at arm's length. Commenters generally believed that an RIK program would be less burdensome on industry, would reduce MMS's administrative costs, and would ensure proper valuation. Some suggested that MMS auction the RIK oil at the lease to gain the best price.

Several commenters suggested revising the existing non-arm's-length valuation benchmarks to eliminate reliance on posted prices but still maintain benchmarks. Besides deleting references to posted prices, suggestions included arranging the benchmarks as follows:

- Prices received by the lessee under other comparable arm's-length transactions in the same field or area, including prices bid in response to tendering programs.
- Arm's-length prices received by others in the field.
- Prices from nearby fields within an area acceptable to MMS.
- Prices received by MMS, adjusted to the lease, from its sales of RIK oil from the field.
- A netback method, perhaps based on index prices, adjusted back to the lease.

One industry commenter suggested using the average of posted prices to establish the benchmark value. One State commenter indicated that netting back is the only valid indicator of market value for integrated companies.

MMS Response: MMS does not believe that taking all Federal oil in kind is in the best interests of the American public or that such a program would enhance royalties. MMS already has the authority under existing law and lease agreements to take royalty in kind when it would be beneficial to the taxpayer. We believe it would be a mistake to require all Federal oil to be taken in kind. For example, the taking of de minimus production in remote areas could lead to substantial revenue losses. MMS intends to continue its existing royalty-in-kind programs to determine where and how it can most effectively use its authority to take royalties in kind. This will result in the best overall return to the American public.

Several of the suggested revisions to the non-arm's-length valuation benchmarks revolve around finding comparable sales transactions. But commenters have not demonstrated the consistent existence or availability of such transactions for volumes sufficient to use for royalty valuation. To the contrary, MMS believes that nationwide about two-thirds of crude oil production is disposed of non-arm's-length. As previously mentioned, the general lack of competitive and transparent markets at the lease makes the attempt to find comparable sales transactions far inferior to the use of index prices. The RMR, where reliable spot prices are not readily available, is an exception—about two-thirds of crude oil produced there is sold at arm's length. In addition, this proposal has substantial practical difficulties since companies are not privy to comparable sales transactions and such information available to MMS is unaudited for current periods. The final rule thus primarily uses index prices, adjusted for location and quality, to establish value for oil not sold at arm's length. As indicated above, MMS has concluded that posted prices no longer reflect market value, so any scheme using posted prices would not accomplish the goal of this rulemaking.

General Comment—MMS Consultants. Aside from the topical categories discussed above, we received several comments throughout the rulemaking process that MMS relied too heavily on reports by consultants with predisposed positions. However, in developing this rule, MMS sought out the best experts available to advise it on the petroleum market. These experts provided MMS with valuable information on current and past marketing practices. Further, analyses of the industry consultants' comments by MMS's consultants (Review of Selected Technical Reports on MMS's Proposed Federal Oil Rule and Supplemental Rule, Innovation & Information Consultants, Inc., September 25, 1997) suggest that many arguments have multiple perspectives and are equivocal. MMS appreciates these different viewpoints and considered them in deliberating on this rulemaking.

IV. Responses to Public Comments on July 1997 Proposal

Summary of Proposed Rule

The primary purpose of the July 1997 proposal was to revise the eligibility requirements for oil valuation under arm's-length transactions. (See (b) below.) Specifically, the supplementary proposal:

• Expanded gross proceeds valuation to dispositions involving competitive crude oil calls,

• Extended index pricing valuation to ''overall balance'' situations,

• Deleted the requirement to value oil using index prices for lessees who purchased oil in the last 2 years, and

• Added language to value oil subject to a single exchange agreement under either the arm's-length gross proceeds accruing after the exchange or the index pricing method.

MMS also asked for further comments on collecting information on proposed Form MMS–4415 and reopened the comment period on the January 1997 proposal.

We received over 270 pages of written comments from 27 entities, including independent oil and gas producers, major oil and gas companies, petroleum industry trade associations, States, a municipality, consultants, and futures market representatives. Comments fell into 11 topical categories ((a) through (k) below). Many of the respondents reiterated or expanded on the same comments made on the January 1997 proposal.

(a) Posted Prices

Summary of Comments: Two respondents submitted further comments on posted prices. Both agreed that posted prices no longer reflect market value. One commenter cautioned, however, that any use of gross proceeds to establish value (specifically in California) will result in royalties being paid on posted prices, since most outright sales contracts are tied to posted prices.

MMS Response: For the reasons expressed in sections I and III(b), the final rule eliminates posted prices as an indicator of crude oil value for royalty purposes. However, MMS still believes that, even in California, proceeds received by a lessee or its affiliate under an arm's-length contract represent market value. Only when oil is not sold at arm's length is it necessary to look to other reliable indicators to determine value.

(b) Revisions to Arm's-length Valuation Criteria (Revised Proposed Paragraphs 206.102(a)(4) and (a)(6))

Based on comments that the proposed rule overly restricted the use of arm's-length gross proceeds as royalty value, the July 1997 proposal expanded the arm's-length valuation criteria in proposed paragraph 206.102(a)(4) by reducing the exclusions to only those situations involving (1) a sales contract that does not reflect the total consideration for the value of production, (2) a breach in the duty of the lessee to market production for the mutual benefit of the lessee and the lessor, (3) certain exchange agreements, (4) non-competitive crude oil calls, and (5) maintenance of overall balances between buyer and seller. For oil disposed of under a single arm's-length exchange agreement, MMS offered two options (revised proposed paragraph 206.102(a)(6)): (1) the index pricing method, or (2) the gross proceeds received in an arm's-length sale of the oil acquired in the exchange. MMS also deleted the requirement that lessees use the index pricing method if they purchase oil within 2 years preceding the production month, commonly referred to as the ''two-year rule'' which was initially proposed as paragraph 206.102(a)(6).

Summary of Comments—MMS Assumptions and Rationale: Sixteen respondents commented on MMS's underlying assumptions and rationale leading to the proposed revisions. Some thought the changes were in the right direction but, along with other commenters, believed the overall concept of index pricing and valuation away from the lease remained flawed because of the prevalence of active lease markets. A few commenters noted that the index pricing method is not applicable to Rocky Mountain oil because this oil stays in the RMR and its prices are not influenced by NYMEX trades.

MMS Response: As discussed in Section III(g) and (h), index prices are often used in the negotiation of sales and settlement prices. They provide a reliable indicator of market value when oil is not sold at arm's length. For the RMR, however, the final rule contains a series of benchmarks for valuing oil not sold at arm's length. The first two of these benchmarks are not related to index prices. The third of these benchmarks is an index price—the Cushing, Oklahoma, spot price for WTI (adjusted for quality and location). MMS selected that price because it is closest to most of the RMR and is used in some exchange agreements involving oil produced in that region. However, under paragraph 206.103(b)(5) of the final rule, if the lessee believes that the first three benchmarks do not result in a reasonable value for its production, the MMS Director will establish an alternate valuation method.

Summary of Comments—Overall Balance: One commenter believed the restriction on ''overall balances'' (proposed paragraph 206.102(a)(4)(ii)) is based upon an unproven and faulty assumption that reciprocal dealings are anti-competitive. Three commenters questioned the meaning of ''market value in the field or area'' regarding the limitation on overall balances. They believed the inclusion of this phrase would create confusion and litigation because despite the requirements to use index pricing in overall balance situations, companies might reason that the contract price nonetheless represents market value. Two commenters feared that MMS's use of this phrase would open the door to the use of a comparable sales methodology, which they opposed. One commenter recommended that MMS modify the regulatory language on overall balance situations to provide:

1. That index-based value be used where the arm's-length contract is subject to an informal or formal overall balance agreement maintained between the buyer and seller.

2. That there is a rebuttable presumption that an overall balance arrangement exists where the lessee has purchased oil (or gas or other gas or petroleum-related products) from its buyer within the last 2 years.

3. That the rule does not apply for oil purchased to meet production shortfalls or for lease operations.

Four commenters thought that a new certification to verify that a lessee is not maintaining an ''overall balance'' with its purchaser is unnecessary because Form MMS–2014 already certifies that values are true and accurate. They also suggested that ''overall balance'' be defined.

MMS Response: MMS removed the language regarding overall balances as a separate, specific provision in the February 1998 proposal and in the final rule. However, oil subject to overall balance situations will be examined in view of paragraphs 206.102(c)(1) and (c)(2) to determine whether the prices received represent market value. The value of oil involved in overall balancing agreements thus ultimately will be the lessee's total consideration or the value determined by the non-arm's-length methods in § 206.103.

Several commenters said in response to the February 1998 proposal that removing the overall balance provision and relying on MMS to find such agreements put an undue burden on MMS. They further stated that MMS would have great difficulty verifying the existence of such agreements. We continue to believe, however, that verification of overall balancing arrangements, and appropriate follow up, is best left to audit and the provisions of paragraphs 206.102(c)(1) and (c)(2).

Summary of Comments—Two-Year Rule: Two commenters opposed MMS's deletion of the ''two-year rule.'' One commenter argued that deleting this rule will cause difficult compliance problems because of the difficulty in tracing all two-party transactions and in determining the existence of overall balancing arrangements, many of which may be informal. To address the concerns of independent producers, two commenters recommended the 2-year rule be modified to exclude purchases of minimal amounts of crude oil for lease operations or to make up production shortfalls.

MMS Response: As discussed in Section III(d) above, MMS removed the 2-year rule because it was overly restrictive.

(c) Crude Oil Calls (Revised Paragraph 206.102(a)(4)(iii))

For oil disposed of under a crude oil call, the July 1997 proposal would recognize gross proceeds as value only if the price paid is the same as what other parties are willing to competitively bid to purchase the oil (the so-called ''Most Favored Nations'' clause). Otherwise, oil disposed of under a non-competitive crude oil call would be valued by index pricing methods.

Summary of Comments: Nine respondents commented on the crude oil call issue. There was general agreement to allow arm's-length sales of oil subject to unexercised crude oil calls to be valued based on gross proceeds. However, several commenters representing both State and industry interests expressed concern about the Most Favored Nations (MFN) clause. Four industry commenters disagreed that a crude oil call must contain a MFN clause for the sale of oil under the call to be considered arm's length. Commenters representing States, on the other hand, opposed treating contracts with crude oil calls with MFN or other escalation clauses as arm's-length, arguing that:

- The existence of an MFN clause in a contract does not mean the associated price was derived from a true arm's-length interaction.
- Acceptance of prices under MFN or other escalation clauses increases the potential to use oil postings as the basis for value.
- MMS will have difficulty in monitoring MFN transactions.

Industry commenters recommended deleting reference to MFN altogether because such clauses are more common to gas contracts and rarely, if ever, are used in oil transactions. Industry commenters also generally opposed any exclusion of crude oil calls from arm's-length consideration, arguing that calls are legitimate business transactions and that MMS has the option to use benchmarks if call prices are suspect.

MMS Response: MMS recognized in the July 1997 proposal that not all crude oil calls are exercised and that some calls are subject to competitive bid. In the February 1998 proposal, MMS modified the rules regarding competitive crude oil calls to accept arm's-length gross proceeds as value in these situations. In the final rule, MMS removed the language regarding noncompetitive crude oil calls as a separate, specific provision. However, oil subject to a noncompetitive crude oil call will be examined in view of paragraphs 206.102(c)(1) and (c)(2) to determine whether the prices received represent market value. The value of oil involved in a noncompetitive crude oil call thus ultimately will be the lessee's total consideration or the value determined by the non-arm's-length methods in § 206.103.

(d) Valuing Oil Disposed of Under Exchange Agreements (Revised Proposed Paragraph 206.102(a)(6))

The July 1997 proposal extended the use of gross proceeds valuation to oil exchanged and sold at arm's length after a single exchange. In those cases where a lessee disposes of the produced oil under an exchange agreement with a non-affiliated person, and after the exchange the lessee sells at arm's length the oil acquired in the exchange, the lessee would have the option of using either its gross proceeds under the arm's-length sale or the index pricing method to value the lease production (proposed paragraph 206.102(a)(6)(i)). If the lessee chose gross proceeds under this option, the lessee would have to value oil production disposed of under all other arm's-length exchange agreements in the same manner (proposed paragraph 206.102(a)(6)(iii)). For any oil exchanged or transferred to affiliates, or subject to multiple exchanges, the lessee would have to use the index pricing method to value the lease production (proposed paragraph 206.102(a)(6)(ii)).

Summary of Comments: Ten respondents commented on the rules governing the valuation of oil disposed of under exchange agreements. Commenters supporting the amended proposal did so with reluctance. They believed the option to use gross proceeds would create compliance problems resulting from the necessity to trace and verify the nature of the exchange. One commenter suggested that MMS expand the gross proceeds option to apply to a single exchange by the lessee or its affiliate where all the oil received under that exchange is sold at arm's length. Two commenters suggested giving the lessee an option of valuing exchanged oil by using either lease-market benchmarks (rather than index prices) or the lessee's resale price less an exchange differential, regardless of the number of exchanges needed to reposition the crude oil for sale. Some commenters recommended excluding all exchange agreements from gross proceeds valuation, as MMS initially proposed.

MMS Response: In the February 1998 proposal, MMS expanded gross proceeds valuation to include situations where the oil received in exchange is ultimately sold at arm's length, regardless of the number of exchanges involved. However, many industry comments claimed that tracing multiple exchanges would be overly burdensome, while others wanted the ability to use the ultimate arm's-length gross proceeds. As a result, and as explained in more detail in Section VI(e) of this preamble, in the final rule MMS is providing an option to use either the arm's-length gross proceeds following one or more arm's-length exchanges, or the provisions of § 206.103. The chosen option will apply for at least 2 years. The lessee must use this method to value all of its crude oil produced on a property basis—that is, from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that the lessee or its affiliate sells at arm's length following one or more exchanges. (See Section IX (i) of this preamble for the reasons why the final rule changes to a property basis for this exception.) The provisions of § 206.103 will apply for oil that is not sold at arm's length after the exchange and for oil subject to non-arm's-length exchanges regardless of whether an arm's-length sale follows such an exchange.

(e) NYMEX Pricing (Initial Proposed Paragraph 206.102(c)(2)(i))

Summary of Comments: Nine respondents submitted further comments on the NYMEX pricing methodology proposed in the January 1997 proposal. Industry commenters reiterated their opposition to the methodology. Two commenters noted that NYMEX did not represent the market in California or Wyoming. However, one commenter defended the NYMEX market as a useful pricing reference for the oil industry. Contrary to industry's allegations that the NYMEX market is dominated by speculators, this commenter indicated that commercial oil entities account for 75 to 80 percent of market participation.

MMS Response: As discussed in Section III(g), MMS has abandoned the use of NYMEX prices as an indicator of crude oil value.

(f) ANS Spot Prices (Initial Proposed Paragraph 206.102(c)(2)(ii))

Summary of Comments: Three industry commenters reiterated industry's general opposition to using ANS spot prices as the basis for crude oil valuation in California and Alaska. They argued that ANS spot prices are an invalid measure of California crude oil value because:

- The quality differences between ANS and California crudes are too great;
- ANS is a thinly-traded market; and
- ANS crude commands a higher price not only because of its superior quality but also because of its consistent availability to California refiners to satisfy marginal demands.

Commenters representing the State of California continued to support the ANS valuation method for that State.

MMS Response: For the reasons expressed in Section III(h), MMS maintains that the ANS spot price is a valid indicator of value for crude oil produced in California.

(g) Duty To Market (Initial Proposed Paragraph 206.102(e)(1))

Summary of Comments: Seven respondents, five representing industry and two representing States, submitted further comments on the rule requiring lessees to market crude oil production at no cost to the Federal Government. Industry commenters repeated their opposition to this rule using the same reasons summarized for the January 1997 proposal. However, State representatives supported the rule. One State commenter indicated that industry does not include marketing costs in determining location and quality differentials; therefore, industry should not be allowed to include marketing costs in determining the differentials for royalty purposes.

MMS Response: For the reasons expressed in Section III(i), MMS maintains its position that lessees have a duty to market production without cost to the Government.

(h) Requiring Use of Actual Transportation Costs (Amended § 206.105)

Summary of Comments: Four respondents submitted further comments on the proposed removal of the exception regarding transportation allowance calculations based on actual costs. Industry commenters reiterated their opposition, while State commenters supported the proposal.

MMS Response: As explained in Section III, in the final rule MMS has deleted the provision for a lessee to apply for an exception to use FERC tariffs in lieu of actual costs.

(i) Form MMS–4415 (Proposed Paragraph 206.105(d)(3)) and Differentials

The July 1997 proposal clarified MMS's intended use of Form MMS–4415 in two respects: (1) MMS will calculate specific differentials as the volume-weighted average of the individual differentials derived from the information reported on the form and (2) MMS will collect only information about exchanges where delivery occurs at an aggregation point and a market center (*i.e.,* lessees will not be required to report information for exchanges occurring at the lease). MMS requested comments on the usefulness of collecting information about exchanges between two aggregation points. MMS also requested comments on how lessees would allocate to Federal leases differentials from aggregation points to market centers when non-Federal production is commingled with Federal production at aggregation points.

Summary of Comments: Six respondents, five representing industry and one a local government, gave additional commentary on Form MMS–4415. Few commenters responded directly to MMS's specific requests for comments on collecting information about exchanges between two aggregation points and allocating differentials when non-Federal production is commingled with Federal production at aggregation points. None gave substantive suggestions. Comments essentially duplicated those provided in response to the January 1997 proposal. Comments ranged from outright opposition to the form (and its data collection requirement) to complaints about its administrative burden and lack of clear instructions.

MMS Response: As discussed in Section III(m), MMS eliminated Form MMS–4415 in the final rule.

(j) Fairness, Procedural Conduct, and Workability

Summary of Comments: Ten respondents commented on this topic. Industry commenters continued to oppose any valuation scheme that they assert moves the point of royalty valuation away from the lease, reiterating their arguments that the index pricing methodology would not reflect market value at the time of production, would be costly and difficult to administer, and is contrary to lease terms and statutory mandates. They maintained their position that the value of oil disposed of under non-arm's-length conditions should be based on comparable transactions in the same field or area. Two commenters representing a State's interests criticized MMS for expanding the arm's-length gross-proceeds valuation criteria.

MMS Response: We responded to these comments throughout other sections of this preamble.

(k) Alternatives

Summary of Comments: Eleven respondents (ten industry and one governmental advisory group) gave further comments on alternatives to the proposed rule. Industry commenters reiterated their position that MMS should either take its oil in kind (the most prevalent comment), modify the current benchmarks to eliminate reference to posted prices, or base value on some form of comparable sales from the same field or geographic area. However, related to an idea discussed in earlier public workshops, commenters said that a comparable sales valuation method based on data reported to MMS would be unworkable because of the limitations of MMS's computer system (MMS cannot sort the data by field nor determine significant quantities) and because much of the sales data reflects posted prices.

MMS Response: We responded to these comments in detail in Section X and in Section III(r).

V. Responses to Public Comments on September 1997 Notice

Summary of Proposed Alternatives

The September 1997 notice reopened the public comment period on the January 1997 proposal and requested comments on five alternatives to value oil disposed of under non-arm's-length conditions: (1) A value based on prices received under bid-out or tendering programs; (2) a value determined from benchmarks using arm's-length transactions, RIK sales, or a netback method; (3) a value based on geographic indexing using MMS's own system data, but excluding posted prices; (4) a value based on index (NYMEX and ANS) prices but using fixed-rate differentials; and (5) a value using published spot prices instead of NYMEX prices. With regard to Alternatives 1, 2, and 3, we asked whether the RMR should have separate and specific valuation standards.

We received written comments from 28 entities, including independent oil and gas producers, major oil and gas companies, petroleum industry trade associations, States, a municipality, a government oversight group, and a royalty owner. Numerous individuals provided commentary at the public workshops. We summarized the comments on the proposed alternatives in the February 1998 proposal. We repeat the comment summaries here and give our responses.

(a) Alternative 1—Bid-Out or Tendering Program

Summary of Comments: Industry and some States supported tendering as a viable method to determine royalty value. They reasoned that the prices received under tendering transactions were evidence of market value at or near the lease, which satisfies the rulemaking objective. However, industry cautioned that tendering would not be applicable in every situation (it would be too expensive for some companies to develop and administer) and should be one of the other alternatives available for valuation. In fact, two commenters noted that tendering-based valuation was not feasible in California because no one is presently engaged in tendering programs in that State. To be acceptable for valuing the lessee's non-arm's-length production, one commenter recommended that the minimum tendered volume should be MMS's royalty share plus 2 percent, or if transported by a truck or tank car, a volume equal to a full load; another commenter recommended 10 to 20 percent as the minimum volume, with a minimum of three bids.

MMS Response: MMS did not adopt this alternative as there are meaningful spot prices applicable to production in all areas other than the Rocky Mountains. Further, tendering occurs in relatively few cases now and thus generally does not reflect true market value.

With the exception of the RMR, spot and spot-related prices drive the manner in which crude oil is bought and traded in the U.S. Spot prices play a major role in crude oil marketing and are readily available to lessees through price reporting services. We believe spot prices are the best indicator of the value of production. Thus, with the exception of the Rocky Mountains, we don't believe it is necessary to use other less accurate and more administratively burdensome means of valuing production not sold at arm's length (e.g., tendering).

MMS adopted a particular tendering alternative designed with what MMS intends as safeguards against manipulation as a benchmark for the RMR for production not sold at arm's length because of the lack of a reliable spot price in that region. One of the Rocky Mountain State commenters recommended this method as the initial benchmark in that region. MMS has acquiesced in that recommendation but nevertheless has substantial concerns about the potential for manipulation of tendering programs. MMS intends to closely monitor the reliability and workability of this benchmark.

MMS's response to the comments regarding minimum volume and bid requirements is provided in Section VI below.

(b) Alternative 2—Benchmarks

Summary of Comments: Industry and some States generally supported some form of benchmark system based on actual arm's-length sales, RIK prices, or a netback method using an index price or affiliate's resale price to value oil not disposed of at arm's length. (Nonetheless, many commenters remained opposed to NYMEX- and ANS-based pricing.) Industry, however, advocated that lessees be permitted to select the valuation method best suited to their situation; in other words, they wanted the benchmarks to be a menu, rather than a hierarchy. States objected to this selection concept. Industry also urged MMS to abandon the requirement that royalty value is the greater of the lessee's gross proceeds or the benchmark value.

One State recommended separate valuation standards for lessees with affiliated refiners and those without. For lessees with affiliated refiners, value would be determined by benchmarks using tendered prices, lease-based comparable sales, and netback from spot price. (This suggestion was directed to the RMR only.) For lessees without affiliated refiners, but who have a marketing affiliate that sells the lessee's oil outright or in a buy/sell exchange, royalty would be due on the resale value less appropriate allowances. Industry objected to this affiliated-refiners distinction because not all producers in integrated companies sell or transfer their oil production to their affiliated refiner.

For netback valuation, industry urged MMS to recognize all costs associated with midstream marketing as allowable deductions from the index or resale price. However, one State commenter argued that industry has failed to demonstrate any entitlement to a marketing deduction as a matter of law or fact, citing, for example, that midstream marketing costs are already factored into transportation tariffs and location differentials.

Two commenters representing State of California interests objected to any benchmark valuation scheme for that State. They argued that the California crude oil market is not competitive. Thus, they believed that any non-arm's-length valuation scheme based on arm's-length prices would not reflect true market value. They maintained that

ANS prices are the only viable method of valuing crude oil in California.

MMS Response: In the final rule, MMS adopted a series of benchmarks for valuing RMR production not sold at arm's length. However, for the reasons explained above, the final rule does not use those benchmarks for the rest of the country; we apply spot prices in those regions. The Rocky Mountain benchmarks prescribe a first benchmark, but if it does not apply, the lessee has the choice of two other benchmarks. A lessee must use the first benchmark if it applies to the lessee's situation—that is, tendering—and if tendering does not apply, then it may choose between a weighted average of arm's-length sales and purchases, or Cushing, Oklahoma, adjusted spot prices. If the lessee demonstrates that none of the three benchmarks establish a reasonable value, MMS may establish an alternative valuation method.

MMS agreed with the industry comment that we should not require royalty value to be the higher of gross proceeds or the benchmark value. Hence, the final rule does not require royalty value to be the higher of gross proceeds or index price.

While the final rule does not make a distinction between lessees with affiliated refiners and those without, it does establish different valuation methods for oil that is sold at arm's length versus oil that is not. The distinction is based on the disposition of the oil and not a lessee's ownership of a refinery.

Comments regarding costs of midstream marketing are addressed in Section III(i).

(c) Alternative 3—Geographic Indexing

Summary of Comments: Most commenters believed a geographic fixed index method would be unworkable. They mainly objected to the time difference between the production month and publication of the index price. They argued that the published indices would always be out-of-date and require unnecessary adjustments for prior reporting months.

MMS Response: MMS agrees with commenters that a geographic fixed index would be unworkable and, therefore, the final rule does not use this method. Additional MMS responses to this alternative are contained in our detailed responses to comments in Section XI, Executive Order 12866, later in this preamble.

(d) Alternative 4—Differentials

Summary of Comments: In concert with their objections to basing value on index (NYMEX and ANS) prices away from the lease, industry commenters opposed the use of any fixed (or other) differentials that don't permit deductions for midstream marketing activities. Specifically for California, two commenters representing State interests urged MMS to use the gravity factor in the Four Corners and All American Pipeline tariffs to adjust for quality differences between ANS and California crude oils. For location differentials, they reiterated their position that the only relevant information is from ''in/out'' exchanges. As an alternative to determining separate location differentials for the various California aggregation point/market center pairs, they proposed fixed-rate differentials for given geographic zones.

MMS Response: MMS agrees with industry and most State commenters that the proposed fixed differentials would be unworkable and, therefore, the final rule does not use this method. The February 1998 proposal and the final rule added paragraph 206.112(e) allowing for the use of quality banks including the gravity factor suggested by one State commenter. The final rule uses the location and quality differentials contained in arm's-length exchange agreements (including ''in/out'' exchanges) to adjust index prices for location and quality. Additional MMS responses to this alternative are contained in our detailed responses to comments in Section XI, Executive Order 12866, later in this preamble.

(e) Alternative 5—Spot Prices

Summary of Comments: Comments on the proposed spot price methodology were mixed. Some commenters thought it was a workable approach, but indicated that the net result would be the same as starting with a NYMEX price and adjusting back to the lease. A few commenters noted that spot prices are published only for a limited number of domestic crude oils, and no spot prices are published for the RMR. One commenter questioned the accuracy of the reported prices. Industry commenters remained concerned with the disallowance of marketing costs in any netback scheme.

MMS Response: For regions other than the Rocky Mountains, the final rule uses spot prices to establish value for production not sold at arm's length. In the RMR, spot prices are used as a third benchmark. Additional MMS responses regarding use of spot prices are contained in detail in Section VI(e).

(f) Rocky Mountain Region

Summary of Comments: There was general consensus that the RMR exhibited particular oil marketing characteristics that would justify different royalty valuation standards. Some commenters, both industry and State, supported the notion of separate valuation standards for the region. Others, however, disagreed with any regional separation, preferring instead a single, nationwide valuation scheme or menu of benchmarks.

MMS Response: We agree with the general consensus that a separate valuation method is needed for the RMR. The final rule incorporates this change.

VI. Responses to Public Comments on February 1998 Proposal

Summary of Proposed Rule

In response to comments received on the prior proposed rules and comments made at the public workshops, the February 1998 proposal contained substantive changes to the valuation procedures included in the January 1997 proposal. For oil that ultimately is sold in an arm's-length transaction, the royalty value would be the gross proceeds accruing to the seller under the arm's-length sale. This procedure would apply to arm's-length exchanges where the oil received in exchange is ultimately sold at arm's length. It would also apply to oil sold in the exercise of competitive crude oil calls.

For oil (or oil received in exchange) that is refined without being sold at arm's length, for oil disposed of under non-arm's-length exchange agreements and non-competitive crude oil calls, and for all other oil not sold at arm's-length, the royalty value would be determined by measures prescribed for three geographic regions. For oil produced in California and Alaska, value would be based on ANS spot prices, adjusted for location and quality. For oil produced in the RMR, value would be determined by the first applicable of four benchmarks: (1) The highest price bid for tendered volumes, (2) the volume-weighted average of gross proceeds accruing under the lessee's or its affiliate's arm's-length contracts for the purchase or sale of crude oil from the field or area, (3) the average NYMEX futures prices, with location and quality adjustments, and (4) an MMS-established method. For oil produced outside of California, Alaska, and the Rocky Mountain Area, value would be the average of the daily mean spot prices published for the nearest market center, adjusted for location and quality differentials.

The February 1998 proposal also contained specific instructions for reporting on Form MMS–4415, modified certain definitions, and added others. It reiterated the lessee's duty to put the production in marketable condition and to market the production at no cost to the lessor. Rules addressing transportation allowances were recodified in new sections and modified to reflect the newly-proposed valuation rules.

We received almost 700 pages of written comments from 35 entities, including independent oil and gas producers, major oil and gas companies, petroleum industry trade associations, States, a municipality, small refiners, and consultants. Consistent with its past comments, industry generally opposed the proposed rules, arguing that they do not offer certainty, do not reduce administrative costs, and particularly do not derive a reasonable value of production at the lease. Industry particularly maintained its advocacy of using so-called ''lease markets'' (arm's-length sales of like-quality production in the same field or area) to set value of production not disposed of at arm's length. States generally supported the rule but had suggestions for changes.

Several commenters continued to address many of the same issues. They include:

- Duty to market,
- Restrictions on gross proceeds valuation,
- Using NYMEX index prices and ANS spot prices for non-arm's-length valuation,
- Treatment of non-competitive crude oil calls,
- Eliminating the exception allowing requests to use FERC tariffs instead of actual transportation costs, and
- Use of differentials to calculate royalty value.

Comments on these issues were not substantively different from those previously summarized. Rather than repeating the issues and comments here, we refer the reader to Sections I, III, IV, and V above. Instead, we only address comments on those provisions that are new to or revised from the previous proposals. Comments are grouped into seven topical categories ((a) through (g) below).

(a) Definitions (Proposed § 206.101)

Affiliate—Summary of Comments: Eleven respondents, all representing industry, objected to the 10 percent ownership threshold for defining control and thus requiring non-arm's-length valuation. They argued that 10 percent was too low because affiliates with this small amount of ownership actually have no control over the affiliated entity. Accordingly, they believed that too many lessees would be excluded from using their gross proceeds in bona fide arm's-length transactions as value. Others suggested retaining the current definition of affiliate, as defined by the term ''arm's-length contract,'' where ownership of 10 percent through 50 percent creates a presumption of control. One commenter suggested 20 percent to 50 percent ownership as the criteria for creating a presumption of control, consistent with the definition used by the Bureau of Land Management. One commenter suggested deleting reference to partnerships and joint ventures because lessees might not have access to records of these entities and these terms could create confusion as to whether the affiliate test applies to the property, field, or corporate level.

MMS Response: In this final rule, we have made ''affiliate'' a separate definition from ''arm's length.'' We believe this clarifies and simplifies the definitions and should promote better understanding of both ''arm's length'' and ''affiliate.''

In the final rule, MMS is revising the definition of ''affiliate.'' The July 1998 proposal (63 FR at 38356) retained the criteria for determining affiliation that are contained in the existing rule. The March 1999 notice that included the August 31, 1998 letter from the Assistant Secretary for Land and Minerals Management to the Senate (64 FR at 12268) also indicated that MMS likely would retain the same criteria that are in the existing rule.

In response to the March 1999 notice, industry commenters proposed a set of criteria which lessees could use to rebut the presumption of control that arises from ownership or common ownership of between 10 and 50 percent. While MMS does not agree with the industry proposal, a judicial decision in a case decided after the close of the comment period for the March 1999 notice affects the criteria for determining control and the associated presumption in the existing rule.

In *National Mining Association* v. *Department of the Interior*, 177 F.3d 1 (D.C. Cir. 1999) (decided May 28, 1999), the United States Court of Appeals for the District of Columbia Circuit addressed the Office of Surface Mining Reclamation and Enforcement's (OSM's) so-called ''ownership and control'' rule at 30 CFR 773.5(b). That rule presumed ownership or control under six identified circumstances. One of those circumstances was where one entity owned between 10 and 50 percent of another entity. The court found that OSM had not offered any basis to support the rule's presumption ''that an owner of as little as ten per cent of a company's stock controls it.'' 177 F.3d at 5. The court continued, ''While ten percent ownership may, under specific circumstances, confer control, OSM has cited no authority for the proposition that it is ordinarily likely to do so.'' *Id.* (Emphasis added.) In a footnote, the court referred to the existing MMS rule:

> In its brief OSM referred the court to several regulations promulgated by other agencies but none of them presumes control based simply on a ten percent ownership stake, although another Department of Interior regulation does so. See 30 C.F.R. 206.101(b) [sic] (''based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: * * * (b) Ownership of 10 through 50 percent creates a presumption of control''). We do not consider the validity of section 206.101 here.

Id. The United States did not file a petition for rehearing. Nor did the United States seek Supreme Court review.

In the final rule, MMS is revising the definition of ''affiliate'' in light of the National Mining Association decision. In the event of ownership or common ownership of between 10 and 50 percent, paragraph (2) of the definition in the final rule, instead of creating a presumption of control, identifies a number of factors that MMS will consider in determining whether there is control under the circumstances of a particular case.

With respect to ownership or common ownership, the new definition identifies such factors as the percentage of ownership, the relative percentage of ownership as compared with other owners, whether a person is the greatest single owner, and whether there is an opposing voting bloc of greater ownership. All of these are relevant factors in determining whether there is control in a particular case.

For example, company A could own one third of the voting stock of company B, while no other owner owns any percentage close to that. A is the greatest single owner, and it is very likely that A has control of B. If, in addition, A manages the day-to-day operations of B and the other owners effectively are passive investors, it would be very clear that A controls B and that they are affiliates.

A different example would be if A owns 20 percent of B, at the same time that C and D each own 35 percent of B. In such a case, it would be much harder to demonstrate that A controls B, and doing so would depend on additional facts that would show that A has effective control.

Yet another example would be if A owns 12 percent of B and other owners own roughly equivalent percentages of B. A may or may not control B, again depending on what additional circumstances are present.

We emphasize that simply because one entity is found not to control another on the basis of stock ownership and other factors, and therefore that the entities are not affiliates, that does not always mean that the relationship between the two entities is at arm's length. The entities may be engaged in a cooperative venture and therefore not have opposing economic interests. (An example is the situation in Xeno, Inc., 134 IBLA 172 (1995), in which a number of lessees in a large field combined to form another entity to purchase their gas, then gather, compress, and treat it, and then resell it to another purchaser.)

Paragraph (2) of the definition also identifies other factors in addition to ownership interests that are relevant to determining control. These include the extent of common officers or directors, operation by one entity of a lease or a facility, the extent of participation by different owners in operations and day-to-day management of an entity, and other evidence of power to exercise control or common control. These factors will be evaluated on a case-by-case basis.

Paragraphs (1) and (3) of the definition continue the existing provisions that ownership of more than 50 percent constitutes control, that ownership of less than ten percent constitutes a presumption of noncontrol, and that relatives, either by blood or marriage, are affiliates regardless of any percentage of ownership or common ownership. The National Mining Association decision does not affect these provisions.

Gross proceeds—Summary of Comments: Two industry commenters opposed the inclusion of payments made to reduce or ''buy down'' the purchase price of oil to be produced in later periods in the revised definition of ''gross proceeds.'' One commenter argued that the collection of royalty on buydowns was contrary to the decision in *IPAA* v. *Babbitt*, 92 F.3d 1248 (D.C. Cir. 1996).

MMS Response: The implications of the D.C. Circuit's ruling in the IPAA case, as well as the Sixth Circuit's decision in *United States* v. *Century Offshore Management Corp.*, 111 F.3d 443 (6th Cir. 1997), cert. denied, 522 U.S. 1090 (1998), and other subsequent court decisions regarding ''buydown'' payments (which in recent years have been part of contract settlement arrangements) are analyzed in two recent decisions of the Assistant Secretary for Land and Minerals Management in Mobil Oil Corp., Docket Nos. MMS–94–0151-OCS, 94–0668-O&G, 94–0669-O&G, 95–0063-O&G, and 95-0065-O&G (consolidated) (May 4, 1998), and Antelope Production Co., Docket No. MMS–96–0068-O&G (May 4, 1998). For the reasons explained in those decisions, the definition of ''gross proceeds'' contained in the February 1998 proposal and in the final rule is fully in accordance with law.

Rocky Mountain Area—Summary of Comments: Six respondents (five industry and one State) commented on the definition of ''Rocky Mountain Area.'' Industry commenters believed the word ''Area'' should be changed to ''Region'' to avoid confusion with the definition of ''area.'' They also suggested including northwest New Mexico (*i.e.*, the San Juan Basin) in the Rocky Mountain Area. The State commenter, however, opposed including northwest New Mexico in the definition because crudes from the San Juan Basin are regularly exchanged in midcontinent markets.

MMS Response: MMS agrees with the comment that the term Rocky Mountain ''Area'' should be changed to Rocky Mountain ''Region.'' We made this change in the final rule. We concur with the commenter from the State of New Mexico that northwest New Mexico should not be part of the RMR because crude oil from the San Juan Basin is regularly exchanged or sold in midcontinent markets. For the same reasons, the final rule excludes from the RMR definition those portions of the San Juan Basin, and other oil-producing fields in the ''Four Corners'' area (*i.e.*, near the convergence of the boundaries of New Mexico, Arizona, Utah, and Colorado) that lie within the States of Colorado and Utah. Crude oil produced from these areas typically is exchanged or sold in midcontinent markets for which dependable index prices are published. MMS therefore believes it is appropriate that the index values from those markets be used in valuing production not sold at arm's length or for which the lessee opts to use index values under other provisions of the final rule, as explained below.

Suggested ''Operating Allowance'' Definition—Summary of Comments: We received a comment that ''operating allowance'' needs to be included in the definitions section. The commenter said it is still unclear what is meant by an operating allowance, both in this section and its predecessor section.

MMS Response: The operating allowance language was added to 30 CFR 206.106 in 1996 as part of a new rule on bidding systems for leases on the OCS. Operating allowances are to be predetermined and defined at the time of a lease sale. They may be used either to effectively replace the valuation regulations to calculate net receipts subject to the nominal royalty rate, or to reduce net receipts after the valuation regulations are applied to determine receipts subject to the nominal royalty rate. In either case, the approach used would be specified in the lease sale notice. Such allowances would be in lieu of any allowances that otherwise might have applied under the valuation rules. We chose not to define ''operating allowance'' so as not to confuse the application of allowances otherwise permitted under 30 CFR part 206 with the operating allowance concept. Any lessee with an operating allowance will be fully aware of its specifics regarding the applicable lease, because it will be defined explicitly in the notice of lease sale.

(b) Tracing Exchange Transactions (Proposed Paragraph 206.102(c)(3))

The February 1998 proposal expanded gross proceeds valuation to oil that is sold at arm's length after being involved in one or more arm's-length exchanges. This provision would have required the lessee to trace the oil through all such exchanges to assure they are all arm's length and to capture all location and quality differentials. If the lessee then sold at arm's length the oil it ultimately received, the value of the oil produced from the lease would have been the gross proceeds for the oil ultimately sold after the exchanges, adjusted for any location and quality differentials incurred in the course of the arm's-length exchanges.

Summary of Comments: Seventeen respondents (fourteen industry, two States, and one municipality) commented on the tracing aspect of the rule. They all agreed that tracing oil through multiple exchanges would be impractical, if not physically impossible, because of aggregation and commingling of Federal and non-Federal crudes of different qualities and the magnitude of administering a program to track individual exchange transactions. A few commenters asserted that the sharing of information about oil exchanges might violate United States antitrust laws.

One State commenter recommended confining gross proceeds valuation to an arm's-length first sale. Another commenter was concerned that Federal royalty oil could be valued at the lowest price received when there are multiple sales at the end of a series of exchanges.

As an alternative to tracing, one company suggested that the value of oil disposed of through arm's-length exchanges be based on the spot market price of the crude oil received, adjusted for location and quality differentials received or paid. An industry trade organization recommended replacing the tracing method with either: (1) Royalty valuation procedures (RVP's) based on arm's-length sales from nearby wells, or (2) a netback procedure. Some industry commenters were concerned that the proposed rule gave MMS too much latitude to disallow transactions under arm's-length exchange agreements, which would create uncertainty by allowing auditors to second-guess a company's marketing decisions.

MMS Response: The July 1997 proposal extended the use of gross proceeds valuation to oil exchanged and then sold at arm's length. In those cases where a lessee disposed of the produced oil under an exchange agreement with a non-affiliated person, and after the exchange the lessee sold at arm's length the oil acquired in the exchange, the lessee would have had the option of using either its gross proceeds under the arm's-length sale or the index pricing method to value the lease production (proposed paragraph 206.102(a)(6)(i)). This option would have applied only when there was a single exchange. If the lessee chose gross proceeds under this option, the lessee would have valued all oil production disposed of under all other arm's-length exchange agreements in the same manner (proposed paragraph 206.102(a)(6)(iii)). For any oil exchanged or transferred to affiliates, or subject to multiple exchanges, the lessee would have used the index pricing method to value the lease production (proposed paragraph 206.102(a)(6)(ii)).

Participants in MMS's workshops held in October 1997 indicated that they often use several exchanges to transport their production from offshore leases to market centers onshore. They believed that MMS should give the lessee an option of valuing exchanged oil either by using so-called "lease-market" benchmarks (rather than index prices) or by using the lessee's resale price less an exchange differential, regardless of the number of exchanges needed to reposition the crude oil for sale.

In response to those comments, in the February 1998 proposal MMS expanded gross proceeds valuation to include situations where the oil received in exchange is ultimately sold arm's length, regardless of the number of arm's-length exchanges involved. However, because many industry comments claimed that tracing multiple exchanges would be overly burdensome, while others wanted the ability to use the ultimate arm's-length gross proceeds, in the final rule, MMS is providing an option to use either the arm's-length gross proceeds following one or more arm's-length exchanges, or the provisions of § 206.103. The chosen option will apply for at least 2 years, and the lessee must use this method to value all of its crude oil produced from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that the lessee or its affiliate sells at arm's length following one or more exchanges. The provisions of § 206.103 will apply for oil that is not sold at arm's length after the exchange, as well as to oil subject to non-arm's-length exchanges. We included these qualifications to assure that lessees will not abuse the system by choosing case-specific options or time periods that best suit their situations, or by using non-arm's-length exchange differentials to determine royalty value.

As discussed elsewhere in this preamble, the final rule does not use the industry's suggested "RVP's." In the RMR, however, the final rule uses a prescribed series of benchmarks similar to the suggested "RVP's," for reasons explained elsewhere in this preamble. Also, as discussed elsewhere in the preamble, MMS believes that except for the RMR, spot prices are the best indicators of value.

The lessee's duty to market does not mean that MMS will second-guess a company's marketing decisions. Lessees may structure their business arrangements however they wish, and, absent misconduct or breach of the lessee's duty to market to the benefit of itself and the lessor, MMS will look to the ultimate arm's-length disposition in the open market as the best measure of value.

(c) Different Geographic Regions (Proposed § 206.103)

Based on the isolation of the West Coast petroleum market and its distinctive market conditions, the previous rulemaking proposals recognized two geographic regions for valuation: (1) California and Alaska and (2) the remainder of the country. However, from the comments received on these proposals, it became apparent that oil marketing in the RMR is significantly different. Accordingly, the February 1998 proposal recognized three regions for royalty valuation: (1) California and Alaska, (2) the RMR, and (3) the rest of the country.

Summary of Comments: Four respondents representing industry commented on the three-region approach; all opposed it. They claimed that the geographically different valuation standards will require companies to install additional computer systems or systems software and hire corresponding additional staff. One respondent recommended revising the existing non-arm's-length valuation benchmarks to provide universal valuation procedures that would determine value at the lease.

State participants at MMS's October 1997 workshops supported different valuation methods for different regions of the country.

MMS Response: There was general consensus among commenters that the RMR exhibited particular oil marketing characteristics that would justify different royalty valuation standards. Production is controlled by relatively few companies in the RMR; the number of buyers is also more limited than in the Gulf Coast and midcontinent regions; and there are limited third-party shippers, resulting in less competition for transportation services in this region. There is less spot market activity and trading in this region as a result of the control over production and refining. Finally, crude oil production in the RMR typically involves much smaller volumes and is more scattered than in the Gulf Coast and midcontinent regions.

Beginning with the January 1997 proposal, MMS has maintained a separate valuation methodology for production in California and Alaska. As explained thoroughly in previous proposals, the California and Alaska markets are unique and warrant different valuation methods. The final rule maintains this difference and thus establishes three regions including (1) California and Alaska, (2) the RMR, and (3) the rest of the country.

Industry stated that new computer systems are needed, with the possibility of three separate systems for the three regions of the country with separate valuation requirements. However, they did not provide any rationale as to why, or any specifics on how those computer systems would be different than what they need under the current regulations. The majority of payors will continue to pay on the gross proceeds received under an arm's-length sale just as they always have. This means that they will not incur any additional computer costs or time in complying with the arm's-length provisions of the new rule. For those not paying on gross proceeds, industry has not shown that the methods applicable to the three different regions of the country will require unduly complicated or costly computer systems overhaul or substantial additional staff. We recognize, however, that the changes in valuation methodology will require some systems changes. For that reason the final rule includes a ''grace period'' for royalty adjustments necessitated by system changes. The grace period includes the first three production months following the effective date of the rule. There will be no liability for late payment interest during this period. The final rule includes three geographic regions as contained in the February 1998 proposal.

(d) Restrictions on Rocky Mountain Region Benchmarks (Proposed Paragraph 206.103(b))

Under the February 1998 proposal, the value of crude oil produced in the RMR and not sold at arm's length would be determined by the first applicable of the following benchmarks:

(1) For lessees with an MMS-approved tendering program, value of production from leases in the area covered by the tendering program would be the highest price bid for the tendered volumes. To exercise this benchmark, the lessee would have to offer and sell at least 33⅓ percent of its total Federal and non-Federal production from that area under the tendering program and would have to receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

(2) A value calculated as the volume-weighted average of the gross proceeds accruing to the lessee or its affiliate for arm's-length purchases or sales of production from the field or area during the month. The total volume purchased or sold under the arm's-length transactions must exceed 50 percent of the lessee's or its affiliate's Federal and non-Federal production from the same field or area during that month.

(3) A value calculated as the average of the daily mean spot prices published in any MMS-approved publication for WTI crude at Cushing, Oklahoma, for deliveries during the production month, adjusted for location and quality differentials.

(4) If the lessee demonstrates to MMS's satisfaction that the first three benchmarks result in an unreasonable value for its production, the MMS Director may establish an alternative valuation method.

Summary of Comments—Tendering: Six respondents, all representing industry, commented on benchmark 1 (tendering). They all opposed the restrictions, claiming they were excessive and would all but eliminate tendering as a measure of value. Comments included:

- The method MMS used to arrive at the one-third volume requirement is flawed because if the lease is Federal, there is no State royalty or tax interest involved. Likewise, if the lease is a State lease, there is no Federal interest involved. Requiring one-third of the lessee's total production is onerous as a practical matter; a more reasonable volume would be 15 or 20 percent.
- Lessees have no control over the number of bids received. Together with the limited number of producers in the Rocky Mountain Area, the three-bid restriction would negate tendering as a viable benchmark in many cases.
- The use of the highest bid is unreasonable unless all the bids happen to be for the full tendered volume.
- If the lessee has a refining affiliate, that affiliate would be disqualified from bidding on oil tendered by others, while at the same time being excluded from buying at least one-third of its affiliated lessee's own production.

A few commenters thought that tendering, without the restrictions, would offer a viable valuation tool, not only for the RMR but nationwide.

MMS Response: MMS added the several qualifications stated above to ensure receipt of market value under tendering programs. First, royalty value must be the highest price winning bid rather than some other individual or average value. We believe this is necessary to assure receipt of market value.

Second, MMS acknowledges that the minimum tendered volume could be less than 33 ⅓ percent, but only by a small amount. In the final rule, you must offer and sell at least 30 percent of your production from both Federal and non-Federal leases in that area. MMS wants to ensure that the portion put up for tendering at least covers the Federal royalty interest and the composite State effective tax rate on oil production. That combination typically ranges from about 17 percent to about 27 percent. These percentages do not include State royalty rates, which did not enter into the calculation. The rationale for this minimum percentage is to ensure that the lessee puts a sufficient volume of its own production share up for bid to minimize the possibility that it could ''game'' the system for Federal royalty or State tax payment purposes. In this final rule, we thus chose 30 percent as the minimum percentage the lessee would have to tender for sale to assure that some of the lessee's equity share of production generally was involved. Likewise, the tendering program must include non-Federal lease production volumes in the 30 percent determination to ensure that the program isn't aimed at limiting Federal royalty value.

In our February 1998 proposal, we stipulated a minimum of three bids. However, we received several comments that requiring three bidders was too stringent and that in many cases there simply would not be that many qualified bidders. We have reviewed this criterion and continue to believe that a minimum number of bidders is essential to ensure receipt of market value. We believe that at least three bidders are needed to provide an adequate measure of market value and have retained this provision in the final rule. Further, MMS is concerned about the possibility of companies cross-bidding at below-market prices. That is why in the final rule we have retained the stipulation that the minimum of three bids must come from bidders who do not also have their own tendering programs in the area.

Summary of Comments—Weighted Average Gross Proceeds: Five respondents, four industry and one State, commented on benchmark two (weighted-average gross proceeds). Comments included:

- The 50-percent arm's-length-sales threshold is too high. There is no reasonable justification for this percentage. Twenty to 25 percent is a sufficient statistical percentage to establish value.
- Where oils of different qualities are produced in the same field or area, the weighted-average method could lead to undervaluing of high-quality oils. Lessees can game the system by buying low-quality crudes and reporting their weighted-average value for high-quality crudes.
- Any discounting of prices for certain volumes would lead to inaccurate weighted averages.
- MMS received several industry comments that the proposed rule would cause hardships for producers who have marketing, but not refining, affiliates. The marketing affiliate takes the producing affiliate's production and also buys production from various other sources before reselling or otherwise disposing of the combined volumes. Section 206.102 requires the producer to base royalty value on its marketing affiliate's various arm's-length sales and allocate the proper values back to the Federal lease production. The commenters said this ''tracing'' would be difficult at best. One commenter suggested that as an alternative the lessee should be permitted to base the value of its production on the prices its marketing affiliate pays for crude oil it buys at arm's length in the same field or area.

MMS Response: MMS developed this method as the next alternative if a qualified tendering program does not exist. (One of the Rocky Mountain State commenters recommended that the alternatives be given in this order). This method is an effort to establish value based on actual transactions by the lessee and its affiliate(s). Just as for the tendering program, MMS believes a floor percentage of the lessee's and its affiliates' production should be set to prevent any ''gaming.'' Although we received several comments that the 50 percent minimum figure is too high, it is not intended to be a more stringent standard than the 30 percent floor associated with the tendering program. That is because the 50 percent floor applies to the lessee's and its affiliates' sales *and* purchases in the field or area, rather than just sales. (The tendering program involves only sales.)

We also received a comment expressing concern that lessees would have to perform additional work each month to determine whether they met the 50 percent threshold. In response to this concern, the final rule permits the option that if the first benchmark does not apply, the lessee may apply either the second or third benchmarks. Thus, if the lessee believes the continuing work involved in determining whether they meet the 50 percent threshold is too great, they may apply the third benchmark (spot prices at Cushing, Oklahoma, adjusted for transportation and quality differences).

This final rule requires using a gravity-adjusted volume-weighted average gross proceeds accruing to the seller in all of the lessee's and its affiliates' arm's-length sales or purchases, not just those that may be considered comparable by quality or volume. We received several comments that the method in the February 1998 proposal would result in improper valuation of some oil that was significantly different in quality than that associated with the ''average'' oil. In general, we believe that production in the same field or area will be similar in quality. However, in response to comments, in the final rule we require that before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliate's arm's-length purchases or sales to the same gravity as that of the oil produced from the lease. Further, given that these sales and purchases must be greater than 50 percent of all of the lessee's production in the field or area, we believe that it is not necessary to distinguish comparable-volume contracts.

We cannot agree with the comment that oil resold by a marketing affiliate of the producer should be valued using this benchmark. An overriding general premise of this rulemaking is that where oil ultimately is sold at arm's length before refining, it should be valued based on the gross proceeds accruing to the seller under the arm's-length sale. To do otherwise would be inconsistent with the way arm's-length resales are treated elsewhere in this rule. However, this final rule offers the option that where the production is sold or transferred to an affiliate who then resells it, the lessee could value its production using § 206.103 rather than the affiliate resale price. This does not mean that MMS believes the affiliate's arm's-length resale price should not form the valuation basis; rather, we are accommodating those who say ''tracing'' production is a problem by offering an alternative that should ease their administrative burden while still providing a fair royalty value. MMS is willing to permit this option because it anticipates that overall the index prices used under § 206.103 will approximately reflect what affiliated marketing entities are able to obtain under most circumstances.

Summary of Comments—NYMEX Futures Prices: Nine respondents, all representing industry, commented on benchmark three, NYMEX futures prices. Consistent with industry's previous position on NYMEX prices (*i.e.*, the futures market bears little relation to lease markets; see Sections III and IV), they all opposed NYMEX pricing as a measure of value for the RMR. One commenter pointed out the difficulty of applying NYMEX sweet prices to Wyoming sour crude.

MMS Response: As discussed in Section III(g) of this preamble, the final rule does not use NYMEX futures prices as a measure of value. Instead, MMS chose to use spot prices because studies indicated that when NYMEX prices, properly adjusted for location and quality differences, are compared to spot prices, they nearly duplicate those spot prices. Further, except for the RMR, application of spot prices removes one portion of the adjustments to the NYMEX price that would have been needed—the leg between Cushing, Oklahoma, and the market center location.

(e) Spot Prices (Proposed Paragraph 206.103(c))

Under the February 1998 proposal, the value of crude oil produced outside California, Alaska, and the RMR and not sold at arm's length was the average of the daily mean spot prices for deliveries during the production month:

—For the market center nearest the lease where spot prices are published in an MMS-approved publication and
—For the crude oil most similar in quality to the lease crude.

The average spot prices would be adjusted for location and quality differentials and for transportation costs to derive the royalty value.

Summary of Comments: Thirteen respondents—twelve industry and one State—commented on spot prices as a measure of value. One industry respondent supported the change from NYMEX-based pricing to spot prices, stating that the change bases valuation on a crude oil more similar in quality and at a location closer to the lease while eliminating an adjustment step in the valuation process that is prone to error.

The remaining eleven industry respondents opposed the use of spot prices (along with any other index pricing method) to value crude oil production. Their arguments included:

- Spot prices do not accurately reflect lease values. Spot prices represent the cost of obtaining crude oil for delivery within 30 days. By contrast, a great deal of market activity is accounted for by longer-term arrangements.
- Spot prices do not move in lock-step with local markets; they do not reflect the influence of local supply and demand.
- Spot prices capture downstream value enhancements; differential adjustments are inadequate to compensate for the value added by moving the production from the lease to a market center.
- Spot prices published by commercial news services are based on limited polling of traders; there is no uniform calculation method and accuracy is dependent on the reporter's judgment.

The State commenter disagreed with abandoning NYMEX prices for spot prices. This commenter contended that NYMEX prices better reflect market value because NYMEX transactions constitute a much larger volume of trades than spot markets and because the NYMEX market is less subject to manipulation than spot markets.

MMS Response: The body of evidence regarding actual marketing practices indicates that index prices, including spot prices, play a significant role in setting contract prices. The final rule maintains the use of ANS spot prices in California for oil not sold at arm's length. Location- and quality-adjusted spot prices, rather than NYMEX futures prices, also are used for oil not sold at arm's length for oil produced elsewhere. (For the RMR, spot prices at Cushing, Oklahoma, are used as the third benchmark.) We believe that the location and quality adjustments together with the transportation allowances specified in the final rule effectively result in market value at the lease. Similarly, even though spot prices are not established directly for all local markets, we believe that the location and quality adjustments do result in reasonable measures of value in the local markets.

However, we believe that in some cases the use of spot prices determined before the production month, as proposed in February 1998, could affect lessees' production decisions and, ultimately, royalties paid. Therefore, in the final rule, we have adopted the procedure for applying spot prices proposed in January 1997, rather than the procedure proposed in February 1998, for the following reasons.

Assume the average daily spot price in an MMS-approved publication is determined April 26–May 25 for the delivery month of June. Further assume that the lessee transfers its production to an affiliated marketing entity who then resells at arm's length and that the lessee has opted to value the production at the index price. The lessee responsible for reporting June production volumes and values would then know the June spot price (and therefore the royalty value) by the end of May, before its production for the month of June even begins. If the daily spot price then rose through the rest of May and the early part of June, the lessee might decide to increase production over at least a short period and thereby realize more per barrel than the royalty value. Conversely, if the daily spot price fell after May 25 and into early June, the lessee might decide to decrease production so as to be impacted minimally by realizing less per barrel than the index price it must use for royalty payments. To prevent such potential problems, the final rule applies the spot price effectively determined during the production month so that the price determination is concurrent with production. So, for example, for May production in the Gulf of Mexico you would use the spot price determined from April 26 through May 25 for June delivery.

Several commenters said that use of a spot price improperly captures downstream value enhancements and that the differentials specified by MMS are inadequate. We covered this issue thoroughly in Section III(i) earlier in this preamble. We point out again here that MMS has never allowed deductions from royalty value for marketing costs. This rulemaking makes no change to the lessee's duty to market. Valuation based on a ''downstream'' sale or disposition of production has been commonplace for many years, because the initial basis for establishing value often is a ''downstream'' sales price. The United States as lessor always has shared in the ''benefit'' of ''downstream'' marketing away from the lease, and has allowed deductions for the cost of transportation accordingly.

One of the real issues between industry and MMS is what costs should be allowed as part of the transportation function. The industry would like more costs included as part of transportation than MMS is willing to allow. MMS has prescribed by rule what transportation costs are deductible, and believes that the allowed costs are proper.

Finally, MMS believes the available spot prices represent accurate assessments of day-to-day oil market value. MMS has reviewed the procedures used by the major price reporting services. While it is true that spot prices result from surveys done by individuals, we believe their procedures and safeguards produce meaningful value assessments. Further, comparisons of spot prices with NYMEX futures prices show a direct correlation between the two when appropriate location and quality adjustments are made. We did find some spot price locations—for example, Guernsey, Wyoming, and Kern River and Line 63 in California—where the volumes traded were so limited that we didn't believe we should rely on the resulting spot price. We did not use those spot prices in the final rule.

(f) Nonbinding Valuation Guidance (Proposed § 206.107)

This section of the February 1998 proposal provided that lessees may ask MMS for valuation guidance or propose a valuation method to MMS. It stated that MMS will promptly review the proposal and provide the requestor with a nonbinding determination.

Summary of Comments: Three industry commenters were concerned with the nonbinding nature of the guidance. As stated by one of the commenters:

- MMS offers no explanation for abandoning the current regulations, which don't specify that value determinations are nonbinding.
- As a practical matter, a lessee would not seek a nonbinding value determination.
- If the guidance is favorable to the lessee, MMS would not be bound by it. (In other words, MMS could change its mind at a future date.)
- If the guidance is unfavorable to the lessee, it might be at risk for civil penalties for willfully and knowingly not complying if it disregards the guidance; yet the lessee has no recourse to appeal the guidance.

MMS Response: In the final rule, in response to comments, we are providing a procedure for valuation determinations that is more than simply non-binding guidance. Under § 206.107 of the final rule, you may request a value determination from MMS regarding any Federal lease oil production. (Your request must identify all leases involved, the record title or operating rights owners, and the designees for those leases, and explain all relevant facts.) MMS may either:

(1) Issue a value determination signed by the Assistant Secretary, Land and Minerals Management; or

(2) Issue a value determination by MMS; or

(3) Decline to provide a value determination.

A value determination signed by the Assistant Secretary, Land and Minerals Management, is binding on both you and MMS until the Assistant Secretary modifies or rescinds it. It is also the final action of the Department and is subject to judicial review under the Administrative Procedure Act, 5 U.S.C. 701–706.

In contrast, a value determination issued by MMS is binding on MMS and delegated States with respect to the specific situation addressed in the determination, unless the MMS or the Assistant Secretary modifies or rescinds it. In the December 1999 proposal, we used the term ''MMS Director'' instead of ''MMS''. We changed the reference to ''MMS'' so that it was clear that the Director could delegate this authority, for example, to the Associate Director for Royalty Management.

Further discussion of States' concerns on their input to value determinations is provided at Section IX (u) of this preamble.

A value determination by MMS is not an appealable decision or order under 30 CFR part 290 subpart B. If you receive an order requiring you to pay royalty on the same basis as the value determination, you may appeal that order under 30 CFR part 290 subpart B.

A few commenters at the January 2000 public workshops asked MMS to specify that if a lessee chooses not to follow a value determination by MMS, it will not be subject to civil penalties under FOGRMA section 109(c), 30 U.S.C. 1719(c), for knowing or willful underpayment of royalties. A decision not to follow an MMS value determination will not, in and of itself, result in a civil penalty assessment for knowing or willful underpayment. However, it does not immunize the lessee from penalties for knowing or willful violations if the lessee's conduct constitutes a knowing or willful underpayment independent of the MMS value determination.

Importantly, a change in an applicable statute or regulation on which any value determination is based takes precedence over the value determination. It is not necessary for the MMS or the Assistant Secretary to modify or rescind the value determination for the new statute or rule to take precedence.

With certain exceptions, a value determination may be modified only prospectively. However, the MMS or the Assistant Secretary may modify or rescind a value determination retroactively if there was a misstatement or omission of material facts in your request, or if the facts subsequently developed are materially different from the facts on which the guidance was based. In situations such as these, the agency should not be bound by a value determination.

Situations in which MMS typically will not provide any value determination include, but are not limited to, requests for guidance on hypothetical situations and matters that are the subject of pending litigation or administrative appeals. MMS also typically will not use a value determination to resolve factual disputes either between MMS and the lessee, or between the lessee and third parties (for example, a purchaser) where those disputes are relevant to royalty value. While MMS will respond to requests for value determinations, it is not obligated to issue a value determination.

Value determinations are issued only under § 206.107, in response to a specific request for a value determination. Under other provisions of the rule, lessees may ask MMS to make certain other determinations—for example, to establish a location/quality adjustment under § 206.112, or even (as the fourth benchmark for non-arm's-length dispositions in the RMR under § 206.103(b)) to establish a valuation method.

(g) Adjustments and Transportation Allowances (Proposed §§ 206.109 through 206.112)

Summary of Comments: Twenty respondents, including sixteen representing industry, three representing States, and one representing a municipality, commented on various aspects of location and quality adjustments and transportation allowances. Industry continued to oppose: (1) Differentials that do not allow all post-production marketing costs and services; (2) the elimination of the exception permitting requests to use FERC tariffs instead of actual costs for determining transportation allowances; and (3) limits on transportation allowances. Several industry commenters believed the proposed rules discriminate against lessees with affiliated transporters by requiring them to use a regulatory cost calculation to determine their transportation allowances, whereas third parties are permitted to use tariffs.

MMS Response: In Section III(*i*) of this preamble, we responded in detail to comments about not allowing marketing costs.

In the final rule, we have eliminated the option for lessees to request the use of a FERC tariff in lieu of calculating its actual transportation costs in non-arm's-length transportation arrangements. Since the 1988 rules were promulgated, FERC has renounced jurisdiction over many, if not most, pipelines on the OCS. Oxy Pipeline, Inc., 61 FERC ¶ 61,051 (1992); Bonito Pipeline Co., 61 FERC ¶ 61,050 (1992), aff'd sub nom., *Shell Oil Co.* v. *FERC,* 46 F.3d 1186 (D.C. Cir. 1995); *Ultramar, Inc.* v. *Gaviota Terminal Co.,* 80 FERC ¶ 61,021 (1997). Those FERC decisions resulted in MMS rejecting use of FERC tariffs under the existing rule because FERC cannot ''approve'' a tariff over which it has no jurisdiction. This in turn has resulted in litigation between several lessees and the Department over the applicability and meaning of the existing rule. *Shell Offshore, Inc.* v. *Babbitt,* No. CV98–0853 (W.D. La. Mar. 17, 1999), appeal pending, Nos. 99–30532 and 99–30745 (5th Cir.); *Torch Operating Co. et al.* v. *Babbitt,* Nos. 1:98CV00884 ES and consolidated cases (D.D.C.).

Absent any possibility of review or check by FERC over the reasonableness of the rates filed with FERC for such pipelines, MMS has no avenue to assure that the ''tariff'' filed by a pipeline affiliated with the lessee is reasonable. The potential for lessees to claim excessive transportation allowances in non-arm's-length situations is clear. Indeed, in many cases, MMS auditors have found that the FERC tariff the lessee has used is considerably higher than the actual costs that otherwise would be allowed under the existing rule.

This contrasts with the situation where a lessee pays an unaffiliated pipeline the rate that the pipeline had filed with FERC. In that event, the ''tariff'' represents the lessee's actual transportation costs because that was what it in fact was charged. Thus, in eliminating the FERC tariff exception, lessees are allowed to deduct their actual costs in both cases.

Further, in this final rule MMS has retained the provision that if the lessee's actual transportation costs exceed 50 percent of the value of the product, the lessee may apply for, and MMS may approve, an allowance greater than that amount.

Summary of Comment—Duplicate Quality Adjustments: One State commenter believed that proposed paragraph 206.113(a) permitted ''double-dipping'' for quality adjustments, since paragraphs 206.112(a) and (e) both provide for quality adjustments, thus allowing a double deduction for quality for crude oil at the lease and the market center. This commenter also noted that because paragraph 206.112(a) allows for deduction of a location differential between the lease and the market center, and paragraph 206.112(c) allows for deduction of transportation costs between the lease and the aggregation point, paragraph 206.113(a) will allow the lessee to deduct its transportation costs from the lease to the aggregation point twice.

MMS Response: In this final rule, we added a new paragraph (g) to § 206.112 to clarify that you may not use any transportation or quality adjustment that duplicates all or part of any other adjustment that you use under § 206.112. Moreover, the structure of the final rule is not susceptible to the problem the commenter describes. Under the final rule, for example, if you dispose of your production under an arm's-length exchange agreement, but transport the oil away from the lease to an intermediate point before giving it in exchange, you cannot claim a transportation allowance between the point where you give the oil in exchange and the point you receive oil back in exchange if you use a location differential for the segment between those two points. This same principle applies for all adjustments addressed in § 206.112. That is, any time a lessee takes one of the listed adjustments, it cannot duplicate any portion of that adjustment as part or all of any other adjustment that otherwise would be allowable.

Summary of Comment—No Quality Adjustment in Absence of Quality Bank: One commenter noted that, in the absence of a quality bank, the rule does not provide for any adjustments for quality differences between the indexed crude oil and the oil produced at the lease.

MMS Response: In the final rule, MMS intentionally did not include a specific quality differential unless there is a quality bank that applies to the lessee's production. MMS does not want to be in a position of permitting quality adjustments where they may not be warranted. Further, quality adjustments will be reflected in the location differentials applied by lessees from their arm's-length exchange agreements. Finally, MMS has provided, in § 206.112 of the final rule, that if the lessee believes it does not have the information necessary to calculate a location/quality differential or transportation allowance, the lessee may request approval from MMS for the location/quality differential or transportation allowance. This may provide an opportunity to reflect quality differences the lessee believes are not otherwise accounted for.

VII. Responses to Public Comments on July 1998 Proposal

MMS's July 1998 proposal included several additional proposed changes based on comments received on the February 1998 proposal:

(1) The definition of ''affiliate'' was changed back to its meaning under the current rule, but made separate from the ''arm's-length'' definition;

(2) Specific regulatory language was inserted stating that MMS would not ''second guess'' lessees' marketing decisions by disallowing arm's-length gross proceeds as royalty value; and

(3) The procedure for valuing production subject to arm's-length sale following exchanges was modified. Value would be the arm's-length sale price following a single exchange, but where more than one exchange is involved, the lessee would have to use index pricing.

MMS also requested comments on the definition of ''gathering'' as related to deepwater leases involving subsea production without a platform but with long-distance movement of bulk production.

We received approximately 200 pages of comments within 25 separate submissions. Commenters included 3 States (6 submissions), 4 industry trade groups, 12 producers (13 submissions), 1 watchdog group, 1 concerned citizen, and two members of Congress (1 submission).

Although MMS asked for specific comments relating to particular issues (63 FR 38355), and reiterated that previous comments need not be resubmitted because they are already part of the record, there were many comments similar to previous submissions. Rather than repeating all such issues and comments here, we refer the reader to Sections I, III, IV, V, and VI. Instead, with a few exceptions, we address only those comments on provisions that are new or revised from the previous proposals. The comments fall into 11 topical categories ((a) through (k) below). Each topic begins with a description of the issue and is followed by a summary of comments and MMS's response.

(a) General Comment

The issue relates to the overall changes in MMS's July 1998 proposal.

Summary of Comments: One commenter believes the latest proposal provides numerous concessions to industry and thus amounts to a weaker rule.

MMS Response: We disagree with this comment. None of the changes in the July proposal should result in a weaker rule. Rather, they clarify the specifics of the rule and make it more usable for all involved. The changes result from a reasoned analysis of comments made by all parties over this extended rulemaking process. Rather than trying to give a specific response to this general comment, we address the proposed changes in the July 1988 proposal one-by-one below.

(b) MMS's Proposed Definition of Affiliate

MMS proposed retaining the meaning of ''affiliate'' embodied in the current rules at § 206.101, but removing it from the ''arm's length'' definition.

Summary of Comments: One commenter believed that the 10 percent threshold which constitutes no controlling interest in an affiliate is too low; at least 20 percent should be used, because this is the standard used by the Bureau of Land Management. Most commenters believed that the definition of affiliate was too vague, and specific criteria for rebutting the presumption of control were needed. One commenter believed the burden should be on the lessee to prove that the presumption of control is incorrect. One commenter stated that transactions between affiliates with any common ownership should not be considered arm's length. One commenter believed that by retaining the current definition of affiliate, it becomes easier for a company to pay on gross proceeds rather than index, which is the proper value.

MMS Response: See MMS's response in Section VI(a).

Summary of Comments: One group presented a scenario in which a small group of producers bands together to build a pipeline, but if one member of the group owns more than a 10 percent interest in the pipeline, they may be penalized under the affiliate definition.

MMS Response: This scenario is unlikely to play out as portrayed. Moreover, the definition of ''arm's length'' goes beyond ownership and affiliation. The owners also must have opposing economic interests in the pipeline to claim arm's-length status. Under this common ownership scenario all the owners likely would be deemed non-arm's-length as related to the pipeline.

(c) Breach of Duty To Market

In the July 1998 proposal, MMS tried to allay industry concerns about potential additional royalty assessments by adding specific language to § 206.102(c)(2)(ii) that MMS would not use the ''breach of duty'' provision to second-guess industry marketing decisions.

Summary of Comments: Industry and their representative organizations were not reassured that MMS will not ''second-guess'' their marketing decisions. Many believed the terms ''substantially below'' and ''market value'' were not easily defined and could lead to MMS questioning legitimate transactions. One commenter said that MMS has in the past rejected legitimate, at-the-lease prices in favor of higher, downstream prices. One commenter believed that as long as a company is acting in good faith, they have nothing to fear with MMS ''second-guessing'' their decisions. One commenter offered alternate ''breach of duty to market'' language.

MMS Response: The provision MMS was attempting to clarify with its proposed additional language is identical to the provision in the existing rules (see 30 CFR 206.102(b)(1)(iii)). It has resided in those rules for over a decade and has not been used to second-guess a lessee's marketing decisions to try to impose the benchmarks at § 206.102(c) on arm's-length transactions.

We agree with the commenter who said lessees have nothing to fear if they are acting in good faith. This provision is simply meant to protect royalty value if, for example, a lessee were to inappropriately enter into a substantially below-market-value transaction for the purpose of reducing royalty.

In § 206.102(c)(2)(ii) of the final rule, in response to comments, we specifically state that MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract. The fact that the price received by the seller in an arm's length transaction is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil from the lease. Likewise, the fact that one co-lessee sells production at the lease while another lessee sells its production downstream does not imply that the co-lessee who sells at the lease has breached its duty to market.

Some commenters have argued that adding to the lessee's gross proceeds the marketing costs that a purchaser of oil, rather than the lessee, incurred constitutes ''second guessing'' of an arm's-length contract. They cite as a purported example of such ''second guessing'' the IBLA's decision in Amerac Energy Corp., 148 IBLA 82 (1999) (motion for reconsideration pending). MMS strongly disagrees with this argument. The Amerac case is not an example of ''second-guessing.'' Lessees may not avoid the obligation to market production at no cost to the lessor by transferring the function to the purchaser and accepting a lower price in return. In the Amerac case, neither MMS nor the IBLA ''second guessed'' the contract at all.

(d) Marketing Fees

MMS has maintained its ''duty to market'' provision with no additional deductions allowed for marketing or other associated costs.

Summary of Comments: One commenter believes the administrative fee that is charged under MMS's existing Small Refiner Royalty-In-Kind program is analogous to a marketing fee. Consequently, lessees who use index prices should be allowed to deduct marketing fees from these prices.

MMS Response: The fee charged to the small refiners for participation in the RIK program covers MMS's additional costs in administering the program and does not relate to a marketing fee. The MMS fee does not parallel marketing costs incurred by the producers.

(e) Exchanges

In response to earlier industry comments, MMS proposed in its July 1998 proposal that where oil was involved in a single exchange before an arm's-length sale, its value should be based on the arm's-length gross proceeds under that sale. But if there were two or more exchanges, the oil would be valued under § 206.103.

Summary of Comments: Most industry commenters and their representative groups still stressed the problem of tracing the oil through an exchange to determine proper value. In many cases, the oil is commingled with non-Federal oil and sold in bulk, creating difficulty in determining the true value of the Federal portion. Additionally, there can be a significant workload if any corrections need to be made to previously-reported values. The producer should at least be given the option of using: (1) the arm's-length sales price after the exchange, or (2) index value. One commenter believed that any exchange between affiliates should not be considered arm's length, that the definition of exchange should be modified to include only exchanges that are truly at arm's length, and that the definition of exchange should be expanded to include other specific types of exchange agreements. Two commenters believe that if a lessee is to use gross proceeds after an exchange, then it must report all balancing agreements for that lease to the MMS.

MMS Response: MMS understands the potential administrative burden of tracing. We are also well aware of the desire of other producers, as expressed in the meetings sponsored by Senator Breaux on July 9 and July 22, 1998, to be able to use prices received in arm's-length sales following multiple exchanges. As a result, in this final rule, MMS allows lessees the option of using either their arm's-length gross proceeds regardless of the number of arm's-length exchanges preceding the arm's-length sale, or the provisions of § 206.103 (index prices or, in the RMR, benchmarks). The selected option, once chosen, cannot be changed for 2 years and must be applied to all of the lessee's oil produced from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that is sold at arm's length following one or more exchanges. This process preserves the integrity of the rule's underlying principle of applying arm's-length gross proceeds where appropriate, but still allowing use of index/benchmark values that fairly represent market value where ''tracing'' would be too burdensome.

Also, we acknowledge that exchanges between affiliates are not at arm's length. Because there is potential for inflated differentials in such exchanges, production so transferred and followed by an arm's-length sale must be valued at the appropriate index/benchmark value under this final rule. We also agree that the definition could be clarified by specifying several other types of exchange agreements. We have done this in the final rule. We do not believe, however, that it is to the lessee's or MMS's benefit for all balancing agreements to be reported to MMS. Such agreements should be made available on audit or as otherwise requested by MMS.

(f) Binding Guidance

MMS did not request comment on this issue in its July 1998 proposal, but drew several comments. The February 1998 proposal stated that lessees could petition MMS for non-binding guidance.

Summary of Comments: MMS received five comments stressing the importance of MMS issuing binding guidance. They believed that the nature of a business relationship requires it. One commenter believed that guidance should not be binding because all of the facts may not be available at the time the guidance is issued.

MMS Response: See Section VI(f) of this preamble for a complete discussion of this issue.

(g) Gathering versus Transportation

MMS asked for comment on whether the definition of transportation should include subsea movement of bulk, untreated production over distances of 50 miles or more. This typically involves a subsea completion and subsequent movement to a platform where the production first surfaces and is treated. If this movement is considered transportation, the associated costs may be allowable deductions from royalty. If the movement is considered gathering, the costs would not be allowed.

Summary of Comments: MMS received mixed comments on this issue. The majority of the producers commented that movement away from the lease should be considered transportation. Other comments centered on the fact that many deepwater leases are already receiving some type of royalty relief, and additional deductions are not warranted.

MMS Response: This issue arose in the public comments for the first time in the meetings of July 9 and 22, 1998, sponsored by Senator Breaux. In the past, MMS has consistently held that movement of production to a central accumulation or treatment point prior to the royalty measurement point is considered gathering, rather than transportation of marketable production eligible for a deduction from royalty. In this final rule, MMS has not changed the existing regulatory language. (However, we further note that on May 20, 1999, the MMS Associate Director for Royalty Management issued guidance regarding movement of production from deepwater leases).

(h) MMS Use of BBB Bond Rate

The existing rule uses the Standard and Poor's Industrial BBB bond rate as an allowable rate of return on capital investment for producers who transport oil through their own pipelines (see 30 CFR 206.157(b)(2)(v)).

Summary of Comments: Two commenters from affiliated companies said the use of the BBB bond rate as an allowable return within the calculation of actual costs of transportation is arbitrary and would be considered unacceptable by any court. The actual rate should be much higher, reflecting the real rates of return seen in the Gulf of Mexico, and particularly in deep waters to recognize additional risk.

MMS Response: We have continued the use of the Standard and Poor's BBB industrial bond rate in this final rule. MMS did not propose specific provisions regarding the rate of return, but received numerous comments on those issues. This issue is discussed more fully below in the responses to the comments on the December 1999 proposal in paragraph IX(a).

(i) Quality and Transportation Adjustments

In its February 1998 proposal, MMS allowed quality adjustments in § 206.112 based on premia or penalties determined by pipeline quality bank specifications at intermediate commingling points, at the aggregation point, or at the market center applicable to the lease. Allowable transportation deductions were based on actual costs of movement, consistent with the rules currently in effect.

Summary of Comments: Two commenters believe that only gravity and sulfur banks should be used for quality adjustments. One commenter believes the rule should allow transportation costs only to the nearest market center and by the cheapest means to move it there.

MMS Response: In this final rule, MMS intentionally did not include specific quality differentials unless a quality bank applies to the lessee's production. MMS does not want to permit quality adjustments where they may not be warranted. Further, quality adjustments will be reflected in the location differentials applied by lessees from their arm's-length exchange agreements and in location differentials that MMS provides to lessees upon request under § 206.112(f). In this way, MMS is allowing only additional pipeline-specific adjustments where they exist.

Consistent with the current rules, transportation allowances in this final rule are based on actual transportation costs. MMS historically has not questioned whether the transportation was to the nearest market center or whether it was by the cheapest means available. We presume that lessees will act prudently to market their oil at the appropriate point and use the most efficient means of transportation available. Once again, MMS does not intend to ''second-guess'' marketing decisions to which these factors apply.

(j) Tendering and Other Alternatives

In its various proposals, MMS generally has not incorporated industry-proposed valuation alternatives. An exception is application of tendering programs in the RMR.

Summary of Comments: Many comments from industry and their trade groups criticized MMS for not permitting use of viable alternatives such as tendering programs in all parts of the U.S. Additionally, MMS ignored many lease-based alternatives and the option of taking royalty in kind.

MMS Response: MMS believes it has adequately responded to all alternatives presented by industry above. For example, see Section VI(d) for detailed comments and responses regarding tendering programs and Section III(r) for a discussion of royalty in kind.

(k) Gross Proceeds Valuation

The various MMS proposals have allowed lessees to use their gross proceeds received under arm's-length sales as their royalty value basis.

Summary of Comments: One commenter believes the use of gross proceeds as a method of valuation is flawed because it does not always represent the full value of the oil. Two commenters state that only independents should be allowed to use gross proceeds, while all major integrated producers should use index prices.

MMS Response: MMS's valuation rules have always followed the general premise that arm's-length gross proceeds represent market value and hence royalty value. However, the various MMS proposals and this final rule all include provisions that where an arm's-length sales contract does not reflect the total consideration received for the oil, MMS may require that the lessee value the oil under the appropriate index or benchmark value or at the total consideration received. For example, if in return for its oil the lessee received the contract sales price plus some other valuable goods or benefits—for example, a new car—the total consideration would include the contract price and the car's value. Also, we do not believe it is appropriate to apply different valuation methodologies based solely on whether the lessee is an independent producer or a major integrated company.

VIII. Responses to Public Comments on March 1999 Notice

On March 4, 1999, in response to requests by Members of Congress and parties interested in moving the process forward to publish a final rule, the Secretary announced he would reopen the comment period. MMS reopened the comment period from March 12, 1999, through April 12, 1999 (and later extended the comment period through April 27, 1999). The **Federal Register** notice announcing the reopening of the comment period (64 FR 12267 (March 12, 1999)) provided the contents of the August 31, 1998, letter from the Assistant Secretary for Land and Minerals Management, to the Senate outlining the direction the final rule might take on certain issues. The letter identified seven areas where MMS was considering changes in response to commenters' concerns: (1) Definitions; (2) valuation of oil sold by the lessee at arm's length; (3) valuation of oil sold after arm's-length exchange agreements or sold by an affiliate at arm's length; (4) valuation of oil not sold at arm's length; (5) location/quality adjustments to index prices; (6) transportation allowances; and (7) non-binding valuation guidance.

The MMS also scheduled three workshops during the comment period (Houston, Texas, March 24, 1999; Albuquerque, New Mexico, March 25, 1999; and Washington, DC, April 7, 1999) to obtain public input on specific issues that remained to be resolved.

MMS received 117 pages of comments from 16 commenters (three State agencies, two industry trade associations, eight oil and gas producers, two public interest groups, and one congressional office).

In response to the positions outlined in the August 31, 1998, letter to the Senate, industry participants at the workshops submitted a set of six unified industry proposals for discussion. These proposals were supported by both the major trade associations and the independent trade associations and became the primary focus of the workshops. Industry's written comments basically reiterated its support for these proposals. The States and public interest groups' comments were more general in nature and stated an overall objection to the reopening of the comment period and discussion of the ‘‘same old’’ issues. They objected to the continual delays in publishing a final rule and recommended that MMS proceed posthaste to a final rule based on index pricing. Specific comments by States and interest groups are included in the discussion of industry proposals.

(a) Use of Comparable Sales in Non-arm's-length Situations

Summary of Comments: For non-arm's-length sales, industry commenters proposed adoption of a menu of valuation alternatives that would center on using a weighted average of comparable arm's-length sales transactions at the lease. Under their proposal, a minimum of 20 percent of the lessee's production must be sold or purchased at arm's-length, including tendering programs. Other value benchmarks, including index, could be used in situations where comparable sales were not adequate. Industry advanced this proposal on the theory that it reflects the value of production ‘‘at the lease.’’ Industry commenters also maintained that using comparable sales would be a more accurate method of capturing the quality characteristics of lease production and it would avoid the complexity of calculating differentials between the lease and market center. Companies that tender their production under a competitive bidding process expressed strong support for using such programs to establish value for royalty purposes.

States continue to oppose lease-based benchmarks, because they believe arm's-length sales at the lease are limited, and they have concerns about the use of tendering programs. One State commenter stated that the comparable sales approach does not address the problem of undervalued field prices. That commenter plus an interest group recommended that MMS consider going forward with a rule specific to majors.

MMS Response: In the final rule, MMS did not adopt the industry-proposed comparable sales model to value production not sold at arm's-length. We continue to believe that there are meaningful spot prices applicable to production in all areas other than the Rocky Mountains. With the exception of the RMR, spot and spot-related prices drive the manner in which crude oil is bought and traded in the U.S. Spot prices play a major role in crude oil marketing and are readily available to lessees through price reporting services.

We believe spot prices are a better indicator of the value of production and are preferable to attempting to use comparable arm's-length sales in the field or area. Commenters have not demonstrated the consistent existence or availability of such transactions for volumes sufficient to use for royalty valuation. Contrary to the industry commenters, MMS believes that nationwide about two-thirds of crude oil production is disposed of non-arm's length. As previously mentioned, the general lack of competitive and transparent markets at the lease makes the attempt to find comparable sales transactions far inferior to the use of index prices.

The RMR, where reliable spot prices are not readily available, is an exception. About two-thirds of crude oil produced there is sold at arm's length, and there is not a reliable index price in that region. In addition, industry's proposal has substantial practical difficulties since companies are not privy to other companies' ‘‘comparable’’ sales transactions, and to the extent that such information may be available to MMS, it is unaudited for current periods. The final rule thus primarily uses index prices, adjusted for location and quality, to establish value for oil not sold at arm's length.

(b) Binding Valuation Determinations

Summary of Comments: Industry commenters proposed a provision under which MMS would provide binding valuation determinations on a case-by-case basis. Among other provisions, the determination would have no precedential value beyond the facts in the case. The MMS would have 180 days from the date the lessee submitted the request to make a decision, otherwise the request would be deemed approved. An MMS decision on a request would be subject to the existing appeals process. Industry commenters cited the need for obtaining timely valuation determinations that can be relied on for satisfying royalty obligations.

State commenters expressed general opposition to binding determinations, stating that information could be inaccurate, incomplete, or dated and that MMS should have discretion over issuing any binding determinations. A public interest group indicated it would support a binding determination as long as all of the information submitted is correct and verifiable and that the determination only applies to the requestor. A congressional commenter stated that this issue remains of concern and needs to be developed further.

MMS Response: See Section VI(f) above and the explanation of § 206.107 of the final rule in Section X below.

(c) Transportation Allowances in Non-Arm's-length Situations

Summary of Comments: Industry commenters proposed that transportation allowances in non-arm's-length situations should be based principally on the value of the service. That is, the allowance should be based on what companies pay under arm's-length contracts. Under the proposal, where more than 20 percent of the pipeline volume is transported at arm's length, an annualized volume-weighted average of the arm's-length rates would be used. Where less than 20 percent of the volume is arm's-length, the current MMS actual-cost method would apply; however, the rate of return would increase from the current level to twice Standard & Poor's BBB bond rate. Undepreciated capital investment would never be less than 10 percent of the original capital cost.

Industry commenters argued that they only agreed to the MMS actual-cost method under the 1988 regulations because of the provision to use FERC tariffs. They oppose MMS proposing to revoke use of tariffs without allowing an adequate transportation allowance rate that reflects the value of the production at the market centers. They also assert that the transportation allowance rate should recognize the risk associated with building pipelines. Furthermore, they point out that the current rate of return based on one times BBB is too low to accurately reflect a company's cost of capital.

State commenters agreed with MMS's position under the latest proposed rule. One congressional commenter stated that MMS should confer with FERC and develop a proposal that is more consistent with accepted public rate setting practices.

MMS Response: As explained elsewhere in this preamble, in the final rule MMS has deleted the FERC tariff exception. However, we note that independently of eliminating the FERC tariff exception, MMS has modified several provisions related to non-arm's-length transportation allowances, including new depreciation schedules if a transportation facility is sold, and a ‘‘base’’ investment level to which the rate of return could always be applied, as discussed further below. In the final rule, we have continued the use of the Standard and Poor's BBB industrial bond rate, for reasons discussed more fully below in the responses to the comments on the December 1999 proposal at paragraph IX(a).

(d) Adjustments to Downstream Values

Summary of Comments: Industry commenters stated that they would not be properly compensated for location and quality adjustments under the proposed rule. They contended that, with valuation being set downstream of the lease (*i.e.,* index prices), the prescribed location and quality adjustments do not arrive at a proper value at the lease, and they do not adequately compensate the lessee for the costs and risks associated with those midstream and downstream activities. They claimed that use of Form MMS–4415 would be unduly burdensome and too out-of-date for providing accurate location and quality adjustments to current index prices. They proposed alternatively that industry and MMS jointly develop a uniform monthly report or contemporaneous tables by region incorporating differentials reflective of actual recent market conditions. They also proposed adjustments for marketing activities.

MMS Response: MMS has always proposed that all reasonable location and quality adjustments be applied to the appropriate index, and believes this final rule permits those adjustments. Under § 206.112, the lessee may request approval from MMS for additional or alternative adjustments if necessary. However, for reasons explained in Section III(i), MMS maintains that marketing costs are not a proper deduction from royalty value and has retained this provision in the final rule.

Under the final rule, MMS will not publish location/quality differentials because MMS believes that lessees generally will have sufficient information to accurately determine location/quality differentials, with relatively rare exceptions. If a lessee disposes of its oil through one or more exchange agreements, it ordinarily should have the information necessary to determine adjustments to the index price. As a result of eliminating MMS-published differentials, the proposed Form MMS–4415 is not part of the final rule. Because MMS is not requiring the proposed form, it is not necessary to address the extensive comments MMS received regarding the content and timing of the form.

If the oil is not disposed of through exchange agreements, then the lessee is physically transporting the oil either to a market center or to an alternate disposal point (such as a refinery.) In that event, the lessee will have the necessary information regarding actual transportation costs to claim the appropriate transportation allowance.

(e) Definition of Affiliate

Summary of Comments: Industry commenters did not object to having separate definitions for ''affiliate'' and ''arm's-length,'' and in general, did not oppose the provision that ownership of 10 through 50 percent creates a presumption of control, as reinstituted in the July 1998 proposal. However, they recommended certain guidelines for lessees to rebut the presumption of control. If the lessee meets any of the following four criteria, they would be deemed to have no control over the affiliate: (1) The affiliated entity can take any relevant action without an affirmative vote of the lessee; (2) the lessee is not a general partner of a partnership; (3) the lessee is a natural person not related within the fourth degree to the affiliated natural person; and (4) the lessee's directors on the board of the affiliated company cannot block any relevant action of the affiliated company. Industry commenters also asserted that a lack of opposing economic interests cannot be assumed. However, they believe that if noncontrol is demonstrated, the existence of ''opposing economic interests'' has been established. One industry commenter indicated that MMS should bear the burden of proof in demonstrating a lack of opposing economic interest.

A public interest group commenter suggested that any economic interest in the other company should require index-based valuation. A State commenter suggested that ownership percentages should be only one of many factors to determine whether a contract is arm's-length and that any list of control rebuttal factors should be illustrative only.

MMS Response: See MMS response in Section VI(a).

(f) ''Second-guessing''

Summary of Comments: As stated above, industry commenters expressed significant concern that the additional regulatory language proposed in the July 1998 proposal at paragraph 206.102(c)(2)(ii) would lead to further uncertainty and misunderstanding regarding the lessee's duty to market production in arm's-length situations. Industry reiterated these concerns at the workshops. Particularly, they expressed concern that if a company sold production at the lease under an arm's-length arrangement, MMS might later ''second-guess'' the transaction and determine that the royalty should have been paid on a higher price than the company actually received, such as index. They proposed specific language to be added to the rule and preamble.

One State commenter also proposed specific regulatory language regarding ''second-guessing.'' A public interest group commented that it would support language that MMS will not second-guess arm's-length contract prices received, provided that lessees disclose balancing arrangements between themselves and the unaffiliated companies.

MMS Response: See Section VII(c) above.

IX. Responses to Public Comments on December 1999 Proposal

On December 30, 1999, MMS published a reproposal of the entire rule. The December 1999 proposal modified the prior proposals in a few respects, specifically:

• MMS proposed to eliminate MMS-published location/quality differentials, and, as a consequence, proposed to eliminate the previously-proposed Form MMS–4415.

• MMS proposed to permit a continuing return on investment component of the transportation allowance, even after a pipeline is fully depreciated, and to permit a new depreciation schedule when a lessee buys a pipeline at arm's length under certain conditions.

• MMS asked for comments on alternative rates of return, including multiples of the Standard & Poor's BBB bond rate and weighted average cost of capital methods.

• MMS proposed to change the definition of ''affiliate'' in light of the D.C. Circuit's decision in *National Mining Association* v. *Department of the Interior,* 177 F.3d 1 (D.C. Cir. 1999).

• MMS proposed value determinations issued by the Assistant Secretary for Land and Minerals Management that would be binding on both MMS and the lessee, and value determinations issued by MMS that would be binding on MMS and not the lessee.

• MMS proposed specific regulatory language regarding so-called ''second guessing'' of arm's-length sale prices.

MMS received approximately 700 pages of comments on the December 1999 proposal. In addition, MMS conducted public workshops in Denver, Colorado, on January 18, 2000, in Houston, Texas, on January 19, 2000, and in Washington, D.C. on January 20, 2000. The comments divide into 41 categories, addressed in (a) through (aj) below.

(a) MMS Should Modify the Rate of Return in Calculating Actual

Transportation Costs Allowances and Involve FERC.

Summary of Comments: Many industry comments favored increasing the rate of return in some fashion. Some suggested increasing the rate used in calculating the allowance to twice the Standard and Poor's BBB industrial bond rate. In some cases, industry provided detailed reports and analyses to support their claims.

Three States and an individual commented that increasing the rate of return above the BBB rate is unnecessary. They favor maintaining the provisions in the current regulations. The individual stated that the BBB rate already is for marginal credit risks and already is enhanced, hence a higher return is unneeded.

Several U.S. Senators encouraged MMS to utilize the expertise of FERC staff to develop costs of debt and equity applicable to pipeline investments for use in establishing a rate of return for lessees to use in calculating actual transportation costs for non-arm's-length transportation arrangements.

MMS Response: The fact that a lessee's overall operations are funded historically by some proportion of debt and equity does not imply that the resulting aggregate weighted average cost is appropriate for determining a proper transportation allowance for royalty purposes. Different projects and investments will be expected to involve very different levels of risk and generate different levels of returns. They also may be funded in different ways. For example, a pipeline investment likely would be much less risky than investment in a wildcat drilling operation and thereby command a lower rate of return.

MMS expects that lessees will finance pipeline investments in the least costly manner available. MMS's research indicates that most recent pipeline investments are financed largely through debt rather than equity. For those pipelines financed entirely by debt, the BBB bond rate is a very favorable rate to claim as a cost for the lessee, because most large operators can borrow money at lower rates. Also, equity financing is typically more costly than debt financing.

The Standard & Poor's BBB industrial bond rate (BBB rate) that MMS currently uses typically falls between the cost of borrowing for large integrated oil and gas companies and the return that these firms are expected to earn on their capital investments. Therefore, given the predominance of debt financing for pipeline investments, MMS believes the choice of the BBB rate for the cost of capital is entirely reasonable.

The industry proposes using a weighted average cost of capital. Industry states that this weighted average cost is approximately 2.2 times the BBB bond rate. That is the basis of industry's proposal to use 2 times the BBB rate in transportation allowance calculations.

However, MMS believes that the companies used in industry's weighted average cost of capital calculation (those in Standard Industrial Classification (SIC) code 131) are less representative of lessees that typically build or own pipelines (including through affiliate arrangements) than those listed in SIC code 291. We believe code 291 is more appropriate because it includes major integrated firms, and therefore more closely represents the body of companies that typically would be involved in owning or constructing pipelines.

Also, we agree with industry's proposal to calculate a before-tax rate of return. Royalties are calculated before tax, so the rate of return used should be a before-tax rate as well. However, in adjusting certain after-tax information to obtain before-tax estimates, we did not use the 35 percent marginal tax rate used by industry. Instead, we used the 19 percent average tax rate that we find find is more appropriate for SIC code 291 firms.

Industry's calculation of weighted cost of capital is further exaggerated because it uses the BBB rate as the debt rate. As explained above, we believe that the BBB rate generally is higher than these companies' actual borrowing rates would be.

Further, we believe the equity rate used in industry's calculations was not appropriate because the equity rate applicable to companies in SIC code 131 is higher than the equity rate for companies in SIC code 291.

Even if, arguendo, we accepted the premise of using a weighted average cost of capital as the rate of return, MMS has found, using more appropriate SIC codes, tax rates, debt rates, and equity rates, that the average cost of capital is much lower than the 2.2 times BBB that industry calculated. MMS therefore concluded that industry's proposal is not well founded. MMS concludes that the BBB bond rate is an appropriate rate of return, and we have retained it in the final rule. We also conclude that since the BBB bond rate is adequate as a rate of return used in calculating actual transportation costs for royalty purposes, there is no need for MMS to utilize the expertise of FERC staff to develop costs of debt and equity.

(b) Rulemaking Process

Summary of Comments: One State commented that it would like to be involved in valuation requirements that affect it. Further, the rule should include a provision that the affected State may review valuation determinations.

A private organization questioned the rulemaking process in light of certain payments made to Department officials from proceeds paid to relators as a result of settling certain litigation brought under the qui tam provisions of the False Claims Act. It urges a delay in the rule until all matters associated with these payments are fully examined.

MMS Response: We understand the importance of the royalty income for each State and the fact that valuation decisions affect royalty revenues that are shared with States. States already have a major role in the process, through delegations of audit authority under 30 U.S.C. 1735, many informal consultations, and comments on proposed rules such as the comments submitted in this instance. We intend to continue this cooperative relationship. However, valuation determinations ultimately are MMS's responsibility.

The payments made to a Department employee from litigation settlement proceeds are the subject of a pending investigation. In that respect, MMS knows of no grounds for delaying this rulemaking.

(c) ''Second Guessing''

Summary of Comments: An industry comment stressed support for the concept of MMS not ''second guessing'' industry's decisions in disposing of crude oil production. However, the commenter would like to see the concept expanded in the preamble and the associated sections within the rule itself.

MMS Response: MMS continues to reiterate that it will not ''second guess'' a company's decision on how it disposes of production. We have emphasized this at several points, both in the text of the rule and in the preambles to this rule and previous proposals. We do not believe that additional discussion would be helpful. As discussed above, MMS has rarely, if ever, ''second guessed'' the value received in an arm's-length sale of oil, so we cannot use actual experience that would provide a basis for elaboration.

(d) Spot Prices as a Marker of Value

Summary of Comments: Several industry commenters reiterated the assertion that spot prices do not reflect lease values even after adjusting for quality and location. MMS fails to provide any analysis showing that spot prices do reflect lease value. The use of these prices inflates the actual value of the production at the lease, in violation of the lease terms.

Further, some industry commenters questioned the use of the Alaska North Slope (ANS) spot price as a marker for west coast oil. The State of California reiterated its belief that ANS prices are a valid measure of value.

MMS Response: MMS addressed the use of spot prices previously. The comment here was a prominent theme of the comments on the February 1998 proposal. See Section VI(e) above.

MMS continues to believe ANS is a valid measure of value for west coast production. However, there is language in the rule allowing review and changes should an index price become invalid.

(e) Nearest Spot Prices

Summary of Comments: Some comments from industry urged that if MMS is going to use index pricing, lessees should have the option of using a more distant index price if that index better reflects sales of oil more similar in quality to the lessee's Federal production, or if that index better reflects the location specified in the lessee's exchange agreements.

MMS Response: MMS's intent in the December 1999 proposal and this final rule in requiring lessees to use index prices at the market center nearest the lease is to correlate both proximity to the lease and quality similarity. If lessees could choose other market centers, the rule would become ambiguous and more vulnerable to manipulation.

(f) Unclear Whether Spot Price Applies to Trading Month or Calendar Month

Summary of Comments: Several industry commenters were not sure if the spot price to be used under the rule means the price that applies to the trading month or to the production month. They would like to see a clarifying example.

MMS Response: The final rule and this preamble clarify that the spot prices to be used in index value calculations are the prices for the trading month concurrent with the production month. The term ''trading month'' is a defined term in the final rule, and means the period during which crude oil trading occurs and spot prices are determined, generally for deliveries of production in the following calendar month.

In effect, the spot prices used will be the prices published during the production month for ANS crude, and prices published principally during the production month for other indexes. For example, a publication may publish prices between approximately the 26th day of month one and the 25th day of month two. That period will be the trading month, and the spot prices published in that trading month will be used to value, for royalty purposes, production from a Federal lease in month two).

Thus, continuing the example, if the production month is June and the oil is produced outside California/Alaska, and the trading month is May 26–June 25, you would compute the average of the daily mean prices using the daily spot prices published in the appropriate MMS-approved publication for all the business days between May 26 and June 25 (for delivery in July).

As indicated previously in this preamble, in the final rule we have adopted the index timing method proposed in the January 1997 proposal and not the method proposed in February 1998 and December 1999.

(g) Tendering Should Be an Option for Oil Not Traded at Arm's Length

Summary of Comments: Several comments from both industry and a group of U.S. Senators indicated that tendering should be used as a valuation methodology in all areas of the country, not just as a benchmark in the RMR. Further, MMS restrictions on tendering in the RMR are too severe. MMS can ease its restrictions and still prevent ''gaming''.

MMS Response: MMS addressed the overall appropriateness of tendering programs when similar comments were raised in response to the February 1998 proposal.

(h) Use of FERC tariffs in Lieu of Actual Costs

Summary of Comments: Again, industry submitted numerous comments supporting the position that FERC tariffs should be permitted as allowances because they recognize the real cost structure of pipeline investments; MMS allowances do not recognize these costs. Several State comments indicated that FERC tariffs are not appropriate and should not be used as allowances.

MMS Response: MMS addressed the appropriateness of FERC tariffs as allowances in the February 1998 responses to public comments.

(i) The Two-Year Election Requirement

Summary of Comments: Several comments from industry expressed concern that the requirement that a lessee declare for a 2-year period whether it will use gross proceeds or index pricing is too severe. Further, MMS should allow the election on a lease-by-lease basis rather than for all production and in intervals less than 2 years.

A State commented that it generally favors the 2-year valuation election as a method to ensure that industry does not ''game'' the valuation methods.

MMS Response: MMS agrees with the State comment that 2 years is needed to ensure that lessees do not have any incentive to ''game'' valuation methods. However, MMS acknowledges that it may be problematic for a lessee to have to declare an overall valuation method for all of its properties when circumstances may dictate different approaches for properties that are widely geographically separated or from which production is marketed in different ways. Therefore, in the final rule, MMS is requiring lessees to make the 2-year election on a property-by-property basis, *i.e.,* for a unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement).

(j) MMS Ignores Alternative Valuation Methodologies for Non-Arm's-Length Transactions

Summary of Comments: A consultant hired by industry claims that MMS has not addressed all of the alternatives that can arrive at lease value. It has not explained why RIK will not work in all circumstances. Other comments asserted that MMS would be able to eliminate valuation problems if it were to take its royalty in kind. Most States favor the approach of using index prices. One State is open to tendering if a lessee can demonstrate that its program will establish competitive prices.

MMS Response: MMS consulted with crude oil experts in economics, marketing, and related areas in the formulation of these rules. It has consulted with industry, States, and other interested parties for more than 4 years. During this time MMS held workshops addressing alternate proposals from these parties and made numerous refinements and revisions to its proposals. MMS has addressed alternate valuation proposals in the sections addressing comments received on earlier proposals before the December 30, 1999 proposal.

It is not incumbent on MMS to prove that RIK will not work in all circumstances before issuing a final rulemaking on oil valuation. The statutes and lease terms give MMS the option of taking royalty in value or in kind. As a steward of publicly owned resources, MMS is responsible for receiving fair value for development of publicly-owned resources.

(k) MMS Has Not Fully Considered the Advantages of a Lease-Based Comparable Sales Valuation Methodology

Summary of Comments: Industry commenters still embrace comparable lease-based arm's-length sales to value production not sold at arm's length and claim that their consultants' work demonstrates that there are viable markets at the lease.

MMS Response: MMS has addressed the concept of comparable sales in multiple workshops attended by State and industry representatives and in sections containing responses to previously submitted comments in this rulemaking process. In support of their position, industry commenters offer the analyses prepared by Joseph Kalt (Kalt) and Kenneth Grant (Grant). For the west coast market, industry includes the comments of Samual Van Vactor. In support of their position, Kalt and Grant cite an extensive data base of lease-based arm's-length transactions that they say demonstrate that a market exists at the lease. We are aware that this database apparently exists because Kalt cited it in support of industry's position in a presentation to a congressional subcommittee reviewing this rulemaking process.

MMS also understands that this same database has been cited in several judicial proceedings where royalty payments were valued at posted prices. MMS has not seen the database containing these transactions because it was not provided with the comments submitted by Kalt and Grant. MMS has no way of verifying whether this database is accurate or whether or to what extent it supports Kalt's and Grant's thesis. We have no way of knowing whether the database includes transactions that MMS would not regard as arm's-length sales, whether it includes buy/sell exchanges within arm's-length sales, or whether it may involve other possible problems. It is also unclear whether any double counting of information may have occurred, since multiple parties' sales and purchase information apparently are contained in the database.

MMS cannot rely on data it has not seen and has not examined. MMS does not believe that industry has provided convincing evidence or analysis to show that a competitive market exists at the lease throughout the domain of Federal leases.

Another consultant hired by industry, Samuel Van Vactor (Van Vactor), claims that ANS spot prices are poor indicators for the market value of California crude oil. In support of his position, Van Vactor cites several difficulties in comparing ANS crude to California crude oils.

- ANS is of better physical quality than most California crude oil.
- Line 63 spot prices of California crude yield lower values than ANS.
- Gravity schedules on posted price bulletins and pipeline gravity banks are not intended to make comparisons between crude oils from different fields.
- MMS's method is more cumbersome than industry's comparable sales method.
- MMS disagrees with Van Vactor's position and reasons. While the quality of ANS is clearly different than most Federal California crude oil, after adjustments are made for gravity, sulfur, and location, it is a good proxy in valuing oil not sold at arm's length. ANS spot prices have the advantage of regular transactions of sufficient liquidity to establish a fair market price. Spot prices for Kern River crude and Line 63 are suspect indicators of market value because they reflect only thinly traded volumes. Additionally, Line 63 is a blend of heavy and lighter crude oil and, when refined, yields a different product slate than ANS and other California crude oils.

Van Vactor's criticism of the use of posted price gravity schedules and pipeline gravity banks for making adjustments between different fields ignores their common use by industry in exchange contracts involving different quality crude oils from distant locations. See Review of Selected Technical Reports on MMS's Proposed Federal Oil Rule and Supplemental Rule, prepared by Innovation and Information Consultants, Inc., dated September 25, 1997, p. 5. That review observes:

> Finally, Van Vactor argues that one cannot apply the California gravity price differential as a quality adjustment to ANS. He claims such adjustments are only meant to measure small deviations around the gravity actually being delivered and are not intended to be applied across crude fields or to compare with different crude oils. He also claims that when comparing ANS with California crudes of identical quality, ANS sells for $0.50 to $1.00 per barrel more. We disagree with his reasoning and its factual basis. First, it can be demonstrated that the interfield (the gravity adjustment factor across different fields) and the intrafield (the adjustment factor used in posted price bulletins to adjust for gravity variations within a field) gravity price differential are very nearly the same. [Citing ''West Coast Crude Oil Pricing,'' Department of Energy, 1988.] Second, the oil companies regularly apply the gravity price differential (GPD) on exchange agreements covering many different crude oil types, gravity levels and fields within and outside California. Indeed even when companies are trading ANS for California crude oils, they often apply the California gravity price differential (or something lower) to adjust for differences in quality. Third, pipelines such as the All America pipeline which transports both ANS and California crude oils (heavy and light) utilizes a gravity bank that is very similar to the California posted price gravity differential. Furthermore, this bank can be applied to widely varying gravities (10–30° API).

Id.

On at least one occasion involving a gravity bank dispute between producers of ANS crude oil, an integrated company argued for the use of California posted price gravity schedules in making adjustments between different grades of ANS crude that was shipped via the Trans-Alaska Pipeline. See, Prepared Direct Testimony of Karl Richard Pavlovic, dated January 11, 1998, in *Exxon USA, Inc.* v. *Amerada Hess Pipeline Corp.,* Docket No. OR96–14–000 before the Federal Energy Regulatory Commission. In short, Van Vactor's arguments against the use of ANS for valuing California Federal crude oil are at odds with actual industry practices. Additionally, ANS prices are transparent and adjustments for location and quality can be made that will provide a value at Federal leases for royalty purposes.

Finally, MMS disagrees with Van Vactor's claim that the ANS methodology is more cumbersome than a comparable sales method. A comparable sales method would be burdensome for both MMS and industry. In many instances companies would not have sufficient transaction information to arrive at a reasoned calculation of value. Under the current regulations, comparable sales methods (i.e., the benchmarks) lead to a significant audit burden for both industry and MMS. Moreover, MMS does not believe that in most instances in California there are sufficient arm's-length sales at the lease to derive an accurate comparable sales value.

(l) Posted Prices are Valid Indicators of Value for Non-Arm's-Length Transactions

Summary of Comments: Some industry commenters continue to assert that postings represent market value at the lease. They cite the recent jury decision in the Long Beach II trial [i.e., the Exxon case] as evidence for this position.

MMS Response: In the various proposals that have resulted in this final rule, MMS has discussed at great length the reasons why we believe posted prices no longer represent market value. The reasons why the jury's decision in the Exxon matter does not imply that posted prices are a valid indicator of value, and why it is not contrary to this rule, are covered in detail in Section X of this preamble in the discussion of the provisions of § 206.103.

(m) MMS Treats Producers Inequitably by Not Allowing Arm's-Length Production To Be Valued at Index

Summary of Comments: MMS received several comments that lessees should be allowed to use index pricing where tracing of arm's-length dispositions would prove overly burdensome. Others commented that MMS should provide the option to value all arm's-length production under index pricing.

MMS Response: The principle that gross proceeds is the primary measure of value in arm's-length transactions has been retained under these regulations. This means that a lessee must be able to account for actual receipts under an arm's-length contract. This is consistent with the principle that arm's-length contracts should be the basis for valuation whenever possible.

In the final rule, as in the December 1999 proposal, and for the reasons explained in that proposal, MMS has provided the option for lessees to choose to report and pay on index values only after one or more arm's-length exchanges or after sales to an affiliate. We do not believe that use of index prices when production initially has been sold at arm's length should be expanded.

(n) Use of Alternate Index Prices

Summary of Comments: There were some industry comments suggesting that MMS use Line 63 and Kern River Spot prices in place of ANS. Several comments suggest using index prices from more distant markets if the crude oil indexed better approximates quality parameters than a nearby indexed crude oil.

MMS Response: MMS does not believe that the Line 63 and Kern River spot prices are dependable indicators of market value for reasons explained elsewhere in this preamble. We also have explained elsewhere why we do not believe that as a general rule lessees should be allowed to use index prices from more distant markets.

(o) Use of Benchmarks Outside the Rocky Mountain Region

Summary of Comments: Industry commented that the benchmarks applicable to the RMR should apply everywhere. The RMR benchmarks should be a menu and not a hierarchy, and MMS should modify them to allow lessees to use either tracing or index pricing where tendering programs do not meet MMS standards. The RMR benchmark that uses a volume-weighted average of sales prices must also include adjustments for gravity. Also, MMS has not explained why comparable sales are used in the proposed Indian rule but not in the Federal rule.

MMS Response: MMS has addressed the need for a series of benchmarks for the RMR in earlier parts of this preamble and in earlier versions of this rulemaking. The reasons for prescribing in the final rule an initial benchmark, followed by a choice between two other benchmarks if the first does not apply, have been explained elsewhere in this preamble. In other parts of the country, reliable index prices exist. MMS has addressed the concern about gravity differences in the RMR comparable sales methodology by requiring that gravity be normalized before a volume-weighted average of prices is considered.

The proposed Indian oil value rule does not include comparable sales as the commenters here imply. The ''major portion'' provisions in Indian leases are not what the commenters in this rulemaking have suggested.

(p) Binding Value Determinations

Summary of Comments: Several U.S. Senators stated that MMS should issue binding value determinations that are appealable administratively. (In light of the text of the December 1999 proposal, it appears that the congressional commenters are suggesting that MMS, and not just the Assistant Secretary, should issue value determinations that are binding on the lessee as well as on MMS.) Industry wants MMS to broaden the kinds of binding determinations it provides, and then only prospectively. These determinations should be issued expeditiously and be appealable. The limits on determinations are overly restrictive. Fact-specific determinations should be issued. The uncertainty surrounding determinations makes the rule unworkable. MMS should expand the circumstances in which lessees may receive determinations.

MMS Response: The final rule provides that MMS will be bound by MMS determinations, and that both MMS and the lessee will be bound by Assistant Secretary determinations. MMS disagrees with the suggestion that value determinations by MMS should be appealable administratively, because they are not binding on lessees. We see no need to expand the number of potential administrative appeals when enforcement of the measure of value in an MMS determination (should the lessee disagree with and not follow it) depends on whether MMS later issues an order to pay.

We disagree that the scope of value determinations is overly restrictive and we do not agree that MMS should be required to issue value determinations in every case in which a lessee asks for one. Issuing value determinations is not always appropriate, and MMS must retain discretion in this respect. We also do not believe that there is ''uncertainty'' surrounding determinations or that the procedure in the December 1999 proposal and this final rule is ''unworkable.''

(q) Binding Determinations—Allegedly ''Penalizing'' Lessees

Summary of Comments: Some commenters argued that the provision about not penalizing a lessee for failing to follow a value determination by MMS is illusory and amounts to a form of ''Hobson's choice.'' The commenters say that to require lessees to subject themselves to penalties in order to challenge determinations they disagree with is unsound policy. MMS should apply the principle that the mere existence of a higher selling price does not mean that MMS will question the validity of the proceeds in any transaction.

MMS Response: MMS does not agree with this characterization of the value determination process. If a lessee disagrees with a determination by MMS, it has the option of not following the determination. The burden will lie with MMS to issue an order to pay on the value basis contained in the determination. The lessee is not in any different position than in any other circumstance in which it may disagree with MMS's position on a valuation issue. We are unable to see how this in any way ''penalizes'' the lessee or imposes on it a ''Hobson's choice.''

Finally, as explained elsewhere in this preamble, the existence of a higher selling price does not in itself imply that the lessee has breached its duty to market or that the arm's-length gross proceeds would not be accepted as royalty value.

(r) Requirement To Identify Other Lessees When Requesting a Value Determination.

Summary of Comments: At least one commenter argued that the requirement in the December 1999 proposal that a lessee must identify record title or operating rights owners when requesting a valuation determination is unnecessary.

MMS Response: MMS believes it is appropriate to require lessees to identify other operating rights owners or record title owners to the extent that the lessee knows who they are because they may be affected by the analysis or conclusions of a value determination in a manner similar to the lessee who requested it. If production for which those other parties may be liable for royalty payments is affected by the results of a value determination, MMS needs to have this information to proceed expeditiously.

(s) Clarification of Value Determination Procedures

Summary of Comments: At least one commenter suggested that MMS should issue guidelines in the rule to help lessees determine if their transactions are at arm's length. The commenter argued that the final rule should better clarify what decisions do and do not come under the valuation determination process.

MMS Response: With the change made in the definition of affiliate, we believe the final rule provides sufficient criteria to determine what transactions are at arm's length in the vast majority of situations. The final rule at § 206.107 explains that MMS will not provide valuation determinations in response to requests for guidance on hypothetical situations or matters that are the subject of pending litigation or administrative appeals.

We also removed the provision in the December 1999 proposal that we would not provide valuation determinations where the request dealt with matters ''inherently factual'' in nature. We proposed not to address such requests because the purpose of providing valuation determinations is to take given facts and render an interpretation of how they should be applied in a given situation, not to interpret what the actual facts are. But since the term ''inherently factual'' may mean different things to different people and cannot be precisely defined for purposes of this rule, we removed this provision in the final rule. We still do not intend, however, that valuation determinations would be given just to determine the facts involved in a given situation.

Further, we did not include in this final rule the provision in the current rule at § 206.102(g) that the lessee may use its proposed value for royalty payment purposes until MMS provides a value determination. MMS does not want to be in the position of having to accept royalty payment on a value it may find unacceptable, no matter how short the period may be between the lessee's request for a value determination and MMS's response. MMS will act as expeditiously as possible on such requests, but sometimes policy interpretations may be required or other complications may arise.

This preamble at Section VI(f) also explains some types of situations where value determinations may or may not be appropriate. Value determinations are issued only under § 206.107, in response to a specific request for a value determination. An example might be where the lessee operates in the RMR and approaches MMS for approval to use results from its tendering program to value its production that is not sold at arm's length. Or, if the lessee has no tendering program, it might ask MMS to determine whether purchases and sales by it and its affiliate are at arm's length and of sufficient quantities to permit use of the second RMR benchmark. Requests not covered under § 206.107 include, for example, those under the fourth benchmark for the RMR where the Director establishes an alternative valuation method (§ 206.103(b)(5)), calculation of a value at the refinery when the adjusted index price yields an unreasonable value (§ 206.103(e)), and calculation of a location/quality differential when the lessee does not have its own information to calculate the differential (§ 206.112(f)). MMS will respond to these requests, but they will not be handled under the value determination procedures.

(t) Timely Value Determinations

Summary of Comments: Some commenters express a lack of confidence that MMS will be able to issue timely determinations. They say that MMS should rule on all issues and provide timely answers, even if a negative decision results. The States are concerned about MMS making decisions based on incomplete information.

MMS Response: MMS has identified some types of matters for which value determinations probably are not appropriate, such as hypothetical situations or matters that are the subject of pending litigation or administrative appeals. It is in MMS's interest to expedite value determinations so as to resolve as many matters as possible and avoid a backlog. (See also our response at (s) immediately above.) As for the States' concern that MMS will make decisions based on incomplete information, MMS does not intend to make a determination until the lessee provides all the pertinent facts, documents, and analysis. In the rare event that a misstatement or omission of the material facts occurs, or the facts ultimately developed are materially different from the facts on which the guidance was based, MMS could change the determination retroactively.

(u) State Involvement in MMS Value Determinations

Summary of Comments: State commenters said they would like to be involved in the decision-making process when binding determinations affect their revenue. California is concerned with lessees possibly requesting valuation determinations on no more grounds than an asserted belief that a methodology required under the rule is not applicable. The State commenters argued that prospective valuation determinations should ''sunset'' after 2 years, within which time the lessee must demonstrate that the circumstances continue to apply.

MMS Response: MMS is mindful of States' concerns in valuation issues. As a general practice, MMS consults with States in preparing valuation determinations, but the ultimate decisions with respect to value determination requests rest with MMS and the Assistant Secretary. MMS does not believe that lessees have any incentive to file spurious or unsupported requests for value determinations. If MMS receives a spurious or frivolous request, it will be rejected. (Such a situation would be another example of an appropriate circumstance in which MMS would decline to issue a determination.) MMS does not believe it is appropriate to include a ''sunset'' provision in every determination as a matter of course. However, MMS may include such a provision where circumstances indicate that the situation addressed in the determination is likely to change, or that the matter should be reexamined after some interval.

(v) Location and Quality Differentials

Summary of Comments: Industry commenters uniformly favor removing the requirement to submit Form MMS–4415, as proposed in the December 1999 proposal, but many express doubts that MMS will accept the location and quality differentials they derive and use in reporting royalties due. Industry commenters also do not believe that MMS can determine meaningful differentials for them when they are required to pay on an index value, but do not have actual information from their own contracts to determine these differentials. These commenters question how a company would challenge an MMS determination. Industry wants to be able to appeal determinations of differentials.

MMS Response: If a lessee can document the differentials it uses from its arm's-length exchange agreements or other reliable evidence, MMS will have little reason to dispute the lessee's use of those differentials. If MMS determines a location/quality differential, it will do so on the basis of the best information available to it. If the lessee disagrees with MMS's determination and the lessee and MMS are unable to resolve the disagreement, MMS would issue an order to the lessee to use MMS's differential. That order would be appealable.

(w) Elimination of Form MMS–4415 and Validity of Location/ Quality Differentials

Summary of Comments: One State commenter supports keeping the Form MMS–4415 for now, with the provision that MMS can always eliminate the form in the future. That State asserts that it is better to collect the information now and realize later that the form is not needed rather than to be forced to work without it. One State believes that using location differentials to alternate disposal points (such as a refinery) is not appropriate, and that location differentials should be between the lease and the index pricing point.

This commenter also asserts that exchange differentials will not accurately reflect the difference in value between the lease and the index pricing point. It proposes using gravity and sulfur banks in the pipeline tariffs for quality differentials. A public interest group recommends standardized location differentials.

MMS Response: One of the most contentious issues arising from prior proposals in this rulemaking process has been the requirement for lessees to submit information about their exchange agreements on Form MMS–4415. These lessees correctly point out that the information is not for their benefit, but would be used only in a small number of cases where a lessee must pay on an index value, but does not have access to actual location/ quality differential information. While it would be preferable to have comparable exchange differential information, MMS must weigh this benefit against the burden and cost that it would impose on industry and MMS. After considerable discussions with all interested parties, MMS has determined that the burdens and costs would outweigh the potential benefits. MMS anticipates that it will have to determine differentials for lessees in only a limited number of circumstances.

(x) Economic Analysis of Lease Markets

Summary of Comments: On behalf of industry, one commenter asserts that MMS has ignored basic economic principles in arriving at the conclusion that lease markets are not competitive. MMS's conclusions, this commenter says, are based on contradictory statements, unsubstantiated claims, and misinterpretation of economic principles and significant facts about the domestic crude oil market. He states that the lease market contains significant and recurring volumes of crude oil sales moving in outright sales between unrelated, well-informed buyers and sellers with access to information. Competition allows each party to protect its interests.

MMS Response: MMS does not agree with this commenter and does not believe that his analysis of the lease market is complete. First, the commenter's analysis ignores the principle that the lessor is entitled to share in gains derived from the lessee's marketing activities. Second, relying on supposed comparable sales at the lease results in relying on prices paid to captive sellers in many instances. Those prices will tend to be below the true market value of the oil. Third, the commenter equates posted prices to ''price transparency.'' This assumption contradicts statements that companies with tendering programs have made during the rulemaking process, and cannot be defended under any concept of ''price transparency'' that we have been able to find. The fact that prices paid in arm's-length transactions frequently include a premium over the posted price refutes the commenter's assumption. The principles of competitive markets that this commenter outlines in fact occur at market centers with spot prices. Therefore, MMS believes it is appropriate to establish value for non-arm's-length transactions by using spot prices, with adjustments for location and quality.

(y) Alleged Different Treatment of Integrated and Non-Integrated Producers

Summary of Comments: Some industry commenters assert that integrated producers should not be treated differently than non-integrated producers. Also, producers in the RMR have more options than producers in other regions. MMS should allow the same standards for all Federal leases, including tendering and comparable sales.

MMS Response: MMS disagrees that integrated producers are treated differently than non-integrated producers under either the previous proposals or this final rule. How producers value production and pay royalties under this final rule depends in large measure on how they choose to market their production. If a producer sells its production outright at arm's length, it pays based on gross proceeds. If not, it pays royalties using either the index pricing methodology, an applicable benchmark (for production in the RMR), or on the basis of an arm's-length sale price following either inter-affiliate transfers or arm's-length exchanges. These principles apply to both integrated and non-integrated producers.

(z) Final Rule Implementation Date

Summary of Comments: Industry commenters assert that MMS should allow for adequate time for industry to completely update its systems before the final rule becomes effective. (According to some industry commenters, it will require at least until the beginning of next year to update their systems.) A number of public interest groups stated that they expect a final rule in March 2000. A citizen and the State of New Mexico also favor immediate implementation of this rule.

MMS Response: MMS understands that this rule will require some adjustments to many lessees' systems. It has extended its earlier proposed effective date to June 1, 2000, the first day of the first month more than 60 days after the publication date of this rule to allow lessees to make needed adjustments. MMS further has provided for a ''grace period'' in § 206.121 that allows lessees to make adjustments to royalty payments for production in the first 3 months after the effective date of the rule without liability for late payment interest if the adjustment results from a system change necessary to comply with this rule. Lessees may get interest bills, but if they demonstrate that the adjustment generating the bill resulted from system changes necessitated by the rule, MMS will credit the bill. MMS believes that the ''grace period'' should allow adequate time for lessees to make necessary adjustments.

(aa) The Lessee's Duty to Market Production at No Cost to the Lessor

Summary of Comments: Some industry commenters provided extensive comments on MMS's analysis in the December 1999 proposal of the lessee's duty to market production at no cost to the lessor and related issues (e.g., the commenters' view of valuing production ''at the lease'' and gain realized from ''downstream'' sales). (The analysis in the December 1999 proposal is reiterated with some additional explanation in Section III(i) above.) The industry commenters cite numerous

State court decisions, discuss IBLA precedents and various Federal court decisions at great length, and dispute the existence, scope and implications of the lessee's implied covenant to market the production for the mutual benefit of the lessee and the lessor. The State commenters support the MMS's position on the lessee's duty to market as reflected in the December 1999 proposal.

MMS Response: The lessee's duty to market at no cost to the lessor is the subject of pending litigation. Industry has challenged a provision in the Department's December 16, 1997, gas transportation allowance rule that is virtually identical to the provision in the several proposals in this rulemaking and in this final rule (62 FR 65753). See, *American Petroleum Institute* v. *Babbitt,* Civil No. 98–631 and *Independent Petroleum Association of America* v. *Armstrong,* Civil No. 98–531 (D.D.C.) (consolidated). The ultimate resolution of this issue likely will lie with the courts. MMS believes the final rule is well within the agency's authority and reflects existing law governing Federal leases.

(ab) Affiliation and Control

Summary of Comments: Some industry commenters believe that tests to determine control (and, consequently, affiliation in the event one person owns less than 50 percent of the voting securities of another) are too subjective.

MMS Response: As explained elsewhere in this preamble, after the D.C. Circuit's decision in *National Mining Association* v. *Department of the Interior,* 177 F.3d 1 (D.C. Cir. 1999), MMS has no alternative but to conduct a fact-specific inquiry in cases where one person owns less than 50 percent of the voting securities of another. The situations vary widely. This rule identifies some of the key factors which MMS will examine in evaluating whether one person controls another. These factors are objective, not subjective, indicators. Their application depends on the facts of a particular case.

(ac) Production ''Tracing'' Issues

Summary of Comments: Some industry commenters claim that tracing will involve multiple valuation determinations where none were needed before, and may make implementation of the rule impossible.

MMS Response: The facts that oil produced from any particular lease or unit may be commingled with oil produced from other properties, and that the combined quantities may be disposed of through multiple transactions at more than one location, are not new. In many circumstances, the MMS valuation rules that hitherto have been in force require allocation of production from multiple sources and multiple dispositions if lessees are to pay royalty correctly. In fact, this rule provides the option to use index-based valuation, in which no ''tracing'' would be required, in certain circumstances.

(ad) Tracing in Relation to Exchange Agreements

Summary of Comments: Some States are concerned about the issue of tracing production after multiple exchanges. They assert that value can be masked in this process due to commingling and other factors. They favor limiting the number of exchanges or using a weighted average price if only one exchange exists. One public interest group favors limiting the number of exchanges to two.

MMS Response: In cases where lessees have multiple exchanges involving production from a Federal lease, they will have to be able to account for adjustments due to location/quality differentials or transportation costs. These adjustments will be subject to audit. Lessees who dispose of production through arm's-length exchanges followed by an arm's-length sale have the option of valuing the production under either gross proceeds or index (§ 206.102(a) or § 206.103, respectively). (Lessees who dispose of production through non-arm's-length exchanges or who refine their production must use the index value under § 206.103.) If the lessee uses the index value under § 206.103, the considerations the commenters raise are irrelevant. If the lessee values the production according to the arm's-length gross proceeds following one or more arm's-length exchanges, it must be able to support its adjustments.

(ae) Treatment of and Effect on Affiliated Pipelines

Summary of Comments: One pipeline commenter who is affiliated with producers said that the December 1999 proposal improperly affects affiliates negatively in several respects. This commenter said that MMS is trying to control the affiliate's pricing, transportation, and contracting behavior even though it is not a party to the lease. It also said that requiring production of an affiliate's pricing information could expose the affiliated pipeline to ''unreasonable allegations of antitrust violations.'' This commenter also says that the rule discriminates against affiliated transportation arrangements. The commenter further asserts that the rule imposes ''enormous'' administrative costs on affiliates and designees, which, it says, MMS ''grossly underestimated.'' The commenter says that the rule would require multiple valuation methodologies, which in turn require new accounting systems and additional manpower. Finally, this commenter asserts that MMS lacks the statutory authority to require affiliates to make their records available.

MMS Response: MMS disagrees with this commenter's characterizations. This rule does not control an affiliate's behavior. The fact that transactions with an affiliate may affect how production is valued for royalty purposes does not imply that the rule somehow ''controls'' the affiliate's behavior.

MMS does not believe that requiring production of an affiliate's information would create any exposure under the antitrust laws. In the commenter's own words, it fears that ''[p]laintiffs lawyers might try to concoct'' a Sherman Act theory. The commenter apparently does not believe that any such concocted theory would have any merit, and neither do we.

As explained elsewhere in this preamble, the rule does not discriminate against affiliated transportation arrangements. In both arm's-length and non-arm's-length arrangements, the lessee may deduct its actual costs of transportation.

We do not believe that the commenter has justified its assertion of ''enormous'' administrative costs resulting from this rule. Although the rule does require changes in valuation methodology in some respects, no one has demonstrated that it requires lessees to construct completely new systems. Indeed, although companies have asserted repeatedly that the rule will result in large costs, none has attempted to quantify such costs.

MMS believes that the commenter's assertion that the new rule requires ''multiple valuation methodologies'' is misplaced. We doubt that any lessee with more than a few leases valued all of its production for all of its leases in the same way under the previous rules. Under the prior rules, some dispositions resulted in using arm's-length gross proceeds as royalty value, while others resulted in using the ''benchmarks.'' MMS does not believe this rule is more difficult to apply than the earlier provisions; indeed, we expect that the opposite is true.

Finally, the commenter's argument that MMS does not have statutory authority to require affiliates to produce their records is wrong. The commenter relies on the provisions of FOGRMA Section 103(a), 30 U.S.C. 1713(a), for the proposition that MMS may require production of records only through the first non-arm's-length transfer. This position was expressly rejected in *Shell Oil Co.* v. *Babbitt,* 125 F.3d 172 (3d Cir. 1997). Contrary to the commenter's assertion, the affiliate is a person ''directly involved in . . . purchasing, or selling oil or gas subject to [FOGRMA] through the point of first sale or the point of royalty computation, whichever is later . . .''

(af) Pipeline Residual Return on Investment

Summary of Comments: Many industry comments favored the proposed changes regarding a continued return on investment after a pipeline has been fully depreciated. Companies favored continuing to apply a rate of return against a minimum base value even after the pipeline has been fully depreciated. A few industry commenters were concerned as to how the calculation would be performed if original cost records no longer exist. States expressed concern that allowing a rate of return on some base value after the pipeline is fully depreciated amounts to an unnecessary gift to industry. One citizen also commented that the current regulations should remain, with no additional return on investment allowed beyond the normal life of a pipeline.

MMS Response: MMS believes that, to cover factors such as the ongoing risk of operating a pipeline, it is reasonable to permit a residual return on investment component within the allowance calculation even after the pipeline has been almost completely depreciated. To account for such factors, this final rule, at § 206.111(j), permits the allowance calculation to include an annual return on investment component of ten percent of the total capital investment in the pipeline, even after the pipeline has been depreciated to a level at or below 10 percent of the total capital investment.

Under the final rule, we also added a provision at paragraph (j)(2) clarifying that you may apply this paragraph to a transportation system that before the effective date of the final rule is depreciated to a level at or below a value equal to ten percent of your total capital investment.

(ag) Definitions

Summary of Comments: MMS received many comments that suggested various clarifications and modifications to definitions and terms used throughout the rule. Some groups offered specific suggestions. Others simply asked for additional clarification of some terms. Many comments focused on the definition of ''area'' and asserted that further clarification is warranted. One commenter noted that the rule as proposed would value some crude from the San Juan Basin one way if it were produced from surface wells in New Mexico or Arizona and another way if produced from surface wells in Utah or Colorado. The commenter recommended that the Four Corners area be treated consistently for valuation purposes because all production from the area generally is sold into the same market.

MMS Response: Many of these terms used and defined in this rule were used in the previous rule, and further changes are not necessary. MMS agrees that the terms ''exchange for physicals'' and ''time trades'' can be removed from the definition of exchange agreement, and removed them in this final rule.

MMS believes the defined term ''area'' requires no additional modification. This definition is similar to the definition in the 1988 regulations. Moreover, this rule relies less on ''area'' than the 1988 regulations did.

However, we agree with the commenter who said production from the Four Corners area should be valued consistently. As a result we have modified the Rocky Mountain Region definition to mean the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and, more generally, the ''Four Corners'' area that lie within Colorado and Utah.

(ah) Alleged Illegal Information Transfers for Transportation Allowance Calculations

Summary of Comments: Some producers and industry groups commented that in order for them to calculate ''actual costs'' under the proposed rule, they need pipeline data from their affiliate. These commenters assert that the Interstate Commerce Act (ICA) prohibits the disclosure of this information. Even if this data was available and could be legally disclosed, they say MMS ignores the burden it now places on companies to compute this ''actual cost''.

MMS Response: MMS believes that disclosure of pipeline cost information between affiliates is legal, the information is readily available, and affiliates have the right to exchange information and often do.

The estimate of the cost burden related to calculation of ''actual transportation costs'' is embedded in the cost estimate for completing the Form MMS–2014, on which the allowance is reported, and is discussed in the ''Procedural Matters'' section of this preamble.

(ai) Cushing Spot Prices as a Benchmark in the Rocky Mountain Region

Summary of Comments: A State commented, and some industry groups agreed, that using the Cushing, Oklahoma WTI spot price is not an appropriate measure of value for Wyoming crude oil. There may be only a few trades from Wyoming to Oklahoma, which means an accurate differential may be impossible to obtain.

MMS Response: Valuation of oil produced in the RMR and not sold at arm's length is determined under a series of benchmarks. If the first benchmark does not apply, the lessee may select either the second or the third. The third is the WTI spot price at Cushing, Oklahoma. The lack of a dependable published spot price within the RMR prompted MMS to refer to the Cushing price. If the first two benchmarks cannot be applied, and the lessee believes the use of WTI in the third benchmark is not properly adjustable back to its property in Wyoming, the MMS Director may establish an alternate value under the fourth benchmark.

X. Summary and Discussion of Adopted Rules

This final rule incorporates changes made in response to comments on the January 1997 proposal, the July 1997 proposal, the September 1997 notice, the February 1998 proposal, the July 1998 proposal, the March 1999 notice, and the December 1999 proposal. As in the February 1998 proposal, we also added and renumbered sections and further reorganized the rule for readability.

This summary of adopted rules builds on the above summary of, and MMS's responses to, comments received on the January 1997, July 1997, September 1997, February 1998, July 1998, March 1999, and December 1999 proposals and notices. Because this final rule is a product of changes made in response to comments received throughout this rulemaking, the preambles of each of the previous proposals and notices may be consulted in conjunction with this preamble to trace the evolution of the final rule.

Note that the renumbering and reorganization for the final rule resulted in the following modifications to the existing rule at 30 CFR Subpart C-Federal Oil:

Section	Modification
§§ 206.100 and 206.101	Revised.
§§ 206.102	Revised and redesignated as §§ 206.102, 206.103, 206.104, 206.105, 206.106, 206.107, and 206.108.
§§ 206.103 and 206.104	Redesignated as §§ 206.119 and 206.109, respectively.
§§ 206.105	Revised and redesignated as §§ 206.110, 206.111, 206.114, 206.115, 206.116, 206.117, and 206.118.
§§ 206.106	Revised and redesignated as §§ 206.120.
	New §§ 206.112, 206.113, and 206.121 added.

In addition, we rewrote all sections of the existing rule in plain English so the entire rule would read consistently.

Before proceeding with the summary and discussion of adopted rule, it is appropriate to reiterate the conceptual framework of the final rule. When crude oil is produced, it is either sold at arm's length or is refined without ever being sold at arm's length. If crude oil is exchanged for other crude oil at arm's length, the oil received in the exchange is either sold at arm's length or is refined without ever being sold at arm's length. Under this final rule, oil that ultimately is sold at arm's length before refining generally will be valued based on the gross proceeds accruing to the seller under the arm's-length sale. This includes oil that is exchanged at arm's length where the oil received in exchange is ultimately sold at arm's length. (The exceptions reflect particular circumstances in which MMS believes the arm's-length sale does not or may not reliably reflect the real value.) However, the final rule also provides the option for the lessee to apply index prices or benchmark values because of the difficulty of ''tracing'' production in some exchanges and affiliate resales. If oil (or oil received in exchange) is refined without being sold at arm's length, then the value will be based on appropriate index prices or other methods, as explained below.

These principles apply regardless of whether oil is sold or transferred to one or more affiliates or other persons in non-arm's-length transactions before the arm's-length sale, and regardless of the number of those non-arm's-length transactions. They also apply if an arm's-length exchange occurs before an arm's-length sale. (However, MMS believes that if there are multiple exchanges prior to an arm's-length sale, using the ultimate arm's-length sales price may in some cases require too much ''tracing'' of the oil to be cost-efficient for lessee and lessor alike. Consequently, under such circumstances, MMS has provided the option to determine value based either on the arm's-length gross proceeds or on an index or benchmark basis. The same option is provided for valuing production that is first sold or transferred to an affiliate and then resold at arm's length.)

Lessees and producers may structure their business arrangements however they wish, but MMS generally will look to the ultimate arm's-length disposition in the open market as the best measure of value. This means that MMS will not be ''second-guessing'' industry business decisions. Where a true arm's-length sale occurs that has not been preceded by non-arm's-length exchanges, the gross proceeds from that sale will represent royalty value, absent misconduct on the part of the lessee or breach of express or implied lease covenants, unless the lessee opts to apply index or benchmark values in appropriate situations.

Nor does the express language regarding the lessee's obligation to market production for the mutual benefit of the lessee and the lessor give MMS a license to ''second-guess'' marketing decisions. As discussed above, that obligation has always been an implied covenant of the lease.

Similarly, if oil is refined without being sold at arm's length, MMS believes that the valuation methods prescribed in this final rule are the best measures of value regardless of internal, inter-affiliate, or other non-arm's-length transfers.

Another important feature of the final rule is separate valuation procedures for California and Alaska, the RMR, and the rest of the country. In California and Alaska, if oil is not sold under an arm's-length contract, value would be based on ANS spot prices, adjusted for location and quality. MMS chose this indicator because it believes that ANS is the best measure of market value in that area when oil is not sold at arm's length.

In the RMR, if oil is not sold under an arm's-length contract, market value is more difficult to measure because of the isolated nature of the RMR from the major oil market centers. Therefore, MMS will accept values established by a company-administered tendering program as the first benchmark.

If the company does not have an approved tendering program, it may choose either the second or third benchmark. The second benchmark is a volume-weighted average of the gravity-normalized prices at which the lessee and its affiliates purchase or sell production from both Federal and non-Federal leases in the field or area at arm's length, if those arm's-length sales and purchases exceed 50 percent of the lessee's and its affiliates' production.

The third benchmark is the spot price for WTI crude at Cushing, Oklahoma, with location and quality adjustments. MMS chose the Cushing spot price because no acceptable published spot price exists in the RMR. If none of the first three benchmarks results in a reasonable value, the MMS Director may establish an alternative valuation method.

For other areas of the country, value would be based on the nearest spot price for oil of similar quality to your production, adjusted for quality and location. MMS believes that because the spot market is so active in areas other than the RMR, it is the best indicator of value in those other areas.

Section 206.100 What Is the Purpose of This Subpart?

As proposed in December 1999, this section includes the content of the existing section except for minor wording changes to improve clarity, additional language in new § 206.100(b) clarifying the respective roles of lessees and designees, and additional wording in § 206.100(d)(3) regarding written valuation agreements between the lessee and the MMS Director. (''Lessees'' and ''designees'' are defined in § 206.101, and those definitions follow the definitions contained in Section 3 of the Federal Oil and Gas Royalty Management Act, 30 U.S.C. § 1702, as amended by Section 2 of the Federal Oil and Gas Royalty Simplification and Fairness Act, Pub. L. No. 104–185, 110 Stat. 1700.)

Specifically, if you are a designee and you or your affiliate dispose of production on behalf of a lessee, references to ''you'' and ''your'' in the rule refer to you and not to the lessee. In this event, you must report and pay royalty by applying the rule to your and your affiliate's disposition of the lessee's oil. If you are a designee and you report and pay royalties for a lessee but do not dispose of the lessee's production, the references to ''you'' and ''your'' refer to the lessee and not the designee. In that case, you as a designee would have to determine royalty value and report and pay royalty by applying the rule to the lessee's disposition of its oil. Some examples will illustrate the principle.

Assume that the designee is the unit operator, and that the operator sells all of the production of the respective working interest owners on their behalf and is the designee for each of them. For each of those working interest owners, the operator, as designee, would report and pay royalties on the basis of the operator's disposition of the production. For example, if the operator transferred the oil to its affiliate, who then resold the oil at arm's length, the royalty value would be the gross proceeds accruing to the designee's affiliate in the arm's-length resale under § 206.102, or the appropriate index or benchmark value under § 206.103, as explained further below.

Alternatively, assume the operator is the designee but a lessee disposes of its own production. Assume the lessee transfers its oil to an affiliate, who then resells the oil at arm's length. In this case, the operator would have to obtain the information from the lessee, and report and pay royalties on the basis of the gross proceeds accruing to the lessee's affiliate in the arm's-length resale under § 206.102, or, at the lessee's option, on the basis of the appropriate index or benchmark value under § 206.103.

In some cases, the designee is the purchaser of the oil. Assume the operator disposes of the lessee's oil and that the operator is not affiliated with the designee-purchaser. Because the sale to the designee is an arm's-length transaction, then under § 206.102 the designee would report and pay royalty on the total consideration (the gross proceeds) realized on the sale to the purchaser.

In some cases, a lessee sells its production directly to a designee. (In such cases, the designee frequently is the operator but it does not have to be.) Questions may arise regarding whether such an arrangement is actually a sale or is an arrangement for the designee to dispose of the production on behalf of the lessee. These questions were raised during the January 2000 public workshops.

Several scenarios are possible, and each case will have to be considered on its facts. Nevertheless, there are some indicators MMS will examine in determining whether a designee is disposing of production on behalf of a lessee or is purchasing the production from the lessee. These indicators include but are not limited to the following:

- If a lessee sells to an unaffiliated designee where there is no joint operating agreement and the designee or its affiliate refines the oil rather than selling it, MMS ordinarily would regard this arrangement as an arm's-length sale and accept the price as royalty value.
- If a lessee sells to a co-lessee/designee under a joint operating agreement, MMS ordinarily will regard that arrangement as the designee disposing of production on the lessee's behalf and not as an actual sale to the designee.
- If the price paid to the lessee by the designee is dependent on the designee's receipts on resale of the production (*e.g.*, a specified percentage of the co-lessee's receipts), MMS ordinarily will regard that arrangement as the designee disposing of the production on the lessee's behalf and not as a sale. (In this situation, even if the transaction were regarded as an arm's-length sale, the designee is most likely the lessee's marketing agent in any event. Thus, the difference in price between the designee's receipts and what it pays the lessee would reflect the lessee's marketing costs, which it may not deduct from royalty value.)

We also note that the question of whether a lessee is selling to a designee (as opposed to the designee disposing of production on the lessee's behalf) is related to the larger question of whether a sale to a co-lessee (including one who is not a designee) is an arm's-length sale as opposed to an arrangement where the co-lessee is the lessee's marketing agent. MMS acknowledges that there are many cases in which a lessee sells to a co-lessee (whether a designee or not) at arm's length. But there are also many cases in which a co-lessee effectively acts as the marketing agent for the lessee. We will discuss this question further below in connection with arm's-length sales under § 206.102(a).

Revised § 206.100(a) is the same as the corresponding paragraph in the existing rule, rewritten for clarity. New § 206.100(b) clarifies the respective roles of lessees and designees.

New § 206.100(d) is essentially the same as existing § 206.100(b). That provision says that if any Federal statute, settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or oil and gas lease subject to the requirements of this subpart is inconsistent with any regulation in this subpart, then the statute, lease provision, or settlement agreement governs to the extent of the inconsistency. However, we added a separate provision at new § 206.100(d)(3). It says that if a written agreement between the lessee and the MMS Director establishes a production valuation method for any lease that MMS expects at least would approximate the value otherwise established under this subpart, the written agreement will govern to the extent of any inconsistency with the regulations. This provision is intended to provide flexibility to both MMS and the lessee in those few unusual circumstances where a separate written agreement is reached, while at the same time maintaining the integrity of the regulations. As noted, any such agreement also must at least approximate the royalty value that would apply under these regulations for the production.

The content of new § 206.100(e) is the same as in existing paragraph (c), but rewritten for clarity. It says MMS may audit and adjust all royalty payments.

Section 206.100 also reflects the principle that this rule constitutes the Secretary's exercise of his authority reserved under the statutes and lease terms to establish the reasonable value of production for royalty purposes. MMS will not look to other possible measures of value that may be referenced in the lease terms (for example, the so-called ''major portion'' value) to supersede these rules, except in those few unusual circumstances where MMS and the lessee establish a written royalty valuation agreement under § 206.100(d)(3).

We removed existing paragraph (d). It said the regulations in this subpart are intended to ensure that the United States discharges its trust responsibilities concerning Indian oil and gas leases. Since Indian leases are subject to a separate set of valuation regulations at 30 CFR § 206.50 that include the same language as existing paragraph (d), the existing language at paragraph 206.100(d) is not needed.

Section 206.101 What Definitions Apply to This Subpart?

The definitions section in the final rule remains virtually the same as in the December 1999 proposal. The preamble to that proposal explains thoroughly each of the changes to definitions previously proposed (64 FR at 73825–73827). Several of these definitions also have been discussed at various points earlier in this preamble. The only changes in the final rule to the definitions proposed in December 1999 are:

- *Affiliate*—We changed one detail of the definition proposed in December 1999. That definition said that if there is ownership or common ownership of between 10 and 50 percent of another person, MMS will consider various factors in determining whether control exists. One of those factors involves forms of ownership, including percentage of ownership or common ownership, the relative percentage of such ownership compared to percentages of ownership by other persons, whether a person is the greatest single owner, and whether there is an opposing voting bloc of greater ownership. We changed the *and* preceding the final clause to *or* in the final rule. We did this to avoid the implication that all of the listed factors carry equal weight in all situations or that if one factor does not apply, then none of them does. MMS may consider any one of the factors in subparagraph (2) of the definition to establish control.

- *Exchange agreement*—We have removed the examples included in the December 1999 proposal of exchanges of produced oil for futures contracts (Exchanges for Physical, or EFP) and exchanges of produced oil for similar oil produced in different months (Time Trades) because these trades or exchanges involve different time periods and may not reflect reliable location/quality differentials applicable to royalty payment for a particular production month.
- *Location differential*—We added language clarifying that the amount paid or received as a location differential under an exchange agreement may be expressed in terms of either money or barrels of oil.
- *Quality Differential*—We added language clarifying that the amount paid or received as a quality differential under an exchange agreement may be expressed in terms of either money or barrels of oil.
- *Trading Month*—We added this definition to clarify the changes we made in the final rule regarding the timing and application of spot prices under § 206.103. We also believe use of this term will help in understanding the general concepts of spot price formulation and application. *Trading month* means the span of time during which crude oil trading occurs and spot prices are determined, generally for deliveries of corresponding production in the following month. (We use the term ''generally'' only because for West Texas Intermediate at Cushing, Oklahoma, spot prices are published for deliveries both in the following month and the second-following month.) For Alaska North Slope (ANS) spot prices, the trading month includes the entire calendar month. For other domestic spot prices, the trading month includes the span of time from the 26th of the previous month through the 25th of the current month.

Section 206.102 How do I Calculate Royalty Value for Oil That I or My Affiliate Sell Under an Arm's-Length Contract?

In the December 1999 proposal, we revised and reorganized § 206.102 as written in the several previous proposed rules. We revised § 206.102 to specifically address valuation of oil ultimately sold under arm's-length contracts. We have adopted § 206.102 as proposed in December 1999 with only a few minor changes in wording for clarification.

An arm's-length sale may occur immediately, or may follow one or more non-arm's-length transfers or sales of the oil or one or more arm's-length exchanges.

Paragraph (a) states that value is the gross proceeds accruing to you or your affiliate under an arm's-length contract, less applicable allowances. Similarly, if you sell or transfer your Federal oil production to some other person at less than arm's length, and that person or its affiliate then sells the oil at arm's length, royalty value is the other person's (or its affiliate's) gross proceeds under the arm's-length contract.

For example, a lessee might sell its Federal oil production to a person who is not an ''affiliate'' as defined, but with whom its relationship is not one of ''opposing economic interests'' and therefore is not at arm's length. An illustrative example would be a number of working interest owners in a large field forming a cooperative venture that purchases all of the working interest owners' production and resells the combined volumes to a purchaser at arm's length. Xeno, Inc., 134 IBLA 172 (1995), involved a similar situation for a gas field. If no single working interest owner owned 10 percent or more of the new entity, the new entity would not be an ''affiliate'' of any of them. Nevertheless, the relationship between the new entity and the respective working interest owners would not be at arm's length. In this instance, it would be appropriate to value the production based on the arm's-length sale price the cooperative venture received for the oil.

Paragraph 206.102(a)(3) of the February 1998 proposal was meant to be specific to those cases, such as Xeno, where the transfer is not between affiliates but the sale is not at arm's length because the parties do not have opposing economic interests. However, several commenters could not see the difference between (a)(3) and (a)(2); the latter applied only to sales or transfers to an affiliate who then sells the oil at arm's length. Because the result of both paragraphs would be the same, and to stem this confusion, the December 1999 proposal eliminated previous paragraph (a)(3) and included its intent in revised paragraph (a)(2), which we adopt in the final rule. That paragraph now says value is the gross proceeds accruing to the seller under the arm's-length contract, less applicable allowances, where you sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person or another affiliate of either of them then sells the oil under an arm's-length contract unless you exercise the option provided in paragraph (d)(2) of this section. As a result of this change, paragraph (a)(4) of the February 1998 proposal now becomes § 206.102(c).

In all these circumstances, you must value the production based on the gross proceeds accruing to you, your affiliate, or other person to whom you transferred the oil (or its affiliate) when the oil ultimately was sold at arm's length unless you elect to use index pricing or benchmarks under § 206.102(d).

Because a lessee may sell oil to a co-lessee, questions arise regarding whether a sale to an unaffiliated co-lessee (particularly a co-lessee who is an operator) is an arm's-length sale or is really a marketing arrangement (with the purchasing co-lessee acting as the lessee's marketing agent). As noted in the discussion of § 206.100 above, these questions are closely related to the question of whether a co-lessee who is also a designee is disposing of production on the lessee's behalf or whether it is buying the lessee's production, which was raised in the January 2000 public workshops. MMS acknowledges that there are cases in which a lessee sells to a co-lessee at arm's length and in which the arm's-length sales price is the royalty value. But there are also many cases in which a co-lessee effectively acts as the marketing agent for the lessee.

Possible factual scenarios may vary widely, and each case must be evaluated on its facts. MMS may look to a number of factors. These include, but are not limited to, the following:

- If the purchasing co-lessee or its affiliate refines the oil rather than reselling it, MMS ordinarily will regard the sale as an arm's-length sale.
- If the sales price under the contract with the co-lessee is dependent on the co-lessee's resale receipts, MMS ordinarily will regard the co-lessee as the lessee's marketing agent.
- If the co-lessee disposes of production under a joint operating agreement, MMS ordinarily will regard

the co-lessee as the lessee's marketing agent.

Paragraph (a)(5) of the January 1997 proposal dealt with inclusion in gross proceeds of payments made to reduce or buy down the price of oil to be produced in later periods. We removed this paragraph in the February 1998 proposal but added the concept within the definition of *gross proceeds* as discussed above. This remained unchanged in the December 1999 proposal. The final rule reflects the February 1998 proposal and the December 1999 proposal in this regard without change.

Paragraph (b) clarifies how to value the oil produced from your lease when you sell or transfer it to your affiliate or to another person under a non-arm's-length contract, and your affiliate, the other person, or an affiliate of either of them sells the oil at arm's-length under multiple arm's-length contracts. In this case, value is the volume-weighted average of the values established under paragraph (a) for each contract for the sale of oil produced from that lease.

A number of commenters said that calculating this volume-weighted average value would be extremely problematic because it often would be difficult to tie specific contracts to specific Federal oil production, especially where commingling of various production is involved. MMS acknowledges that proper royalty calculations can be complicated in such situations, but that does not diminish the lessee's duty to pay proper royalties on its Federal production. Even under the existing rules, circumstances similar to those described by the commenters often require that the lessee allocate values and volumes. We believe this provision is consistent with ongoing practice.

Paragraph (c) specifies two exceptions to the use of arm's-length gross proceeds. It also requires you to apply the exceptions to each of your contracts separately.

Paragraphs (c)(1) and (c)(2) remain essentially unchanged from paragraphs (a)(2) and (a)(3) in the January 1997 proposal. Note, however, that paragraph (a)(4)(ii) of the July 1997 proposal said that where an arm's-length contract price does not represent market value because an overall balance between volumes bought and sold is maintained between the buyer and seller, royalty value would be calculated as if the sale were not at arm's length.

In the February 1998 proposal, MMS decided to remove that language as a specific, separate provision. Rather, in considering whether an arm's-length contract reflects your or your affiliates' total consideration or market value (proposed paragraphs (c)(1) and (c)(2)), MMS would examine whether the buyer and seller maintain an overall balance between volumes they bought from and sold to each other. Under these paragraphs, if an overall balance agreement were found to exist, MMS would require you to value your production under § 206.103 or the total consideration received.

Several commenters said that removal of the overall balance provision and relying on MMS to find such agreements put an undue burden on MMS. They further stated that MMS would have great difficulty verifying the existence of such agreements. As explained in the December 1999 proposal, we continue to believe, however, that verification of overall balancing arrangements, and appropriate follow up, is best left to audit in conjunction with the provisions of paragraphs 206.102(c)(1) and (c)(2). There were no comments in response to the December 1999 proposal that added any new informative analysis on this question. Thus, the final rule does not contain any specific language regarding balancing agreements.

Likewise, the final rule does not contain any specific language regarding crude oil calls. In response to the July 1997 and February 1998 proposals and in MMS's public workshops, several commenters asserted that producers often negotiate competitive prices even if a non-competitive call provision exists and a call on production is exercised. We agreed with this point in the December 1999 proposal. In the final rule, oil subject to a noncompetitive crude oil call will be examined in view of paragraphs 206.102(c)(1) and (c)(2) to determine whether the prices received represent market value. The value of oil involved in a noncompetitive crude oil call thus ultimately will be the lessee's total consideration or the value determined by the non-arm's-length methods in § 206.103.

In the July 1997 proposal, MMS modified paragraph (a)(4) of the January 1997 proposal regarding exchange agreements and crude oil calls. It also proposed a new paragraph (a)(6) regarding exchange agreements. See the preamble to the July 1997 proposal at 62 FR 36031 for a complete explanation of the changes proposed. In the February 1998 proposal, we further modified the exchange agreement language at paragraphs (a)(4)(i) and (a)(6) of the July 1997 proposal and combined it in paragraph (c)(3). That paragraph required use of § 206.103 to value oil you dispose of under an exchange agreement. But if you entered into one or more arm's-length exchange agreements, and after these exchanges you or your affiliate disposed of the oil in an arm's-length sale, you would value the oil under paragraph (a) on the basis of the gross proceeds received under the arm's-length contract for the sale of the oil received in exchange. You would adjust the value determined under paragraph (a) for location or quality differentials or any other adjustments you received or paid under the arm's-length exchange agreement(s). However, if MMS found that any such differentials or adjustments weren't reasonable, it could require you to value the oil under § 206.103.

This concept was similar to paragraph (a)(6)(i) of the July 1997 proposal, but with three differences. First, the July 1997 language referred to exchange agreements with a person not affiliated with you. The February 1998 proposal clarified that this covered arm's-length exchange agreements. This meant that not only must you be unaffiliated with your exchange partner, but there must be opposing economic interests regarding the exchange agreement. MMS believed this would limit instances where inappropriate or unreasonable location, quality, or other adjustments would be applied. MMS proposed to limit this provision to arm's-length exchanges because it believed transportation, location, and quality differentials stated in non-arm's-length exchange agreements are not reliable.

Second, MMS clarified that the same valuation procedure would apply if there is more than one arm's-length exchange. For example, if you entered into two sequential arm's-length exchanges for your Federal oil production and then you or an affiliate sold the reacquired oil at arm's length, you would value your production under paragraph (a) under the February 1998 proposal. MMS believed that as long as the integrity of the differentials and adjustments was maintained, there was no reason not to look to the ultimate arm's-length sale proceeds.

Third, under paragraph (a)(6)(i) of the July 1997 proposal, if you disposed of your oil under an exchange agreement with a non-affiliate and after the exchange you sold the acquired oil at arm's length, you could have elected to value your oil either at your gross proceeds or under index pricing. MMS eliminated this option in the February 1998 proposal, believing that the actual arm's-length disposition should govern valuation. That is, the provisions of §§ 206.102 or 206.103 would have been applied according to your actual circumstances. This change also led to the deletion of the previously-proposed paragraph (a)(6)(iii), which related to the election we eliminated in the February 1998 proposal.

As a result of the changes discussed previously, MMS also eliminated paragraph (a)(6)(ii) of the July 1997 proposal. This paragraph would have required you to use index pricing if you either transferred your oil to an affiliate before the exchange occurred, transferred the oil you received in the exchange to an affiliate, or entered into a second exchange for the oil you received back under the first exchange. MMS believes that if you transfer your production to an affiliate and the affiliate then enters into an arm's-length exchange and sells the oil received in the exchange at arm's length, the arm's-length proceeds should be the measure of value. Likewise, if you enter an arm's-length exchange but then transfer the oil received to an affiliate who resells the oil at arm's length, the arm's-length proceeds should be the measure of value. For any exchanges where the oil received in return is not resold but instead is refined, index prices would apply as discussed under § 206.103.

However, we received numerous comments about the problems of tracing value back to the lease where an arm's-length sale follows multiple arm's-length exchanges. Commenters insisted it would be a monumental task for lessees to track, and for MMS to verify, the multiple transactions involved. Further, the problems involved in such "tracing" are aggravated when the necessary records are in the possession of independent third parties who are not affiliates of the lessee.

As a result, in our July 1998 proposal we modified paragraph 206.102(c)(3) of the February 1998 proposal to require valuation under paragraph 206.102(a) only if you enter into a single arm's-length exchange agreement and following that exchange you dispose of the oil in a transaction to which paragraph (a) applies. If you entered into multiple exchanges to dispose of your production, you would have used § 206.103 to value that production. However, some commenters on the July 1998 proposal believed they also should be able to use their arm's-length gross proceeds following multiple arm's-length exchanges.

Therefore, the December 1999 proposal, at paragraph 206.102(d)(1), provided the option, where arm's-length sales follow one or more arm's-length exchanges, to apply either the arm's-length gross proceeds or the index or benchmark value appropriate to the region of production. To prevent potential abuses of this option, paragraph 206.102(d)(1)(ii) provides that you must apply the option you select for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) sold at arm's length following arm's-length exchange agreements. You may not change this election more often than once every 2 years. We believe this process achieves the best balance of valuing production based on arm's-length gross proceeds and minimizing the administrative problems for all involved, and have adopted it in the final rule.

We reiterate that you must use § 206.103 to value oil disposed of under an arm's-length contract following one or more non-arm's-length exchanges. MMS does not believe it is appropriate to use the terms of non-arm's-length exchange agreements to adjust the arm's-length gross proceeds because the differentials in such agreements may not accurately reflect market rates.

Paragraph (d)(2) of this final rule was proposed in December 1999, and results from comments received throughout the rulemaking process. Some commenters believe that where lessees sell or transfer production to an affiliate and the affiliate resells the oil at arm's length, they should be able to apply an alternative valuation method other than tracing the production to its final disposition. In the final rule, similar to the option for sales following arm's-length exchange agreements, we provide the option to use either the ultimate arm's-length gross proceeds or the appropriate index or benchmark value. Also, paragraph (d)(2)(ii) states that you must apply the option you select for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) disposed of through affiliate resales at arm's length. You may not change this election more often than once every 2 years. Again, we believe this achieves the best balance of valuing production based on arm's-length gross proceeds and limiting administrative burdens.

Paragraph (e) is the same as the December 1999 proposal, and is essentially the same as paragraphs (b)(2) and (3) of § 206.102 in the January 1997 proposal and paragraphs (d)(2) and (3) of the February 1998 proposal and comes directly from existing § 206.102. We have eliminated proposed paragraph (b)(1) of the January 1997 proposal (paragraph (d)(1) of the February 1998 proposal) in connection with the change to the definition of "affiliate" explained previously in this preamble. Also, since this final rule generally requires arm's-length gross proceeds as royalty value regardless of whether the lessee, an affiliate, or another person to whom the lessee has sold or transferred production under a non-arm's-length contract is the person who ultimately sells at arm's length, all of these persons come within the term "seller."

Section 206.103 How Do I Value Oil That I Cannot Value Under § 206.102?

In the February 1998 proposal, this section replaced paragraph 206.102(c) of the January 1997 proposal. The December 1999 proposal included a few changes to this section. The final rule makes a few further changes in this section as explained below.

This section deals specifically with valuation of oil you cannot value under § 206.102 because the oil is not ultimately sold at arm's length or is otherwise excepted under § 206.102. It also applies where you have elected one of the options available at § 206.102(d)(1) or (2).

The February 1998 proposal made a change (continued in the December 1999 proposal) from the January 1997 proposal for value based on index prices. In MMS's initial proposal, where either NYMEX or spot prices were applied in valuation, the prices for the month following the lease production month were used. This was meant to reflect the fact that spot prices and NYMEX futures prices for the following month are determined during the month of production. MMS believed this best reflected market value at the time of production. However, various commenters asserted that, for application of spot or futures prices, the lease production month should coincide with the spot or futures delivery month. They said this would effectively match production to index prices for deliveries in the same month. In the February 1998 and December 1999 proposals, we accordingly changed the timing of application of index prices so that the lease production month and the spot delivery month would coincide.

However, as explained above, further examination has led us to believe that in some cases the use of spot prices determined before the production month could affect lessees' production decisions and, ultimately, royalties paid. See Section VI(e) above. For the reasons stated there, the final rule applies the spot price effectively determined during the production month so that price determination is concurrent with production.

Also, paragraph 206.102(c)(1) of the January 1997 proposal would have permitted you an option if you first transferred your oil production to an affiliate and that affiliate or another affiliate disposed of the oil under an arm's-length contract. The option was to value your oil at either the gross proceeds accruing to your affiliate under its arm's-length contract or the appropriate index price. For the reasons discussed earlier, we have reinserted that option in this final rule under paragraph 206.102(d)(2). MMS believes that where arm's-length transactions satisfying the provisions of § 206.102 occur, royalty value generally should be the arm's-length gross proceeds. However, providing this option should afford some administrative relief to lessors while assuring receipt of fair royalty values.

Another change from the January 1997 proposal is an additional geographic breakdown for valuation purposes. The original proposed rule included separate valuation procedures for California and Alaska separately from the rest of the country. But based on the various written comments MMS received in response to its January 1997, July 1997, September 1997, February 1998, July 1998, March 1999, and December 1999 proposals and notices, and comments made at the various valuation workshops and hearings, it became apparent that oil marketing and valuation in the RMR is significantly different from other areas. Also, the only published spot price in the RMR is at Guernsey, Wyoming. Most commenters consistently maintained that the spot price there is based on thinly-traded volumes. The combination of geographical remoteness from midcontinent markets, unique marketing situations, and the lack of a meaningful published spot price led MMS to add the RMR as a third royalty valuation region.

Paragraph 206.103(a) applies to production from leases in California or Alaska. It replaces paragraph 206.102(c)(2)(ii) of the January 1997 proposal and includes a change from the December 1999 proposal. Under the final rule, value is the average of the daily mean ANS spot prices, published in any MMS-approved publication, that apply to the month following the production month (instead of those published during the calendar month preceding the production month). You must adjust the value for applicable location and quality differentials, and you may adjust the value for transportation costs, as described at § 206.112. The only change in this final rule is a more detailed explanation of how to calculate the spot prices.

To calculate the daily mean spot prices, average the published daily high and low prices published during the production month, only using the days and corresponding prices for which spot prices are published. Do not include weekends, holidays, or any other days when spot prices are not published. For example, assume the production month has 31 days, including 8 weekend days and a holiday, and the publication publishes spot prices for all other days. You would average together the published high and low spot prices for each of the 22 remaining days.

An example of the index pricing method utilizing ANS spot prices for California production follows. Assume that the production month is December 1999 and that we take data from an MMS-approved publication. To reflect the market's assessment of value during the production month, use the spot prices published during December 1999 (for the January 2000 spot sales delivery month). The daily mean spot price assessments during December 1999 are averaged to arrive at the ANS price basis, in this case $24.5469 per barrel. This price would be adjusted for location/quality differentials and transportation (as discussed elsewhere in this preamble) in determining the proper value of your oil. The following table illustrates the calculation in this example:

ALASKA NORTH SLOPE SPOT PRICES—DECEMBER 1999

[Prices for January 2000 Delivery, December 1999 Production]

Date	Low ($/bbl)	High($/bbl)	Average
12/01/99	23.3300	23.4000	23.3650
12/02/99	24.0500	24.1200	24.0850
12/03/99	24.0900	24.1500	24.1200
12/06/99	24.9500	25.0600	25.0050
12/07/99	24.6000	24.6800	24.6400
12/08/99	24.9000	24.9500	24.9250
12/09/99	24.6000	24.6500	24.6250
12/10/99	23.9500	24.0100	23.9800
12/13/99	23.8500	23.9100	23.8800
12/14/99	24.3300	24.4000	24.3650
12/15/99	24.8300	24.9100	24.8700
12/16/99	25.3500	25.4100	25.3800
12/17/99	25.2500	25.2800	25.2650
12/20/99	24.9000	25.0300	24.9650
12/21/99	24.7100	24.7500	24.7300
12/22/99	23.9400	24.0000	23.9700
12/23/99	24.4100	24.4400	24.4250
12/27/99	24.7500	24.8400	24.7950
12/28/99	25.2400	25.3100	25.2750
12/29/99	24.6000	24.6500	24.6250
12/30/99	24.1700	24.2200	24.1950
Average	24.5143	24.5795	24.5469

We received various comments about use of ANS spot prices. Most industry commenters said that because there are significant differences between ANS and California crudes in terms of quality, product yield, transportation modes and distances, and timing of production versus delivery, the ANS spot price is not a good value indicator for California crude oil production. The State of California and City of Long Beach, on the other hand, continue to endorse the use of ANS spot prices. They indicate that ANS spot prices are used in many arm's-length transactions and that ANS crude constitutes a large percentage of California refinery feedstock. MMS's own experience, including participation in the interagency task force investigating California oil undervaluation, shows that ANS crude frequently has been used by industry as a valuation benchmark for valuing California crudes. Also, because of the control of the pipeline transportation network in California by a few companies who also act as purchasers of a large portion of California crude oil production, the use of posted prices or contracts based on postings as a basis for valuing crude disposed of at other than arm's-length is questionable. We believe that, with proper adjustments for location and quality differences, the ANS spot price is the best available measure of royalty value for Federal oil production in California that is not sold at arm's length.

MMS has received comments to the effect that a court decision in favor of Exxon in California demonstrates that adjusted ANS prices do not reflect reasonable values for California crude oil. MMS disagrees because the facts in the Exxon case are different and the leases involved are not Federal leases.

The State of California and the City of Long Beach first sued Exxon in the mid-1970s alleging that Exxon (along with other major producers) had conspired to keep posted prices low and that the State and City had been damaged because their oil revenues depended on posted prices. The contracts with the City required oil value at the higher of posted prices or prices paid at Wilmington or three nearby fields. The City and State contended that true value was higher and should be tied to ANS prices. The State and City ultimately took the case against Exxon to a jury trial before the Los Angeles County Superior Court on a breach-of-contract claim. On August 30, 1999, the jury found that Exxon did not act in bad faith or manipulate prices for oil produced from the Wilmington field from 1981–1989, and had conformed to its contract requirements.

A jury verdict does not constitute a legal ruling on Federal leases or on Federal royalty issues. The contract terms were very specifically tied to posted prices or prices received in the immediate area. Federal oil leases require royalty payments based on different principles than those used by the jury. Rather than a contract price agreed on in advance, Federal oil royalties are tied to regulations that require different valuation procedures depending on how the oil is sold.

The lands at issue in the Exxon case were State-owned and not leased. The companies participating in their development bought most of the oil produced. This situation is much different from a Federal lessee paying a royalty on the value of production. For all of these reasons, the Exxon State court decision has no applicability here.

Paragraph 206.103(b) applies to production from leases in the Rocky Mountain Region, a defined term. As discussed above, production in the RMR is controlled by relatively few companies, and the number of buyers is more limited than in the Texas, Gulf Coast, or Midcontinent areas. As a result, there is less spot market activity and trading in this area due to the control over production and refining. The majority of written comments we received, as well as oral comments in our public meetings, agreed that a separate valuation procedure is needed for the RMR.

As noted above, all of the previous proposals defined the Rocky Mountain Region as the States of Wyoming, Montana, North Dakota, South Dakota, Colorado, and Utah. However, portions of southern Colorado and southern Utah encompass parts of the San Juan Basin and, more generally, the ''Four Corners'' area. (The ''Four Corners'' is the convergence of the boundaries of New Mexico, Arizona, Utah, and Colorado.) New Mexico and Arizona are not part of the RMR. Parts of the San Juan Basin and the Four Corners area are within the boundaries of those States. Oil produced from the San Juan Basin and the Four Corners area typically is sold or exchanged to midcontinent markets (such as Midland, Texas), where dependable spot prices are published.

One commenter on the December 1999 proposal noted that the rule as proposed would value some crude from the San Juan Basin one way if it were produced from surface wells in New Mexico or Arizona and another way if produced from surface wells in Utah or Colorado. The commenter recommended that the Four Corners area be treated consistently for valuation purposes because all production from the area generally is sold into the same market.

There was no logical reason to treat those portions of the San Juan Basin or the Four Corners area that lie within Colorado or Utah any differently than those parts that lie within New Mexico or Arizona. Accordingly, we have excluded them from the definition of Rocky Mountain Region. Consequently, you must value oil produced from leases in these areas under the standards applicable to the remainder of the country.

For the reasons explained above, we derived a series of valuation benchmarks for the RMR. The final rule makes one change from the December 1999 proposal, as discussed below.

The first benchmark applies if you have an MMS-approved tendering program (a defined term). The value of production from leases in the area the tendering program covers is the highest price bid for tendered volumes. Under your tendering program you must offer and sell at least 30 percent of your production from both Federal and non-Federal leases in that area. You also must receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

MMS added the several qualifications stated above to ensure receipt of market value under tendering programs. First, royalty value must be the highest winning bid price rather than some other individual or average value. Several commenters said this is inappropriate because it is possible that a single bidder may only bid on some small portion of the tendered volumes at a high price, but this price would then apply to all tendered volumes. We continue to believe, however, that to assure receipt of market value, value must be based on the highest winning bid received.

Second, you must offer and sell at least 30 percent of your production from both Federal and non-Federal leases in that area. The rationale for this minimum percentage is to ensure that the lessee puts a sufficient volume of its own production share up for bid to minimize the possibility that it could abuse the system for Federal royalty or State tax payment purposes. MMS originally chose 33⅓ percent as the minimum because it exceeded the typical combined Federal royalty rate and effective composite State tax and royalty rates for onshore oil leases by roughly 10 percent. We received various comments that this figure was too high and that it was not appropriate to consider State royalties, since they would not be payable on Federal leases. MMS recognizes this fact but also notes that for the oil-producing States in the RMR the combined Federal royalty rate and State composite effective tax rate on Federal oil production typically ranges from about 17 percent to about 27 percent. These percentages do not include State royalty rates. In the December 1999 proposal, we therefore chose 30 percent, or just above the high end of the royalty/tax range, as the minimum percentage the lessee would have to tender for sale to assure that some of the lessee's equity share of production generally was involved. Likewise, the tendering program would be required to include non-Federal lease production volumes in the 30 percent determination to ensure that the program isn't aimed at limiting Federal royalty value. Nothing in the comments in response to the December 1999 proposal persuasively rebutted this analysis. We have adopted the December 1999 proposal in the final rule.

Third, to ensure receipt of competitive bids, your tendering program must result in at least three bids from bidders who do not have their own tendering programs covering some or all of the same area. MMS believes that requiring a minimum number of bidders is needed to ensure receipt of market value. In our February 1998 proposal we stipulated a minimum of three bids. However, we received several comments that requiring three bidders was too stringent and that in many cases there simply would not be that many qualified bidders. The December 1999 proposal reviewed this criterion, and maintained the view that a minimum number of bidders is essential to ensure receipt of market value. We believe that at least three bidders are needed and have retained this provision in the final rule. (A lessee may receive more bids, including from bidders who have tendering programs of their own, but at least three bids must be from bidders who do not have their own tendering programs.) Further, MMS is concerned about the possibility of cross-bidding between companies at below-market prices, which could otherwise satisfy the minimum number of bidders requirement. That is why we have retained the stipulation that three bids must come from bidders who do not also have their own tendering programs in the area.

Under the final rule, if the first benchmark (an approved tendering program) does not apply, you may choose between the second and third benchmarks. In the February 1998 and December 1999 proposals, the benchmarks were strictly hierarchical. We have changed to permitting a choice between the second and third benchmarks in response to comments received in the January 2000 public workshops. However, consistent with other options provided in the final rule, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that you cannot value under § 206.102 or that you elect under § 206.102(d) to value under this section. After you select either paragraph (2) or (3), you may not change to the other method more often than every 2 years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new 2-year period.

Under the second benchmark, value is the volume-weighted average gross proceeds accruing to the seller under your and your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month. The benchmark itself is not changed from the December 1999 proposal. The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliates' production from both Federal and non-Federal leases in the same field or area during that month.

MMS developed this method as one alternative if you do not have an approved tendering program, and as an effort to establish value based on actual transactions by the lessee and its affiliate(s). We received a number of comments during the rulemaking process that MMS should look not only to sales by the lessee, but also purchases a lessee and its affiliates make in the field or area. Just as for the tendering program, MMS believes a floor percentage of the lessee's and its affiliates' production should be set to prevent any abuse. Although we received several comments that the 50 percent minimum figure is too high, it is not intended to be a more stringent standard than the 30 percent floor associated with the tendering program. As we explained in the December 1999 proposal, that is because the 50 percent floor applies to the lessee's and its affiliates' sales and purchases in the field or area, rather than just sales as in the tendering program. For example, Company A produces 10,000 barrels of crude oil in a given field during the production month. It sells 1,000 barrels under an arm's-length contract. Company A also has a refining affiliate, Company B, that purchases the remaining 9,000 barrels of Company A's production and 5,000 barrels of oil under arm's-length purchase contracts with other producers in the same field. Together the arm's-length sales by Company A and the arm's-length purchases by Company B are 6,000 barrels, or 60 percent of the lessee's and its affiliates' production in the field that month. The volume-weighted arm's-length gross proceeds accruing to Company A and paid by Company B for these 6,000 barrels represents royalty value for the 9,000 barrels of Company A's Federal lease production in the field that cannot be valued under § 206.102.

This final rule requires using the unadjusted volume-weighted average gross proceeds accruing to the seller in all of the lessee's and its affiliates' arm's-length sales or purchases, not just those that may be considered comparable by quality or volume. We received several comments that this would result in improper valuation of some oil that was significantly different in quality than that associated with the "average" oil. As explained in the December 1999 proposal, we believe that production in the same field or area generally will be similar in quality. However, in the final rule, based on comments received in the January 2000 workshops, we have included a requirement that before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliate's arms-length purchases or sales to the same gravity as that of the oil produced from the lease. Further, given that these sales and purchases must be greater than 50 percent of all of the lessee's production in the field or area, we believe that it is not necessary to distinguish comparable-volume contracts.

MMS received several industry comments that the proposed rule would cause hardships for producers who have marketing, but not refining, affiliates. The marketing affiliate takes the producing affiliate's production and also buys production from various other sources before reselling or otherwise disposing of the combined volumes. Section 206.102 of the February 1998 proposal would have required the producer to base royalty value on its marketing affiliate's various arm's-length sales and allocate the proper values back to the Federal lease production. Many commenters said this "tracing" would be difficult at best, but others wanted the opportunity to do so. One commenter suggested that as an alternative the lessee should be permitted to base the value of its production on the prices its marketing affiliate pays for crude oil it buys at arm's length in the same field or area.

As explained in the December 1999 proposal, we do not agree with this proposal because an overriding general premise of this rulemaking is that where oil ultimately is sold at arm's length before refining, it will be valued based on the gross proceeds accruing to the seller under the arm's-length sale (with the option to use index or benchmark values under some circumstances as discussed earlier). This means the marketing affiliate's arm's-length resale should form the basis for valuing the producing affiliate's production. To do otherwise would be inconsistent with the way arm's-length resales are treated elsewhere in this rule.

The third benchmark value is the average of the daily mean spot prices published in any MMS-approved publication for WTI crude at Cushing, Oklahoma, applicable to deliveries during the month following the production month. You must calculate the daily mean spot price by averaging the daily high and low prices for the month in the selected publication. Use only the days and corresponding spot prices for which such prices are published. You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 206.112 of this subpart. An illustration of how the spot price value is calculated is given below in the discussion of spot price values for areas other than California and Alaska and the RMR.

This paragraph is very similar to paragraph 206.102(c)(2)(i) of the January 1997 proposal. The main difference is that rather than using NYMEX futures prices, we apply Cushing spot prices in the final rule. This was due to an industry comment that since Cushing spot and NYMEX futures prices track closely over time and that we use spot prices in the other two valuation regions, using the spot price in the RMR would lend consistency with no downside effects. As noted earlier, in the final rule we correlated the spot price determination period with the trade month, rather than the delivery month. As provided in the previous proposals, the final rule provides that if you demonstrate to MMS's satisfaction that paragraphs (b)(1) through (b)(3) result in an unreasonable value for your production as a result of circumstances regarding that production, the MMS Director may establish an alternative valuation method.

This method is the last alternative and is intended to be used only in very limited and highly unusual circumstances. We believe there should be very few such alternative valuation methods.

We received several comments that this option should be offered nationwide. However, as we explained in the December 1999 proposal, we believe this is inappropriate because valid spot prices for which reasonable location and quality adjustments may be made are available throughout the rest of the country. While the Cushing spot price likewise is valid, the remoteness of the RMR may in some cases cause such severe difficulties in making reasonable location/quality adjustments that an alternative method may be warranted.

Paragraph 206.103(c) applies to production from leases not located in California, Alaska, or the RMR. As proposed in December 1999, MMS has modified paragraph 206.102(c)(2)(i) of the January 1997 proposal that applied to locations other than California and Alaska. That paragraph would have required you to value your oil at the average daily NYMEX futures settle prices. In this final rule, value is the average of the daily mean spot prices:

(1) For the market center nearest your lease where spot prices for crude oil similar in quality to that of your production are published in an MMS-approved publication. (There may be cases where the nearest market center may not be the appropriate one for you to use because the quality of your production better matches that typically traded at another, more distant market center. In such cases, you may use this alternate market center to value your production.);

(2) For that similar quality crude oil. (For example, at the St. James, Louisiana, market center, spot prices are published for both Light Louisiana Sweet and Eugene Island crude oils. Their quality specifications differ significantly, and you must use the spot price for the oil that is most similar to your production.); and

(3) That are applicable to the month following the production month.

An example of the index pricing method utilizing Empire, Louisiana spot prices for Heavy Louisiana Sweet production follows. Assume that the production month is December 1999 and that we take data from an MMS-approved publication. To reflect the market's assessment of value during the production month, use the spot price published for each business day beginning with November 26, 1999, and ending with December 25, 1999 (for the January 2000 spot sales delivery month). The daily mean spot price assessments during the period November 26, 1999—December 25, 1999 are averaged to arrive at the Empire spot price basis, in this case $26.3089 per barrel. This price would be adjusted for location/quality differentials and transportation (as discussed elsewhere in this preamble) in determining the proper value of your oil for December 1999 production. The following table illustrates the calculation in this example:

HEAVY LOUISIANA SWEET (EMPIRE, LOUISIANA) SPOT PRICES.—DECEMBER 1999

[Prices for January 2000 Delivery, December 1999 Production]

Date	Low ($/bbl)	High($/bbl)	Average
11/29/99	26.2000	26.2400	26.2200
11/30/99	25.0400	25.0900	25.0650
12/01/99	25.4400	25.4800	25.4600
12/02/99	26.2000	26.3000	26.2500
12/03/99	26.5500	26.6000	26.5750
12/06/99	27.5000	27.5200	27.5100
12/07/99	26.9500	27.0000	26.9750
12/08/99	27.2000	27.2500	27.2250
12/09/99	26.7500	26.7900	26.7700
12/10/99	25.9000	26.0300	25.9650
12/13/99	25.7700	25.8000	25.7850
12/14/99	26.2000	26.2500	26.2250
12/15/99	26.8000	26.9500	26.8750
12/16/99	27.2500	27.3300	27.2900
12/17/99	26.3900	26.4500	26.4200
12/20/99	25.9000	26.0200	25.9600
12/21/99	25.7500	25.8500	25.8000
12/22/99	25.5000	25.5500	25.5250
12/23/99	25.9500	26.0000	25.9750
Average	26.2758	26.3421	26.3089

At the January 2000 workshops, one commenter suggested that MMS offer an option to use the market center where exchanges of the lessee's oil typically take place, rather than the market center nearest the lease. As explained above, we have not adopted this suggestion because our intent is to correlate both proximity to the lease and quality similarity. The commenter's suggestion would introduce unwarranted ambiguity and susceptibility to manipulation into the rule.

You must calculate the daily mean spot price by averaging the daily high and low prices for the month in the selected publication. You must use only the days and corresponding spot prices for which such prices are published. You *must* adjust the value for applicable location and quality differentials, and you *may* adjust it for transportation costs, under § 206.112 of this subpart.

As explained in the December 1999 proposal, MMS changed the valuation procedure to use spot, rather than NYMEX, prices, for several reasons. First, we believe that when the NYMEX futures price, properly adjusted for location and quality differences, is compared to spot prices, it nearly duplicates those spot prices. Second, application of spot prices removes one portion of the necessary adjustments to the NYMEX price—the leg between Cushing, Oklahoma, and the market center location. Although industry continued to object to any form of valuation that begins with values away from the lease, we received several comments that using the spot price rather than NYMEX futures prices would improve administration of the rule with no apparent adverse effects.

MMS did not adopt any of the alternatives here (or for California and Alaska) that it did for the RMR where oil cannot be valued under § 206.102. That is because, unlike the RMR, there are meaningful published spot prices applicable to production in the other regions (Cushing, Oklahoma; St. James, Louisiana; Empire, Louisiana; Midland, Texas; Los Angeles/San Francisco, California). In the United States, with the exception of the RMR, spot and related index-type prices drive the manner in which crude oil is bought and traded. Spot prices play a significant role in crude oil marketing. They form a basis on which deals are negotiated and priced and are readily available to lessees via price reporting services. We believe spot prices are the best indicator of value for production from leases outside the RMR. Therefore, it is not necessary to consider other, less accurate means of valuing production not sold at arm's length for regions outside the Rocky Mountains.

We received numerous comments about MMS inappropriately moving the value of production away from the lease without permitting deduction of marketing costs or the value added by the lessee and its affiliates. MMS is not allowing the costs of marketing production as a deduction from value based on index prices or value based on gross proceeds. The requirement to market production for the mutual benefit of the lessee and the lessor at no cost to the lessor is an implied covenant of the lease, and is not unique to Federal leases. *See* Section III(i) for more detail. With respect to the costs of putting production into marketable condition, see, *e.g., Mesa Operating Limited Partnership* v. *Department of the Interior,* 931 F.2d 318 (5th Cir. 1991), cert. denied, 502 U.S. 1058 (1992); *Texaco, Inc.* v. *Quarterman,* Civil No. 96-CV–08-J (D. Wyo. 1997). It follows that any payments the lessee receives for performing such services are part of the value of the production and are royalty bearing. MMS is not altering this principle in this final rule. The rule, in § 206.106 discussed below, simply makes the longstanding implied obligation express.

Paragraph 206.103(d) is paragraph 206.102(c)(3) of the January 1997 proposal with minor clarifying word changes proposed in December 1999. It states that if MMS determines that any of the index (spot) prices are no longer available or no longer represent reasonable royalty value, then MMS will exercise the Secretary's authority to establish value based on other relevant matters. These could include, for example, well-established market basket price formulas.

Paragraph 206.103(e) addresses situations where you transport your oil directly to your or your affiliate's refinery and believe that use of a particular index price is unreasonable. In that event, you may apply to the MMS Director for approval to use a value representing the market at the refinery. Based on the lack of persuasive contrary comments on this provision, which was included in the February 1998 proposal, we included it in the December 1999 proposal and in this final rule with only minor clarifying changes.

Section 206.104 What Index Price Publications Are Acceptable to MMS?

Section 206.104 in the December 1999 proposal and in the final rule is paragraphs (c)(4), (c)(5), and (c)(6) of § 206.102 from the January 1997 proposal with an added reference to spot prices for crude oil other than ANS. The few comments that MMS received on this section simply said that industry should have some input into which publications MMS accepts. We have included this section in this final rule unchanged. MMS will consult with industry groups as appropriate in deciding which publications should be used for index pricing.

Section 206.105 What Records Must I Keep To Support My Calculations of Value Under This Subpart?

Section 206.105 specifies that you must be able to show how you calculated the value you reported, including all adjustments. This is important because if you are unable to demonstrate on audit how you calculated the value you reported to MMS, you could be subjected to sanctions for false reporting.

Section 206.106 What Are My Responsibilities To Place Production Into Marketable Condition and To Market Production?

Section 206.106 is paragraph 206.102(e)(1) of the January 1997 proposal with minor clarifying word changes proposed in December 1999. It says you must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government unless otherwise provided in the lease agreement. As explained previously, we received many comments from industry that MMS is inappropriately trying to force industry to bear all marketing costs and that MMS should share in these costs. MMS disagrees with those arguments and is not altering the lessee's obligation to market production at no cost to the lessor in this final rule.

The January 1997 proposal also included, at paragraph 206.102(e)(2), a provision regarding the lessee's general responsibility to pay interest if the lessee reports value improperly and underpays royalties, or to take a credit for overpaid royalties. We deleted this provision in the December 1999 proposal and have left it out of the final rule because these matters are already covered in other parts of MMS's regulations.

Section 206.107 How Do I Request a Value Determination?

Section 206.107 of the February 1998 proposal included the substance of paragraph 206.102(f) of the January 1997 proposal in shortened and simplified terms. It said you may ask MMS for guidance in determining value, and you may propose a valuation method to

MMS. MMS would then review your proposal and provide you with a non-binding determination of the guidance you request. We received a variety of comments that guidance alone is insufficient and that something much more substantial is needed to provide certainty and protection in case of audit.

The final rule provides for value determinations issued by the Assistant Secretary for Land and Minerals Management that are binding on the lessee and MMS. It also provides for value determinations issued by MMS that are binding on MMS only and not the lessee, and that are not administratively appealable. See MMS's response to comments on the earlier proposals in Sections VI(f), VII(f), VIII(b), and IX(p) above.

Also, we deleted paragraph 206.102(g) of the January 1997 proposal. It discussed audit procedures related to value determinations, and these are covered sufficiently in other parts of MMS's regulations.

Section 206.108 Does MMS Protect Information I Provide?

Section 206.108 is paragraph 206.102(h) of the January 1997 proposal, but with minor wording changes for clarity that we proposed in December 1999.

Section 206.109 When May I Take a Transportation Allowance in Determining Value?

Section 206.109 includes the substance of § 206.104 of the January 1997 proposal with only minor wording changes proposed in December 1999. In the December 1999 proposal and in this final rule, we removed the last two sentences of paragraph (a) of the January 1997 proposal regarding transportation of oil that MMS takes as royalty in kind. These provisions were unnecessary because this issue is addressed in the royalty-in-kind regulations in § 208.8.

This section also includes the provision that you may not take a transportation allowance greater than 50 percent of the value of the oil determined under this subpart. We received several comments that MMS should relax this limitation. However, paragraph 206.109(c)(2) continues the existing practice that you may ask MMS to approve a larger transportation allowance by demonstrating that your reasonable, actual, and necessary costs exceed the 50 percent limitation.

Sections 2206.110 and 206.111 How Do I Determine a Transportation Allowance Under an Arm's-Length Transportation Contract, and How Do I Determine a Transportation Allowance Under a Non-Arm's-Length Transportation Contract?

Sections 206.110 and 206.111 of the December 1999 proposal were paragraphs 206.105(a) and (b), respectively, of the existing rule, rewritten to reflect plain English, with three proposed changes. MMS also requested comments on two other issues. Based on comments received and further analysis, we are making further changes in the final rule.

The December 1999 proposal included two changes to the calculation of actual transportation costs under § 206.111(g). First, under the current regulations, a change in ownership does not alter the depreciation schedule. That is, a transportation system cannot be depreciated more than once by one or more owners. Section 206.111(g)(2) proposed in December 1999 stated that an arm's-length change in ownership of a transportation system would result in a new depreciation schedule for purposes of the allowance calculation. Under the proposed provision, if you or your affiliate purchased an existing transportation system at arm's length, your initial capital investment would have been equal to your purchase price of the transportation system.

The final rule does not adopt the provision as proposed in December 1999. As written, the December 1999 proposal gave rise to serious difficulties because of potential inflated allowances due to the original owner's ability to recover or ''recapture'' its actual costs by selling the pipeline at a value greater than the depreciable balance.

For example, assume that an original owner had paid $20 million to construct a pipeline. Further assume that the original owner used a 20-year straight-line depreciation and made no subsequent reinvestment. Further assume that in year 15, the original owner sold the pipeline at arm's length for $10 million to another person who also transported oil through the pipeline under a non-arm's-length arrangement. Under the December 1999 proposal, the purchaser would have begun a new depreciation schedule based on the $10 million purchase price. But the consequence of this transaction is that the original owner's actual transportation costs effectively were reduced because it recovered $5 million of the $15 million it had taken as depreciation. Thus, if the actual transportation costs it originally reported were not recalculated, more transportation costs than were actually incurred would be deducted from royalty value.

The December 1999 proposal thus gave rise to serious questions of how to ''recapture'' the royalties owed as a result of the reduced costs. One possible solution would have been to require the lessee who sold the transportation system to recalculate all of its transportation allowances for a retrospective period of several years. That would have been an extraordinarily complex calculation, because the difference between the transportation costs reported and the costs actually incurred is not equal to the amount of depreciation the selling lessee recaptured. If the depreciation element of the cost calculation were reduced retroactively, that also would change the calculation of return on undepreciated investment. Thus, the selling lessee would have to recalculate both elements of actual transportation costs for every report month. Further, this recalculation in most cases would involve a number of leases.

In view of the complex and costly burdens that would be imposed on lessees, MMS has not provided for a detailed ''recapture'' procedure in the final rule. Instead, MMS adopted a simpler approach that still addresses much of the concern that led to the provision in the December 1999 proposal.

Under the final rule, if you or your affiliate own a transportation system on the effective date of the rule, you must base your depreciation schedule used in calculating actual transportation costs for royalties paid on production after the effective date of the rule on your total capital investment in the system. Total capital investment includes your original purchase price or construction cost and any subsequent reinvestment.

If you or your affiliate were not the original owner of the system, but purchased the transportation system at arm's length before the effective date of the final rule, you must incorporate depreciation on the schedule based on your purchase price (and subsequent reinvestment) into your transportation allowance calculations in paying royalty on production after the effective date of the rule. However, you would begin at the point on the depreciation schedule corresponding to the effective date of the rule. You must prorate your depreciation for the year 2000 by claiming part-year depreciation for the period from the effective date of the rule until December 31, 2000.

Under this provision, you may not adjust your transportation costs for royalties paid on production before the effective date of the rule using the depreciation schedule based on your purchase price. The final rule does not permit recalculation of allowances for prior periods on that basis. Your calculation of actual transportation costs for periods before the effective date of the rule presumably was based on the original owner's depreciation schedule, and that will remain unchanged.

For example, if you purchased a system at arm's length on January 1, 1995, you would be in the sixth year of the depreciation schedule based on your purchase price. Assume that you had no subsequent reinvestment. You would incorporate into your calculation of actual transportation costs the depreciation applicable to the sixth year from the schedule based on your purchase price. However, you must prorate your claimed depreciation for calendar year 2000 by claiming part-year depreciation for the period from the effective date of the rule until December 31, 2000. If your calculation of actual transportation costs for the period before the effective date of the rule was based on the original owner's depreciation schedule, you may not adjust the calculation of costs for the period before the effective date of the rule using the schedule based on your purchase price.

Under the final rule, if you are the original owner of the transportation system on the effective date of this rule, you must continue to use your existing depreciation schedule in calculating actual transportation costs for production in periods after the effective date of this section. In other words, your depreciation calculation does not change.

However, if you or your affiliate purchase a transportation system at arm's length from the original owner after the effective date of the rule, you thereafter must base your depreciation schedule used in calculating actual transportation costs on your total capital investment in the system (including your original purchase price and subsequent reinvestment). You must prorate your depreciation for the year in which you or your affiliate purchased the system to reflect the portion of that year for which you or your affiliate own the system.

If you or your affiliate purchase a transportation system at arm's length after the effective date of the rule from anyone other than the original owner, you must assume the depreciation schedule of the person who owned the system on the effective date of the rule.

Thus, under the final rule, if you purchased a pipeline before the effective date of this rule (whether from the original owner or a subsequent owner), you now may calculate depreciation based on your purchase price. From now on, you may use your purchase price as your basis only if you purchase the pipeline from the original owner. If you purchase a pipeline from anyone other than the original owner, you will assume the seller's depreciation schedule. MMS believes that these provisions balance the competing considerations arising from the December 1999 proposal and minimize the burdens on both the lessees and the agency.

The second change proposed in December 1999, at § 206.111(g)(3) and adopted in the final rule as § 206.111(j), provides that even after a transportation system has been depreciated below a value equal to ten percent of your original capital investment, you may continue to include in the allowance calculation a cost equal to ten percent of your total capital investment in the transportation system multiplied by a rate of return under paragraph (h) of this section, regardless of the pipeline's depreciation status. (Under the current regulations a lessee is not allowed to claim any depreciation or return on capital once a pipeline is fully depreciated.) This is only to calculate the return component of the transportation allowance; you still must follow the depreciation schedule for calculating the depreciation component of the allowance. So while you are permitted to take a return component equal to the allowable rate of return times ten percent of the total capital investment each year after you have depreciated your facility to the ten percent level, you may claim only the actual depreciation according to the depreciation schedule. Thus, you will be eligible for a return component even when you can no longer claim depreciation.

In the final rule, we also have added a clarifying paragraph (2) to specify that in calculating royalties paid on production after the effective date of the rule, you may apply this paragraph to a transportation system that before the effective date of this rule is depreciated at or below a value equal to ten percent of your total capital investment. You may not adjust royalties paid for production in periods before the effective date of the rule incorporating this additional return on investment component.

Section 206.111(g)(4) of the December 1999 proposal (paragraph 206.105(b)(2)(B) of the current regulations) provides an alternative for transportation facilities first placed in service after March 1, 1988. In the December 1999 proposal, we asked for comments on whether this provision should be continued. In the final rule, we are deleting this paragraph. This paragraph is unnecessary in light of the changes we are making to the calculation of actual transportation costs and because it is our understanding that this paragraph has been used in few, if any, situations.

The existing rule uses the Standard and Poor's Industrial BBB bond rate as an allowable rate of return on capital investment for producers who transport oil through their own pipelines (see 30 CFR § 206.157(b)(2)(v)). In the December 1999 proposal, we asked for comments on whether the existing rate of return should be changed. As noted above, some commenters suggested increasing the rate used in calculating the allowance to twice the Standard and Poor's BBB industrial bond rate. Two States and an individual commented that increasing the rate of return above the BBB rate is unnecessary and urged MMS to maintain the current rate of return.

As explained above in Section IX(a), MMS believes the BBB bond rate is a very appropriate rate of return and is retaining it in the final rule.

Section 206.112 What adjustments and transportation allowances apply when I value oil using index pricing?

Section 206.112 describes how to adjust the index price for location differentials, quality differentials, and transportation allowances depending on how you dispose of your oil.

In the February 1998 proposal, § 206.112 contained a ''menu'' of possible adjustments that could apply in different circumstances, and § 206.113 prescribed which of the adjustments from the ''menu'' applied to specific circumstances. The December 1999 proposal eliminated the ''menu'' and instead combined the previously proposed §§ 206.112 and 206.113 into one section that describes what adjustments apply when using index pricing. We have adopted that approach in the final rule. The ''menu'' of options is no longer necessary with the elimination of aggregation points and MMS-published differentials. This new paragraph covers all situations regardless of lease location, so there is no need for geographical breakdown of adjustments and allowances.

As proposed in December 1999, we eliminated the location differential between the index pricing point and the market center. This is because under the valuation procedures proposed under the February 1998 and December 1999 proposals and adopted in this final rule, the index pricing point and market center are synonymous.

Paragraph 206.112(a) covers situations where you dispose of your production under one or more arm's-length exchange agreements. In this case, you must adjust the index price for any location/quality differentials that reflect the difference in value of crude oil between the point(s) where your production is given in exchange and the point(s) where oil is received in exchange. You may also adjust the index price to reflect any actual transportation costs between the lease and the first point where you give your oil in exchange, and between any intermediate point where you receive oil in exchange to another point where you give the oil in exchange again, and between the last point you receive oil in exchange and a market center or refinery that is not at a market center. These costs are determined under §§ 206.110 or 206.111, depending on whether your transportation arrangement is at arm's length or not. (Note again, that if the transportation costs from the lease to the market center or alternate disposal point are already reflected in the location differential between the lease and the market center, you may not claim duplicate transportation costs.) A third adjustment (paragraph (d)) may be warranted if the quality of your lease production differs from that of the oil you exchanged at any intermediate point (for example, due to commingling at intermediate locations). This last adjustment would be based on pipeline quality bank premia or penalties, but only if such quality banks exist at intermediate commingling points before your oil reaches the market center or alternate disposal point.

For example, Company A transports its production from a platform in the Gulf of Mexico to an intermediate point under an arm's-length transportation contract for $0.50 per barrel. Company A then enters into an arm's-length exchange agreement between the intermediate point and the market center at St. James, Louisiana. Company A then refines the oil it receives at the market center, so it must determine value using an index price under § 206.103. The arm's-length exchange agreement between the intermediate point and St. James contains a location/quality differential of $0.10 per barrel. The average of the daily mean spot prices for St. James (the market center nearest the lease with crude oil most similar in quality to Company A's oil) is $20.00 per barrel for the production month. The value of Company A's production at the lease is $19.40 ($20.00—$0.10—$0.50) per barrel.

Under paragraph 206.112(a), you must determine the differentials from each of your arm's-length exchange agreements applicable to the exchanged oil. Therefore, for example, if you exchange 100 barrels of production under two separate arm's-length exchange agreements for 60 barrels and 40 barrels respectively, separately determine the location/quality differential under each of those exchange agreements, and apply each differential to the corresponding index price. As another example, if you produce 100 barrels and exchange that 100 barrels three successive times under arm's-length agreements to obtain oil at a final destination, total the three adjustments from those exchanges to determine the adjustment under this subparagraph. (If one of the three exchanges were not at arm's length, you must request MMS approval under paragraph (b) for the location/quality adjustment for that exchange to determine the total location/quality adjustment for the three exchanges.) You also could have a combination of these examples.

Paragraph 206.112(b) addresses cases where your exchange agreement is not at arm's-length. In that event, you must request approval from MMS for any location/quality adjustment.

Paragraph 206.112(c) addresses cases where you transport your production directly to a market center or to an alternate disposal point (for example, your refinery), and establish value based on index prices under § 206.103.

In the case of transportation directly to a refinery, you would deduct from the index price your actual costs of transporting production from the lease to the refinery with the costs determined under §§ 206.110 or 206.111 and any quality adjustments determined by pipeline quality banks under paragraph 206.112(d). The index pricing point is the one nearest the lease.

For example, a lessee or its affiliate in the Gulf of Mexico might transport its production directly to a refinery on the eastern coast of Texas and not to an index pricing point. Because that production is not sold at arm's length, the lessee must base value on the average of the daily mean spot prices for St. James, less actual costs of transporting the oil to the refinery and any quality adjustments from the lease to the refinery.

Likewise, if a lessee or its affiliate transports Wyoming sour crude oil directly to its refinery in Salt Lake City, Utah, and values the oil based on paragraph 206.103(b)(3), the lessee must base value on the average of the daily Cushing spot prices, less the actual cost of transporting the oil to Salt Lake City and any quality adjustments between the lease and the refinery.

When production is moved directly to a refinery and value must be established using an index, issues arise because the refinery generally is not located at an index pricing point. Consequently, the lessee does not incur actual costs to transport production to an index pricing point, and in any event, the production is not sold at arm's length at that point. The principle underlying the rules and cases granting allowances for transportation costs is that the lessee is not required to transport production to a market remote from the lease or field at its own expense. When the lessee sells production at a remote market, the costs of transporting to that market are deductible from value at that market to determine the value of the production at or near the lease. Where sales occur only at or near the lease, the question of a transportation allowance, as that term always has been understood, does not arise. However, because the lease and the index pricing point may be distant from one another, there is a difference in the value of the production between the index pricing point and the location of the lease. The question becomes how to determine or how best to approximate that difference in value.

In theory, one solution would be for MMS to try to derive what it would cost a lessee to move production from the lease to the index pricing point. There are, in MMS's view, several problems with such an approach. First, it would require a burdensome information collection from industry and impose substantial information collection costs on many parties to whom the resulting calculation may never be relevant. Second, in many cases it may well not be possible to obtain information on which to base such a calculation. In many instances, it is likely that no production from the lease or field is transported to the index pricing point that applies under § 206.103. Consequently, in such cases there would be no useful data on which such a cost derivation could be based.

Another possible solution, in theory, would be for MMS to derive a location adjustment between the index pricing point and the refinery. This might be possible if, for example, there are arm's-length exchanges of significant volumes of oil between the index pricing point and the refinery, and if the exchange agreements provide for location adjustments that can be separated from quality adjustments. But establishing such location adjustments on any scale again would require a burdensome information collection effort. MMS also anticipates that in many cases there would be no useful data from which to derive a location adjustment.

As we explained in the December 1999 proposal, MMS therefore believes that the best and most practical proxy method for determining the difference in value between the lease and the index pricing point is to use the index price as value at the refinery, and then allow the lessee to deduct the actual costs of moving the production from the lease to the refinery. This is not a ''transportation allowance'' as that term is commonly understood, but rather is part of the methodology for determining the difference in value due to the location difference between the lease and the index pricing point. Nevertheless, it is appropriate to include this deduction for situations in which index pricing is used.

MMS included this same method in the January 1997 proposal and did not receive any suggestions for alternative methods. We received few comments on this issue in response to the February 1998 proposal. However, one State commented that this method could result in calculation of inappropriate differentials. Absent better alternatives, MMS believes this method is the best and most reasonable way to calculate the differences in value due to location when production is not actually moved from the lease to an index pricing point.

However, if a lessee believes that applying the index price nearest the lease to production moved directly to a refinery results in an unreasonable value based on circumstances of the lessee's production, paragraph 206.103(e) allows MMS to approve an alternative method if the lessee can demonstrate the market value at the refinery. Although we received a few comments that MMS should not allow such requests, MMS believes it should leave this opportunity open for those limited cases where the procedure discussed above may be shown to be inappropriate, as we explained in the December 1999 proposal. MMS will do a thorough review and analysis of any such requests and will only approve them where the proper alternative value or procedure has been clearly demonstrated.

It is the lessee's burden to provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to: (1) costs of acquiring other crude oil at or for the refinery; (2) how adjustments for quality, location, and transportation were factored into the price paid for the other oil; (3) the volumes acquired for the refinery; and (4) other appropriate evidence or documentation that MMS requires. If MMS approves an alternative value representing market value at the refinery, there will be no deduction for the costs of transporting the oil to the refinery unless it is specifically identified in the Director's approval. Whether any quality adjustment is available depends on whether the oil passes through a pipeline quality bank or if an arm's-length exchange agreement used to get oil to the refinery contains a separately-identifiable quality adjustment.

Paragraph 206.112(c) also covers situations where you transport your oil directly to an MMS-identified market center. To arrive at the royalty value, you would adjust the index price by your actual costs of transportation under §§ 206.110 and 206.111. A second adjustment (paragraph (d)) may be warranted if the quality of your lease production differs from the quality of the oil at the market center. This adjustment would be based on pipeline quality bank premia or penalties, but only if such quality banks exist at the aggregation point or intermediate commingling points before your oil reaches the market center.

For example, Company A transports its production from a platform in the Gulf of Mexico to St. James, Louisiana, under a non-arm's-length transportation contract with its affiliate. The actual cost of transporting production under § 206.111 is $0.50 per barrel. The average of the daily spot prices at St. James is $20.00 per barrel for the production month. The value of Company A's production at the lease is $19.50 ($20.00–$0.50) per barrel.

As discussed earlier in this preamble, MMS received a variety of comments, pro and con, about the differentials used in § 206.112. MMS believes the criteria laid out in this final rule are fair and reasonable and best represent a balanced response to the comments received.

In this final rule, paragraph 206.112(e) contains language from proposed paragraph 206.112(f) of the February 1998. It states that the term ''market center'' means Cushing, Oklahoma, when determining location/quality differentials and transportation allowances for production from leases in the RMR.

In the February 1998 proposal at paragraph 206.112(e), and in the December 1999 proposal and the final rule at paragraph 206.112(d), MMS added a separate adjustment to reflect quality differences based on quality banks between your lease and an alternate disposal point or market center applicable to your lease. You would make these quality adjustments according to the pipeline quality bank specifications and related premia or penalties that may apply in your specific situation. If no pipeline quality bank applies to your production, then you would not take this quality adjustment. Likewise, if a quality adjustment is already contained in an arm's-length exchange agreement from the lease to the market center, you could not also claim a pipeline quality bank adjustment from the lease to the aggregation point or market center. MMS believes this additional adjustment would more accurately reflect actual quality adjustments made by buyers and sellers.

In this final rule we added a new paragraph 206.112(g) to clarify that regardless of how you dispose of your production and which adjustments might otherwise apply, you cannot include separate transportation or quality adjustments that duplicate one another. That is, any time you take one of the listed adjustments, you cannot duplicate any portion of that adjustment in part or all of any other adjustment that otherwise would be allowable.

Paragraph 206.112(f) of the December 1999 proposal and of this final rule addresses situations where you may not have access to differentials between the lease and the alternate disposal point or market, or you may not have access to the actual transportation costs from the lease alternate disposal point or market center. In such cases, which should be infrequent, MMS will permit you to request approval for a transportation allowance or quality adjustment. In determining the allowance for transportation from the lease to the alternate disposal point or market center, MMS will look to transportation costs and quality adjustments reported for other oil production in the same field or area, or to available information for similar transportation situations. Under paragraph 206.112(b), you must also request approval from MMS for any location/quality adjustments when you have a non-arm's-length exchange agreement.

As discussed above, paragraph (g) of § 206.112 of the December 1999 proposal and the final rule clarifies that you may not use any transportation or quality adjustment that duplicates all or any part of any adjustment that you use under this section.

Section 206.113 How will MMS identify market centers?

Section 206.113 of the December 1999 proposal and the final rule is paragraph 206.105(c)(8) of the 1997 proposal and

§ 206.115 of the February 1998 proposal, except that we have eliminated the identification of aggregation points and we have made minor wording changes. MMS has eliminated the list of aggregation points identified in the January 1997 proposal in conjunction with the elimination of Form MMS–4415.

In the preamble to the January 1997 proposal, MMS listed market centers for purposes of the rule. That list included Guernsey, Wyoming. MMS has eliminated Guernsey as a market center for the reasons given earlier. Also, we received comments that simply using Los Angeles and San Francisco as market centers for ANS pricing purposes was too broad and that multiple, local delivery points in and near these two cities should be included in the market center definition. So, for purposes of this rulemaking, the Los Angeles market center includes Hines Station, GATX Terminal, and any of the refineries located in Los Angeles County. The San Francisco market center includes Avon, or any of the refineries located in Contra Costa or Solano Counties.

Section 206.114 What are my reporting requirements under an arm's-length transportation contract?

Section 206.114 of the December 1999 proposal and the final rule is paragraph 206.105(c)(1) of the existing rule rewritten in plain English.

Section 206.115 What are my reporting requirements under a non-arm's-length transportation contract?

Section 206.115 of the December 1999 proposal and the final rule is paragraph 206.105(c)(2) of the existing rule rewritten in plain English, except paragraph 206.105(c)(2)(iv) is deleted as described in the preamble to the January 1997 proposal. We also added a sentence clarifying that when you adjust your estimated allowance to an actual allowance, § 206.117 will apply.

Section 206.116 What interest and assessments apply if I improperly report a transportation allowance?

Section 206.116 of the December 1999 proposal and the final rule is paragraph 206.105(d) of the existing rule rewritten in plain English.

Section 206.117 What reporting adjustments must I make for transportation allowances?

Section 206.117 of the December 1999 proposal and the final rule is paragraph 206.105(e) of the existing rule rewritten in plain English.

Section 206.118 Are costs allowed for actual or theoretical losses?

Section 206.118 of the December 1999 proposal and the final rule is paragraph 206.105(f) of the existing rule rewritten in plain English. Reference to the FERC- or State regulatory agency-approved tariffs was deleted in the January 1997 proposal, and since this final rule does not provide the option for lessees who own pipelines to request use of such tariffs in lieu of their actual costs, the tariff reference is not in this final rule. Although we received a comment that actual or theoretical losses are real costs of transportation, this section is simply a continuation of longstanding policy.

Section 206.119 How are the royalty quantity and quality determined?

Section 206.119 of the December 1999 proposal and the final rule is § 206.103 of the existing rule rewritten in plain English.

Section 206.120 How are operating allowances determined?

Section 206.120 of the December 1999 proposal and the final rule is § 206.106 of the existing rule rewritten in plain English.

Section 206.121. Is there any grace period for reporting and paying royalties after this subpart becomes effective?

In the January 2000 public workshops, some commenters discussed the need for systems changes in their companies to comply with certain provisions of the December 1999 proposal. In the final rule, we have added a new § 206.121 in an effort to facilitate that transition. Under this section, you may adjust royalties reported and paid for the first three production months after the effective date of this rule without liability for late payment interest if the adjustment results from systems changes needed to comply with new requirements imposed under this subpart that were not requirements under the predecessor rule. This is not a blanket exemption from late payment charges. The lessee will bear the burden of being able to demonstrate that the adjustment resulted from a systems change necessitated by the final rule. While the lessee may be billed for interest, it will be credited only if MMS is satisfied that the adjustment that caused the interest bill was due to systems changes needed as a result of this rule.

Decision to delete proposed change to royalty-in-kind procedures at 30 CFR 208.4(b)(2)

In the January 1997 proposal, MMS proposed to modify the procedures for determining the sales price billed to the RIK purchaser. The proposal would have used the index price less a location/quality differential specified in the RIK contract. MMS has decided not to proceed with this approach. Instead, MMS will establish future RIK pricing terms directly within the contracts it writes with RIK program participants. MMS's goal still is to achieve pricing certainty in RIK transactions. But because of its revised plans, MMS has dropped its proposed January 1997 change to 30 CFR 208.4(b)(2).

XI. Procedural Matters

General Comments Relating to Procedural Matters for the December 1999 Proposal

With respect to the procedural matters of this proposed rule, MMS received comments from several parties, including U.S. Senators, with the most detailed comments coming from one entity (the Barents Group). Many industry groups endorsed the Barents Group's comments. We received no comments related to procedural matters from States, watchdog groups, or private citizens.

The comments generally were focused on the burden estimates associated with implementing the rule. We will address the comments in the sections that discuss the respective requirements.

General Comments Relating to Procedural Matters for the February 1998 Proposal

MMS received comments regarding various procedural matters involved in the February 1998 proposed rule from one entity (The Barents Group) that were endorsed by several companies and industry organizations. One comment centered on overall procedure, while two other comments specifically addressed Executive Order (E.O.) 12866 and the Regulatory Flexibility Act. We will address the overall procedure comment here, and we will address the specific comments in the sections that discuss the respective requirements.

Issue: Procedures not followed with the latest publication and re-opening of the comment period

Summary of Comments: The commenter believes that the Administrative Procedure Act (APA) requires any comment period to remain open for at least 60 days. Furthermore, an advance copy of the rule (in this case the July 1998 proposal) should be sent to the Office of Management and Budget (OMB) for review prior to any publication. The comment period for this rule was much less than 60 days and OMB never received a copy of the rule.

MMS Response: The APA does not specify a minimum time period for accepting comments. The APA only requires a ''reasonable'' comment period depending on the particular facts of the rule. Generally, the comment period is 60 days for proposed rules, and shorter periods for supplementary proposed rules. The July 1998 proposal was not an initial proposed rule; it was a further supplementary proposed rule representing the fifth in a series of proposed and supplementary proposed rules. Given the numerous times this rule has been published for comment and the many meetings held over the last three-plus years, MMS believes the brief comment period (July 9 through July 31) for the July 1998 proposal, which merely addressed issues that had been commented on before, was more than adequate. The July 1998 proposal included few changes to previous versions of the rule; the major substance of the rule had been addressed several times in great detail. Additionally, MMS provided OMB a copy of the February 1998 proposal, and OMB approved the rule for publication. MMS made only minor modifications to the February 1998 proposal in its July 1998 proposal, and MMS provided a copy of the July 1998 proposal to OMB.

The Regulatory Flexibility Act

The Department certifies that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

This rule establishes the methodology royalty payors are to use in calculating royalty payments owed the Federal Government for oil produced on Federal leases, both onshore and offshore. There are approximately 800 such royalty payors.

The majority of royalty payors operate onshore and are smaller companies that sell the oil they produce to third parties in arm's-length transactions. They generally do not engage in downstream petroleum businesses. Larger companies usually operate offshore as well as onshore and have the resources needed to meet the technical and financial challenges associated with producing oil on the Outer Continental Shelf, especially in deep water. Many of these larger firms are integrated companies that produce crude oil, operate refineries, or market petroleum products at the wholesale and retail levels.

This rule provides that lessees that sell their oil under arm's-length transactions will continue to report and pay royalties based on their gross proceeds. Consequently, this rule will not affect the amount of royalties they pay, nor the manner in which they calculate the royalty. Generally, only integrated payors who do not trade oil at arm's-length will be required to pay royalties based on the rule's non-arm's-length provisions.

According to the Small Business Administration (SBA), drilling companies and companies that extract oil, gas or natural gas liquids having fewer than 500 employees are defined as small businesses. SBA defines refining companies as small if they employ less than 1,500 people. Based on the 500-employee standard for oil extraction companies, we estimate that over 90 percent (or about 740) of the 800 royalty payors, are small businesses.

MMS's analysis of 1998 data shows that a total of 45 royalty payors would have been required to value their production as less than arm's-length for royalty purposes. The other 755 companies sold the oil they produced under arm's length transactions and would not be affected by this rule. In comparison to their actual royalty payments, MMS estimates that the 45 affected payors would have paid additional royalties totaling $67.3 million.

Using company employment data, we determined that nine of the 45 companies are small businesses. (Since these companies are refiners as well as producers, we used the SBA standard of 1,500 or fewer employees for determining which companies were small.) Consequently, the nine small businesses who will be affected by the rule represent only 1.2 percent of the 740 small businesses who pay royalties on Federal oil. Our analysis of these nine companies' 1998 royalty payment data indicates that they would have paid additional royalties of approximately $280,000 or an average of about $31,100 each in 1998.

In addition to the impact on royalty payments, the rule will impose certain paperwork burdens as discussed in the Paperwork Reduction Act section of this preamble. Our analysis of the additional reporting burden for small companies required by this rule is 31.25 hours per company. Based on a cost of $50 per hour, the total cost to the nine affected small companies is about $14,000, or an average of about $1,600 per company.

In summary, nine small businesses will be affected economically by this rule. Their costs will include about $280,000 in additional royalties and $14,000 in reporting burdens for a total cost of $294,000. On average, the cost per company is about $32,700 annually ($31,100 in additional royalties and $1,600 in reporting burden).

Given the small number of companies and the costs involved, this rule will have minimal impact on companies producing oil on Federal lands, including the 45 royalty payors most directly affected. As noted, most of these companies are large integrated oil companies with very substantial technical, financial and real property resources. The additional costs that may result from the rule are small when compared to the revenues the companies earn from the oil they produce from Federal leases and upon which royalties are paid. As discussed in the economic analysis, the benefits of pricing simplification and the savings associated with transportation allowance changes would outweigh any additional administrative costs associated with this proposed rule. This analysis is available upon request.

Because of the lack of a substantial direct impact on the producing companies, the rule will have no secondary impacts on small businesses, such as oil field service companies, supply boat operators, etc., that conduct business with the producing companies.

Consequently, MMS concludes that this rule will not have a significant impact on a substantial number of small business entities.

Summary of Comments Related to the December 1999 Proposal:

One party commented that all small businesses will be affected by the rule, not just the nine businesses MMS identifies. Many independents have marketing affiliates and also act as designees on behalf of other lessees. These aspects were not considered in MMS's analysis.

MMS Response: MMS has maintained throughout this rulemaking that lessees who sell their oil at arm's length will continue to report and pay on their gross proceeds. Almost all of the identified small businesses dispose of their production through arm's-length contracts. Further, small businesses who market through an affiliate may report and pay on the affiliate's arm's-length gross proceeds.

Lessees that have designees reporting for them will incur no additional burden, while the designees themselves likely will not either. In the majority of cases, lessees who have designees reporting on their behalf are smaller firms whose gross proceeds from arm's-length sales will be the reported royalty value. In these cases, small companies with interests in Federal leases would rather dispose of production at arm's length and allow a designee to report for them. The rule imposes no additional burden in these cases. MMS therefore does not believe that the rule will impose significant burdens on all small businesses.

Summary of Comments Related to the July 1998 Proposal: MMS received one comment on the July 1998 proposal. The comment and MMS's response follow.

Summary of Comments: MMS has not met the requirements of the Regulatory Flexibility Act because the rule does significantly impact small businesses.

MMS Response: As stated below, our analysis concludes that the requirements of this final rule will not significantly impact a substantial number of small businesses. In general, only integrated payors with either a refinery, a separate marketing entity, or both will pay additional royalties. Such lessees are typically larger in size and able to absorb any additional burden (however small) the rule may impose. In the few cases where small businesses may be affected, the impact will be minimal.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This final rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule:

(a) Will not have an annual effect on the economy of $100 million or more;

(b) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; and

(c) Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

See the Executive Order 12866 analysis later in this preamble for specific estimated effects of the rule.

Unfunded Mandates Reform Act of 1995

The Department of the Interior has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. § 1531 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on local, tribal, or State governments, or the private sector. This rule will not change the relationship between MMS and State, local, or tribal governments. The historical relationship between MMS and State and local governments will not change in any way. The rule will, in fact, increase State royalty revenues without imposing additional costs. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

See the Executive Order 12866 analysis later in this preamble for specific estimated effects of the rule.

Fairness Board and National Ombudsman Program

The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 regional fairness boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small businesses. If you wish to comment on the enforcement actions of MMS, call 1–888–734–3247.

Executive Order 13132 (Federalism)

In accordance with Executive Order 13132, this final rule does not have Federalism implications. This rule does not substantially and directly affect the relationship between the Federal and State governments. This final rule does not negatively affect the States' prerogatives regarding oil valuation or their share of oil royalty receipts. The affected States were heavily involved in the rulemaking process through their continued participation in MMS's numerous public workshops and submission of detailed comments at every stage of this lengthy rulemaking process.

The management of Federal leases is the responsibility of the Secretary of the Interior. Royalties collected from Federal leases are shared with State governments on a percentage basis as prescribed by law. This final rule does not alter any lease management or royalty sharing provisions. It determines the value of production for royalty computation purposes only. This final rule does not impose costs on States or localities. Costs associated with the management, collection and distribution of royalties to States and localities are currently shared on a revenue receipt basis. This final rule does not alter that relationship.

Executive Order 12630

The Department certifies that this rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, a Takings Implication Assessment need not be prepared under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Summary of Comments Related to the February 1998 and December 1999 Proposals: The proposed rule deprives lessees of their constitutionally protected property rights when royalties are paid based on a higher than actual lease sales price. This is a price that the lessee would find impossible to actually realize because it includes returns on investments and on downstream marketing profits. The commenter asserted that because such a taking will occur if the rule is approved, MMS must prepare a Takings Implication Assessment pursuant to Executive Order 12630.

MMS Response: Executive Order 12630 requires a Federal agency to justly compensate a private property owner if private property is taken for public use. Disagreements over methods of valuing production for royalty purposes do not change the property relationship between a lessee and the Federal lessor, and do not operate to deprive the lessee of any property interest. Even if a particular valuation method is held to be unlawful or unauthorized, the remedy is to overturn the unauthorized agency action. This does not have constitutional takings implications.

Executive Order 12866

The Office of Management and Budget (OMB) determined that this rule is a significant rule under Executive Order 12866 Section 3(f)(4). Although we estimate that the rule will have an effect less than $100 million on the economy, this order states that a rule is considered a significant regulatory action if it ''raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.'' OMB determined that this rule raises novel legal or policy issues.

MMS met the Executive Order 12866 regulatory compliance and review requirements when it developed its February 1998 proposal. MMS's analysis of the revisions it made to the February 1998 proposal indicated those changes would not have a significant economic effect, as defined by Section 3(f)(1) of this Executive Order.

This rule will not adversely affect in a material way the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. In its February 1998 proposal, MMS's analysis of 1996 data estimated that the rule would have had an economic impact of approximately $66 million in increased royalty collections annually. Because a substantial period of time elapsed since the initial analysis, MMS has performed a similar analysis comparing actual 1998 royalties paid with those we estimate would have been required had this rule been in effect. This recent analysis showed the rule would have had an economic impact of approximately $67 million in increased royalty collections annually, or about the same impact estimated earlier.

MMS completed a Record of Compliance (ROC), an internal document that was not published in the **Federal Register**, in conjunction with the December 1999 proposed rule. The conclusions that we reached in the ROC continue to apply to this final rule. The ROC contains the detailed analysis required under Executive Order 12866. Also, we present the economic analysis of this rule's impacts later in this section.

This rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency. We are not aware of any actions taken or planned by other agencies, State or Federal, that are similar to this one or that this rule would interfere with.

This rule does not alter the budgetary effects of entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

As part of the procedural matters associated with the December 1999, July 1998, and February 1998 proposals, MMS accepted comments on the specific approach, assumptions, and methodology used in the Executive Order 12866 analysis. For the December 1999 proposal, MMS received detailed comments from groups representing industry, producing companies and a Senate group. For the February 1998 proposal, MMS received a detailed report from one commenter and comments from two other organizations regarding the analysis. For the July 1998 proposal, MMS received one comment (from the Barents Group). MMS's responses to all of those comments follow. MMS did not receive any additional comments on the Procedural Matters in response to the March 1999 notice.

Comments Related to the December 1999 Proposal:

(a) Necessity of E.O. 12866 Analysis

Summary of Comments: One party commented that MMS is required to perform an analysis under Executive Order 12866 because this rule raises novel legal requirements. Further, this analysis requires a complete examination of all feasible alternatives. MMS has not completed this required analysis.

MMS Response: MMS completed a ROC, an internal document that was not published in the **Federal Register**, in conjunction with the December 1999 proposed rule. The conclusions that we reached in the ROC continue to apply to this final rule. The ROC contains the same detailed analysis required under Executive Order 12866. Additionally, we examined alternatives in detail over the entirety of this four-plus year rulemaking process. See the discussion of alternatives after the same comment was presented in response to the February 1998 proposed rulemaking.

The Office of Management and Budget determined this rule is a significant rule under Executive Order 12866 Section 3(f)(4). This order states that a rule is considered a significant regulatory action if it ''raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.'' MMS met the Executive Order 12866 regulatory compliance and review requirements when it developed its February 1998 proposal.

MMS's analysis of the revisions it made to the February 1998 proposal indicated those changes would not have a significant economic effect, as defined by Section 3(f)(1) of this Executive Order.

In its February 1998 proposal, MMS's analysis of 1996 data showed the rule would have had an economic impact of approximately $66 million in increased royalty collections annually. This estimate was based on a comparison of Federal oil royalties received in 1996 for both onshore and offshore production to those we would have expected under the provisions of the February 1998 proposal. Since the proposal used separate valuation methodologies for three geographic areas, so did the analysis. Because a substantial period of time elapsed since the initial analysis, MMS has performed a similar analysis comparing actual 1998 royalties paid with those we estimate would have been required had this rule been in effect.

(b) The Analysis Does Not Account for Designee Payors

Summary of Comments: Payors who pay on behalf of lessees will pass the incremental cost of a royalty increase on to their lessees. This cost is not accounted for.

MMS Response: MMS does not anticipate significant additional costs associated with payors who pay on behalf of lessees. See discussion above in the *Regulatory Flexibility Act* section.

(c) General Compliance with and Understanding of Rule

Summary of Comments: The rule is not clear in some respects. Companies will have to incur additional expense for training on how to comply with the rule.

MMS Response: Although the rule departs from the current royalty valuation methods for oil not sold at arm's length, MMS believes the rule is actually easier to understand and comply with. The rule reflects the way oil is bought and sold in the marketplace today. MMS believes that many industry professionals are familiar with the terms and methodology used in this rule. We agree that as with any new rule, there will be an adjustment period as lessees review the rule, analyze its application to their business, and implement its requirements. However, we do not believe this will be a significant cost.

MMS also intends to provide payor training in several locations after the publication of the final rule. Additionally, MMS will revise the Payor Handbook.

(d) Revision of Lessees' Computer Systems

Summary of Comments: Several parties are concerned that the proposed rule will necessitate a change in the computer systems already in place for paying royalty under the current regulations.

MMS Response: We received this comment in response to the February 1998 proposal. See our response below. None of these comments have explained how any necessary computer systems changes cause the rule to be inconsistent with Executive Order 12866.

(e) Burden Associated With Two-Year Election Requirement

Summary of Comments: We received a comment that there are significant internal evaluation costs associated with electing valuation methods every 2 years.

MMS Response: Internal economic decisions regarding the disposition of oil and what alternatives are financially beneficial to a lessee are a necessary part of a lessee's business. We do not believe that evaluating whether to value oil on the basis of gross proceeds or index for a property once every 2 years, in cases to which § 206.102(d) applies, is an onerous or difficult decision. Moreover, a lessee does not have to undertake the analysis to decide which method to elect if it does not want to; arm's-length gross proceeds is the primary measure of value in these cases.

(f) Differentials

Summary of Comments: One commenter asserted that additional costs will be incurred that MMS did not estimate for ''choosing and maintaining the acceptable recommendations for quality, location, and transportation differentials, and indexing methodology.''

MMS Response: Although we do not fully understand the comment, we did address the costs a company will incur to compute its own differentials.

(g) Affiliation Determinations

Summary of Comments: MMS did not account for the costs associated with companies asking MMS to determine if they are affiliated.

MMS Response: MMS believes that submitting facts relevant to determining if two persons are affiliated within the meaning of this rule is a straightforward and uncomplicated process and does not entail significant costs. MMS does not believe that submission of facts or documents for this purpose creates any inconsistency with Executive Order 12866.

(h) Audit Costs

Summary of Comments: MMS claims that the current audit burden will be reduced because the rule is simpler to comply with. All MMS is doing is replacing one audit cost for another because there is so much uncertainty in the rule. MMS does not provide enough specifics in the rule for a complete level of understanding.

MMS Response: MMS believes that the rule is understandable and that lessees should have all the elements necessary for proper valuation at its disposal. MMS believes this rule is more objective than some provisions in the predecessor rule. While any rule involves audit costs, MMS believes that this rule will reduce the overall audit burden.

(i) Requests for Valuation Determinations

Summary of Comments: MMS underestimates the number of determinations industry will request. The rule is so complex and uncertain that many companies will be requesting determinations.

MMS Response: MMS believes that the number of value determinations under § 206.107 of the final rule should be about the same as under the current rule, and they should be no more complex. We also believe that the number of other requests related to location and quality differentials should be less than or equal to the number we receive under the existing provisions concerning exceptions to computing actual costs of transportation. Additionally, MMS intends to provide ample payor training sessions and a revision of the Payor Handbook. We also added more examples to the preamble at industry's request to clarify how various provisions apply.

(j) Actual Transportation Cost Calculations

Summary of Comments: MMS does not address the burden of requiring a computation of ''actual costs'' as a result of disallowing FERC tariffs in non-arm's-length transportation arrangements. One industry commenter expressed concern about providing records to MMS.

MMS Response: We believe the burden estimates associated with the current approved Information Collection Request for Form MMS–2014 (OMB Control Number 1010–0022) already account for the task of computing non-arm's length transportation allowances as provided in the 1988 regulations. This allowance is based on a company's (or its affiliated pipeline's) actual costs of capital investment and operating and maintenance expenses.

That allowance calculation is based on the formula (D+R+E)/T, where D=annual depreciation of the pipeline's capital investment, R=return on undepreciated capital investment (the amount left each year after that year's depreciation has been deducted), E=annual operating and maintenance expenses, and T=the throughput volume of the pipeline.

While companies in the past may have been using FERC tariffs in lieu of this formula, we believe this cost information is readily available to the companies even in situations where an affiliate is involved. Additionally, we believe this calculation is relatively straightforward. While more lessees will have to calculate actual costs under this rule because it disallows FERC tariffs, the burden of calculating actual costs in each case has not changed substantially. Moreover, under the existing rules MMS has disallowed use of many FERC tariffs because FERC no longer ''approves'' tariffs for pipelines over which it has no jurisdiction.

The comment that these records must be sent to MMS is not accurate. We do not require lessees to submit this information initially for review (except in cases where lessees ask to exceed the presumptive allowance limits). We do, however, require that all information be available for audit. This is no different than the records maintenance requirement under the current regulations.

(k) MMS's Economic Analysis Understates Overall Costs

Summary of Comments: Several companies and industry groups expressed concern that MMS has underestimated the full impact of the rule. Many costs such as compliance, training, and the filing of additional guidance requests are not addressed. MMS claims of legal savings associated with the rule are not accurate because additional legal costs will be incurred in other areas.

MMS Response: MMS has attempted to categorize and accurately estimate all costs associated with the proposed rulemaking. Specific types of costs that commenters alleged that MMS did not take into account are discussed in other paragraphs of this section.

For the analysis associated with the December 1999 proposed rule, we did address and estimate the costs associated with compliance and filing of guidance requests. Determining the exact impact of these costs is very difficult and will vary for every organization affected by the rule. Our estimates attempt to categorize the average impact on an average payor affected by the rule. Some companies will spend more than others. Our estimates were intended to provide a general impact of the proposed rule.

Further, we have had discussions with OMB about our estimated impacts of the rule. OMB believes that our estimated impact analysis is sufficient and conforms with OMB requirements.

(l) MMS Fails to Account for Significant Costs to Small Businesses

Summary of Comments: Some commenters believe MMS fails to adequately address the impact on small businesses. The rule will affect all payors, not just a handful of major producers as MMS claims. Many small businesses have affiliates who will be forced to pay on the proposed index methodology.

MMS Response: MMS continues to believe this rule will not affect a substantial number of small businesses because we anticipate that most small businesses will continue to pay royalties based on their arm's-length gross proceeds, as they do under the current regulations. Approximately 800 businesses pay royalties to MMS on oil produced from Federal leases. MMS believes approximately 45 of the 800 total payors are likely to pay significant additional royalties under this rule. (We believe that most small businesses with affiliate sales will report the affiliate's arm's-length gross proceeds as value. Only small businesses with refinery capability that do not sell oil at arm's length will be affected substantially by the rule.) We further believe that only nine of those 45 payors are small businesses as defined by the U.S. Small Business Administration (companies with less than 1,500 employees). MMS further estimates that 97 percent of the remaining 755 payors, or 732, would be considered small businesses. The nine payors that we consider small businesses that we anticipate would be affected substantially by the rule make up less than 1.15 percent of all the payors reporting to MMS on oil produced from Federal leases and less than 1.25 percent of all the small businesses reporting to MMS on oil produced from Federal leases.

Our internal economic analysis of impacts on small businesses shows that benefits of pricing simplification and the savings associated with transportation allowance changes are likely to outweigh any additional administrative costs associated with this rule.

(m) Burden Associated With Compliance, Information Requirements, and the Rule in General

Summary of Comments: Congressional comments stressed the point that an overly burdensome rule will discourage further domestic oil exploration and development, and that any further burden on industry for information should be limited to establishing the value at the lease—not downstream of the lease.

Several groups from industry commented that the rule will increase administrative burden on both MMS and the producer. For example, MMS will have many requests from industry about value and quality determinations whenever companies believe that index pricing overstates the real value of their Federal oil production. MMS will not be able to timely respond. Thus, industry will have less certainty than before. Ignoring the FERC tariff methodology requires a double burden on lessees, *i.e.,* having to apply two different sets of rules (FERC's and MMS's). The rule will drive producers to revamp business practices—especially in the mid-stream marketing arena.

On the other hand, a State commented that the December 1999 proposal puts too much trust in the industry to supply information. Industry should be required to tell MMS when a balancing agreement is in place or when oil is subject to a call. This State stressed that MMS needs this information up front, not just in an audit. Effectively, the burden is on MMS for collecting this information. A watchdog organization agrees that it is imperative that industry inform MMS of balancing agreements.

MMS Response: MMS acknowledges that the rule will change the current valuation procedures for some integrated producers. However, we believe the rule actually results in simpler methodologies that are less burdensome than the current regulations.

We anticipate that the overall impact of the rule will be to significantly reduce the time involved in the royalty calculation process. Under the rule, in most cases lessees without arm's-length sales would report the adjusted spot price applicable to their production. For other than production in the RMR, the need to work through and apply the current benchmarks for non-arm's-length transactions would be eliminated. Many of the variables in royalty calculation under the previous rule have been eliminated. This should lead to additional savings in audit costs.

The comments regarding ''value at the lease'' have been addressed elsewhere in this preamble. The substance of these comments actually relates to downstream sales and what deductions are or are not proper in light of the lessee's duty to market.

The comments regarding having to apply different sets of rules between FERC and MMS are, in our view, misplaced. FERC is not charged with determining lessees' actual transportation costs for royalty purposes. Indeed, many of the pipelines for which lessees may have to calculate actual transportation costs are not even within FERC's jurisdiction, as explained above.

The comments regarding the timing of information on balancing agreements do not appear to warrant a change from the December 1999 proposal. Balancing agreements are relevant to the question of whether a particular contract reflects the total consideration for disposition of the oil. This is typically a matter addressed in the audit context.

(n) MMS's Economic Analysis Fails to Analyze Alternatives as Required by Law

Summary of Comments: A group representing industry believes MMS fails to adequately analyze alternatives such as taking royalty in kind or tendering. The commenter says that the Administrative Procedure Act requires a full economic analysis of all feasible alternatives.

MMS Response: See response in paragraphs (b), (c), and (d) below in the discussion of MMS's responses to the comments on the February 1998 proposal.

Comments Related to the July 1998 Proposal

Summary of Comments: Since MMS has significantly changed the rule since the February 1998 proposal, a new and revised analysis should be performed.

MMS Response: We revised our analysis using 1998 data. The procedures followed in the latest analysis are basically the same as those followed with the original analysis.

Comments Related to the February 1998 Proposal: (a) Marketing Costs

Summary of Comments: Some commenters asserted that the proposed valuation methodology will not arrive at the value of oil at the lease. They said the adjustments MMS proposes will not account for all costs associated with assessing value downstream and away from the lease. They argued that for computing value in situations not involving arm's-length sales, the rule imposes the equivalent of a tax by not allowing marketing cost deductions.

MMS Response: MMS's detailed responses to the obligation of the lessee to market production free of cost to the Federal Government are discussed in detail in Section III(i).

(b) Alternatives

Summary of Comments: MMS has not considered the appropriateness of non-regulatory alternatives such as taking royalty in kind (RIK) instead of in value.

MMS Response: The MMS has in fact considered several non-regulatory alternatives to the rule including RIK. In 1995, MMS undertook an RIK pilot project for gas produced from the Gulf OCS and is currently operating RIK projects in Wyoming (crude oil in-kind), offshore Texas in the zone governed by section 8(g) of the OCSLA (natural gas in kind), and in the Gulf of Mexico (natural gas in kind). The objective of these pilots is to test the administrative and economic feasibility of a variety of methods and conditions of RIK programs. But until MMS completes these pilots and analyzes the results, revisions to the valuation regulations are needed to assure receipt of market value. Also, unless *all* Federal oil is taken in kind in the future—an occurrence we do not foresee—valuation regulations still will be needed.

Furthermore, MMS published a **Federal Register** notice on September 22, 1997 (62 FR 49460), requesting comments on alternatives before proceeding with the rulemaking. While these are not ''non-regulatory'' alternatives, they demonstrate MMS's attempts to involve the public in suggesting different valuation methodologies. These alternatives were discussed above in Section V of this preamble.

In short, MMS has considered many alternatives to the rule and received numerous comments from interested parties along the way. The MMS believes the rule is a practical solution to establishing royalty valuation methods that capture the true market value of crude oil produced from Federal leases. MMS is considering non-regulatory alternatives such as RIK, but is not prepared to take a more significant portion of its oil in kind until or unless the results of its pilots so dictate. The other valuation alternatives mentioned above were deemed to be less desirable and more costly to implement than the final rule. For these reasons, MMS determined that they are not feasible alternatives or effective means to achieve the same results as the rule.

(c) Tendering Programs

Summary of Comments: Commenters on E.O. 12866 asserted that MMS is incorrect in assuming that a tendering program is costly and is only valid if a nearby index measure of value does not exist.

MMS Response: For areas other than the RMR, MMS views index prices as the most accurate measure of value for oil not sold at arm's length. As mentioned above, the costs of monitoring and establishing a workable tendering program, with adequate safeguards to prevent abuse, make it a less desirable alternative than index pricing. Because tendering is company-specific, information transfer costs and recordkeeping costs would be higher than the costs associated with using a transparent, reliable indicator of value, such as an index.

The reason that the final rule includes tendering as a valuation benchmark for the RMR is that there is no reliable spot or index price specific to that region.

(d) Industry-Proposed Benchmarks

Summary of Comments: Some commenters stated that MMS rejected an industry-proposed benchmark system based on the assumption that it was too costly and difficult to administer. It is not clear that the costs associated with the new rule are any less severe than the costs associated with this proposed benchmark system.

MMS Response: The Independent Petroleum Association of America (IPAA) originally submitted the proposed benchmark system referenced by this comment and has since submitted a modified valuation proposal they termed ''royalty valuation procedures'' (RVP's). MMS asked for comment on IPAA's original proposed benchmark system in a **Federal Register** notice on September 22, 1997 (62 FR 49460) (see above for specifics on the proposal and the responses we received). IPAA's modified proposal for sales not at arm's length allows the lessee to elect one of the following RVP's for a given period of time:

- Outright sales of significant quantities of like-quality crude in the field or area, including sales under ''tendering'' programs.
- Arm's-length purchases of significant quantities of like-quality crude in the field or area.
- Netback methodology using an index price or an affiliate's resale price minus all actual costs for transportation and value added by midstream activities.
- Potential use of outright arm's-length sales by third parties in the field or area once the trade press begins routinely to publish price data for a given field (this is something that the trade press currently does not do; nor are we aware of any trade press plans to publish such data).
- Potential use of prices published by MMS based on its RIK sales (this idea assumes that a RIK program is feasible and that data gathered from it would be applicable and in a usable form).

State commenters on the February 1998 proposal objected to IPAA's menu selection concept.

As discussed elsewhere in this preamble, the final rule uses index prices to value oil not sold at arm's length everywhere except in the RMR. While the final rule does not use RVP's for that region, it does use a set of benchmarks with some similarities to the RVP's. Also as discussed elsewhere in the preamble, MMS believes that except for the RMR, spot prices are the best indicators of value.

In the public workshops, MMS explained in detail the numerous problems associated with using area or regional sales and purchases as a measure of value. The potential for uncertainty in the terms ''significant quantities,'' ''like-quality,'' and ''field or area,'' leads to significant audit burdens on lessees and MMS. Likewise, the first and second RVP's require the lessee to timely obtain access to arm's-length contracts in the field or area. The final rule adopts part of the third RVP, with deductions limited to the actual costs of transportation as prescribed in the rule, as the single valuation method for all production not sold at arm's-length, except in the RMR, where an index price is used as the third benchmark. However, as discussed in Section III(i) of the preamble, the final rule does not allow a deduction for midstream marketing activities.

The last two of IPAA's proposed benchmarks are offered only as potential measures, and IPAA admits they cannot be implemented currently. MMS is open to studying these proposals in the future if they become viable.

Finally, MMS does not believe that lessees should be permitted to select a valuation method simply because it would be to the lessee's monetary benefit. Value should be based on uniform standards applicable to all lessees similarly situated. In other words, valuation should not be based on a menu, but rather on a hierarchy of established standards.

(e) Spot Prices

Summary of Comments: In their comments on E.O. 12866, commenters disagreed with MMS's assertion that spot and spot-related prices drive the manner in which crude oil is bought and sold today in the United States.

MMS Response: MMS's detailed response to the adequacy of spot prices is contained in Section VI(e).

(f) Cost-benefit Analysis of Alternatives

Summary of Comments: Commenters stated that MMS fails to meet the requirements of E.O. 12866 by not performing a cost-benefit analysis of any of the alternatives. They say MMS simply presents a few unsubstantiated reasons for not using alternatives, which does not allow MMS to choose the most efficient alternative. Further, according to the commenters, MMS has not investigated which, if any, alternatives arrive at value at the lease.

MMS Response: The final rule is the culmination of a four-plus year rulemaking effort. Throughout this process MMS explored and discussed numerous valuation alternatives with States, consultants, interest groups, industry groups, and congressional staff. MMS has adopted, at least partially, many of the alternatives suggested by commenters. However, several suggested alternatives were based on propositions for which no data exists for conducting a cost-benefit analysis. Furthermore, expert consultant feedback and State support substantiated our reasons for not using alternative valuation methods.

As mentioned previously, MMS is in the process of implementing several RIK pilot programs in order to determine the feasibility of such an approach. Regardless of the outcome of these pilots, it is still necessary to have oil valuation regulations in place for the areas where RIK is not feasible.

(g) MMS's Costs Related to Form MMS–4415

Summary of Comments: Commenters stated that by MMS's own calculations, MMS assumes that it will receive approximately 1,750 Form MMS–4415 reports annually. The MMS assumes that its team of GS–9 employees would take only two minutes per form to collect, sort, and file the documents. It is likely that this cost is understated.

MMS Response: MMS has eliminated Form MMS–4415 in the final rule.

(h) Form MMS–4415 Data

Summary of Comments: Commenters asserted that MMS does not know what it is going to do with the collected data from the Form MMS–4415, so how can it accurately estimate the time required to analyze and publish the data?

MMS Response:

MMS has eliminated Form MMS–4415 in the final rule.

(i) Additional Industry Costs

Summary of Comments: Commenters on the E.O. 12866 asserted that MMS failed to estimate the additional costs that industry would be forced to incur under this rule. They include:

- The time required to calculate value under the rule.
- The cost of replacing or upgrading computer systems (the commenters say the proposed rule may require some companies to operate three different computer systems).
- The increased recordkeeping burden.
- The additional time required to complete other currently-approved MMS forms.

MMS Response: Industry stated that new computer systems are needed, with the possibility of three separate systems for the three regions of the country with separate valuation requirements. However, they did not provide any specifics on the costs of system modifications. While some payors will have to make some changes to comply with the final rule, as is the case with any new rule for a system involving automated reports and payments, industry has not shown that these costs will be excessive. Further, MMS believes that the majority of payors will continue to pay on the gross proceeds received under an arm's-length sale. This means that they will not incur any additional computer costs in complying with the arm's-length provisions of the new rule. For those not paying on gross proceeds, industry has not shown that the methods applicable to the three different regions of the country will require extensive computer systems overhaul or substantial additional staff. Therefore, the final rule includes three geographic regions as contained in the February 1998 proposal.

The new rule does not change statutory document retention requirements. There are no additional requirements associated with the rule that would result in additional information collection on any of MMS's current required forms.

(j) Lessees' Costs of Completing Form MMS–4415

Summary of Comments: Commenters asserted that MMS was correct in including the cost of completing proposed Form MMS–4415, but they said that MMS underestimated these costs.

MMS Response: MMS has eliminated Form MMS–4415 in the final rule.

(k) Sensitivity Analysis

Summary of Comments: Commenters assert that MMS has not used any sensitivity analysis in testing their assumptions.

MMS Response: The MMS believes that the assumptions made in formulating this rule are broad and basic enough that no sensitivity analysis is necessary.

(l) Market Distortions and Distributional Impacts

Summary of Comments: In their comments on E.O. 12866, commenters state that MMS has not considered the costs of market distortions or distributional impacts that would result from this rule. They say that MMS using an average of index prices to arrive at a market price in a month is not the same as arriving at a true market price for one particular individual. They assert that MMS ignores these distributional consequences under the apparent assumption that a single average market value concept is an adequate substitute for the range of market valuations that are established in the marketplace.

MMS Response: MMS believes that the index market price—adjusted for location, quality, and transportation costs—will approximate market values received for individual lease production.

(m) Lessees Will Avoid Filing Requirements

Summary of Comments: Commenters asserted that the costly filing requirements associated with Form MMS–4415 could cause lessees to restructure their transactions in such a way as to avoid triggering a filing requirement. They claim this is not a free-market outcome.

MMS Response: MMS has eliminated Form MMS–4415 in the final rule.

(n) FERC-Approved Tariffs

Summary of Comments: Commenters on the E.O. 12866 state that MMS requires the lessee to use ''actual costs'' of transportation rather than a FERC-approved tariff. They say this amounts to an additional cost or tax that the lessee must pay.

MMS Response: As explained above in the response to the comments received on the December 1999 proposed rule, this does not result in an extra cost or tax. All lessees claiming transportation allowances may deduct their actual costs of transportation. Those who pay others to transport their crude still may deduct a FERC tariff if that is the rate they pay at arm's length for the transportation.

(o) Baseline Years

Summary of Comments: Commenters assert that the choice of baseline years from which to calculate the benefits in MMS's impact analysis is very important. For example, in 1996, the average price per barrel of crude oil from Federal lands was $18.37, whereas recently oil prices have been as low as $13 per barrel. At lower prices, the relative differences become smaller.

MMS Response: MMS chose 1996 as a baseline year because that was the most recent year for which the normal corrections in royalty reporting were complete at the time the February 1998 proposal was published, and it represented a year with no market interruptions or anomalies. The implication that a lower oil price such as $13 per barrel could make MMS's estimates inaccurate, or the relative value differences smaller, is misplaced. It is expected that oil prices will vary over time, but the effect of a change in prices on the difference in royalty value between this rule and the existing rule is unknowable without a great deal of additional information. MMS therefore believes that there is no basis on which to argue that 1996 is an improper baseline year because prices supposedly were too high to be used in estimating the impact of the new rule.

Further, and not as a result of the comment above, we have updated the analysis using 1998 royalty data because a significant period of time had elapsed since our initial analysis. The results of the revised analysis are very similar to those of the study using 1996 data and reinforce its validity.

As stated earlier, 1996 was selected not because of absolute price levels but because it was the most recent year for which reasonably complete and corrected data were available. In any event, the relative difference in royalty collections at different price levels is irrelevant to the central purpose of the rule—ensuring payment of royalty on the market value of Federal crude oil.

(p) Assumptions Regarding Benefit Analysis

Summary of Comments: Commenters on the E.O. 12866 analysis believe that MMS's assumption that payors with no refining capacity would continue to pay on gross proceeds from arm's-length sales at the lease is incorrect. By the same token, producers/ marketers with refinery capacity will not always dispose of production at other than arm's length, and as a result may be forced to use the index methodology for all their oil.

MMS Response: MMS concedes that there may be cases where integrated lessees with refinery capacity sell their oil under true outright arm's-length sales. Contrary to the comments, they would be able to use their arm's-length proceeds in such cases. However, our audit work and the advice of various crude oil consultants indicate that most integrated producers are net purchasers of crude oil and either exchange their produced oil for oil closer to their refineries or directly transport their production to supply their refineries. In either case there is not an arm's-length sale of crude oil.

In contrast, lessees without refinery capacity generally either sell their oil at arm's-length or transfer their oil to an affiliate who subsequently sells the oil to an unaffiliated refiner. In either case, payors without refining capacity generally would value their production based on the gross proceeds received under an arm's-length contract. This is not a change from how they value production under the current rules. For purposes of estimating the revenue impacts of this final rule, MMS believes these assumptions are valid.

(q) Proprietary Data

Summary of Comments: Commenters assert that MMS used proprietary data in calculating its estimates, and disclosure was a problem with data used in the onshore analysis.

MMS Response: The Barents Group filed a Freedom of Information Act request to obtain all of the data supporting the E.O. 12866 analysis. MMS was able to provide all of the data for OCS leases. However, the data from onshore leases involves questions of proprietary information because of the limited number of payors on those leases, which would enable those who review that data to associate a price with an individual payor. MMS believes that the only way to accurately estimate the revenue impact of the rule is to use actual, company-submitted data.

(r) MMS's Spreadsheets

Summary of Comments: Commenters assert that MMS's spreadsheets are not easy to interpret or well documented. In many cases the steps have been aggregated into one, and as a result, it is difficult to determine how and why MMS proceeded as it did. Further, what MMS describes as its methodology is inconsistent with what the spreadsheets present.

MMS Response: MMS believes that the spreadsheets are adequate and the documentation is clear. From the detail of the comments provided it appears that the main ideas presented in the analysis were well understood.

(s) Analysis for Refiners Versus Non-Refiners

Summary of Comments: In its comments on the portion of the E.O. 12866 analysis for offshore California leases, one commenter asserted that producers without refinery capacity (*i.e.*, those who normally would be expected to pay on arm's-length gross proceeds) now pay royalty on a value that is 17.8 percent less than what they would pay if value were based on the index price. Further, they say that producers with refinery capacity (*i.e.*, those who normally do not have arm's-length gross proceeds) now pay royalty on a value that is 10.4 percent below an index price-based value. They implicitly accuse MMS of being contradictory in requiring producers with refinery capacity (who do not sell at arm's length) to pay on a higher index-based value, while at the same time accepting arm's-length gross proceeds that are lower than the value already reported by the producers who do not sell at arm's length.

MMS Response: First, MMS has no basis on which to evaluate the accuracy of the commenter's assertions, which amounted to summary figures in a table of the commenter's own making. The commenter did not submit the underlying documents on which its asserted figures were based or explain how it performed its calculations.

Second, even assuming arguendo that the commenter's calculations are accurate, the commenter tries to infer far too much from what may have occurred in 1 year in one area. While non-arm's-length reported values can be higher than some arm's-length gross proceeds in some circumstances, nothing in MMS's experience or the commenter's figures indicates that non-arm's-length transfer prices either are or could be expected to be consistently higher than arm's-length market prices.

Indeed, in most instances where oil is first transferred to an affiliated marketing entity and then resold at arm's length, the arm's-length resale price is higher than the inter-affiliate transfer price. As explained above, non-arm's-length transfer prices are not reliable indicators of what price production will bear in the market. Therefore, as discussed in detail throughout this preamble, MMS must look to other reliable indicators of value such as index prices to establish value in those cases.

(t) Transportation Adjustments in the Analysis

Summary of Comments: Commenters assert that MMS states that for its comparison, it used prices reported on the Form MMS–2014 less any reported transportation allowances. Yet they say that when the spreadsheets are examined, it appears that transportation adjustments are not included.

MMS Response: MMS compared the price reported on Form MMS–2014 to the location, quality- (if applicable) and gravity-adjusted spot price at the first onshore delivery point, assuming that all payors reported a royalty due line (Transaction Code 01) representing the value at the onshore delivery point and a separate transportation allowance line (Transaction Code 11) representing the costs of transporting the oil to shore. That is, MMS compared (1) the onshore spot price, adjusted for the actual reported gravity at the least or a weighted average gravity for a unit, to (2) the price reported by the payor for the royalty due line without deducting any reported transportation allowance for that line. This allows an ''apples to apples'' comparison rather than comparing values at two different points.

If a payor incorrectly netted its transportation allowance from the reported royalty due instead of reporting the transportation allowance on a separate line, or if the payor sold its oil at the lease and incurred no transportation to move the oil to shore, MMS acknowledges that the revenue impact estimate for offshore California and the Gulf of Mexico may be overstated to that extent. However, if a payor does not report a separate transportation allowance on Form MMS–2014, MMS has no way of knowing the costs of transporting the production to shore to equate the reported price to the onshore spot price. Absent any other reasonable alternatives, MMS chose this methodology recognizing that the revenue impact could be slightly overstated, assuming at the same time that very few payors reported incorrectly. MMS correctly used the reported value on the Form MMS–2014 without including the reported adjustments for transportation.

(u) Gravity Adjustments

Summary of Comments: In their comments on the E.O. 12866 analysis, commenters stated that it is not clear why MMS does not use actual gravities in its offshore California analysis, but rather uses a weighted average gravity value within a unit and applies that value to all the leases in the unit. Commenters also believe that MMS does not account for gravity adjustments for oil in the range of 34° to 40° API and makes mistakes in calculating the gravity adjustments in several months.

MMS Response: MMS used the weighted average gravity for an entire unit because there were many cases where gravity was missing or reported incorrectly by royalty payors. In those cases, MMS believes that using a weighted average gravity is appropriate. However, the revised analysis that accompanied the December 1999 proposed rule used actual reported lease gravity. After an examination of the data, it appeared the reported gravity values were complete and accurate in 1998. Using a weighted average was not necessary.

MMS adjusted California crude oil production values using Chevron's posted price adjustment scale in effect for the month of production. The scale does indeed include adjustment values for the range of 34° to 40°; however, none of the weighted average gravities fell into this range. As a result, it was not necessary to include this adjustment in the calculations.

Additionally, there were months where the adjustment scale changed mid-month. As a result, some adjustments were based on a value that approximated the value in effect for the full month. For example, if the adjustment scale in effect for the first half of the month was $.15 per degree API gravity and for the last half of the month it changed to $.20 per degree, MMS used a value of $.17 per degree to approximate the value of the deduction for the entire month. So, although in such cases the commenters may have believed a mistake occurred, it did not.

(v) Use of Pipeline Tariffs in the Analysis

Summary of Comments: MMS uses pipeline tariffs in its estimates, yet the rule does not allow tariffs for payors with affiliated pipelines.

MMS Response: Absent other publicly-available information regarding transportation costs, MMS used tariffs in the analysis as a general proxy for location differentials between (1) the lease and (2) market centers for which spot prices are published. MMS has found that tariff rates generally exceed the actual costs of transportation, so using them in the analysis, if anything, would understate the revenue impact of the final rule.

(w) Analysis for New Mexico

Summary of Comments: Commenters assert that for MMS's onshore New Mexico estimates, a charge of $.25 per barrel is assessed for movement from aggregation points to Midland, Texas. The basis for this charge is never substantiated.

MMS Response: MMS based the $0.25 per barrel differential between aggregation points in New Mexico and the market center at Midland, Texas, on information it obtained from an industry contact who trades oil in that area.

(x) Differential Timing

Summary of Comments: Commenters said that lessees who are required to use differentials that are set once a year by MMS may overvalue or undervalue production because of the many changes in the market and oil quality over a year's time.

MMS Response: MMS has eliminated Form MMS–4415 in the final rule.

(y) Use of Unaudited Data

Summary of Comments: We received comments that MMS uses unaudited data for 1996, yet normal audit collections result in an average 3% revenue gain. This expected audit collection, the commenters allege, equals 71 percent of the MMS estimate of $66 million.

MMS Response: We do not know how much additional money will be collected through audit for any given period until audits are completed and money is collected. Nor do we know in advance exactly what the difference in royalty liability between this rule and the existing rule will be. Of necessity, our estimate of the revenue effects of this rule is just that—an estimate. But the objective in developing these regulations is to obtain a better measure of the real value of oil produced from Federal leases. We acknowledge that in many cases—arm's-length sales being a prominent example—royalty value will not change under this rule. In other cases, it will.

(z) Location Differentials, Rocky Mountain Region

Summary of Comments: Commenters asked if, as reported in its analysis, MMS could not calculate a differential for the RMR between Cushing, Oklahoma, and the fields of each State, how is industry expected to report this differential?

MMS Response: When MMS did its analysis, it did not have the necessary contracts in hand to calculate such differentials. Regardless, MMS believes that lessees that will be subject to index pricing generally will have sufficient information to accurately determine location/quality differentials, with relatively rare exceptions. Only lessees who sell their oil to affiliates who then either move the oil to market for sale at arm's-length or move the oil to a refinery are required (or can elect) to use index pricing. In those cases, MMS believes that lessees will either physically transport or exchange their oil to either a market center or a refinery and will therefore have the information necessary to determine location/quality and transportation adjustments from the index price. As a result, MMS has eliminated Form MMS–4415 in the final rule.

(aa) Quality Adjustments, Rocky Mountain Region

Summary of Comments: The MMS analysis for the RMR does not account for crude oil quality. This may invalidate the results of the analysis.

MMS Response: For the analysis that accompanied the December 1999 proposed rule, we had more complete information; we were able to isolate production to specific areas within some States. This better accounts for quality differences that may be found by commingling all production within a State.

(ab) Federal Administrative Savings

Summary of Comments: Commenters asked, if the rule will result in administrative savings to the Federal government, why are these savings not quantified?

MMS Response: The MMS is confident that administrative costs will be reduced. In our latest analysis, we make reference to administrative savings for both industry and the government. However, specifically quantifying these benefits is difficult. Audit costs are expected to fall as higher, correctly-reported royalties are realized initially when royalty is due.

MMS verification still will be needed, but we expect that the process will be more efficient.

(ac) MMS's Onshore California Analysis

Summary of Comments: Commenters stated that when MMS analyzed the onshore California impact, they only analyzed the Midway-Sunset field because the majority of Federal onshore oil production in California comes from this field. According to the commenters, MMS does not say whether the results are for the Midway-Sunset field only or somehow extrapolated to all fields onshore.

MMS Response: This analysis is a refinement of our earlier analysis (that used 1996 data) and contains several significant differences. The earlier analysis treated all onshore California Federal oil production as if it were produced in the San Joaquin Valley (from the Midway Sunset field). The current analysis used 1998 data and matches production to the area produced.

Following is a summary of MMS's revised economic analysis, which provides additional details for onshore California as well as the rest of the country.

Economic Analysis—Royalty Impact on Federal Lessees

Note: The complete analysis is not reproduced here, only the sections that generated the most comment. The entire analysis is available upon request.

We are revising our original estimate of approximately $66 million in increased royalty revenue that accompanied previous proposals of this rule. We used the same general approach to estimate the impact of the December 1999 proposal, except with updated 1998 data.

To estimate the impact and additional royalties collected under the December 1999 proposal, we divided the analysis of quantifiable benefits into three sections, consistent with the three geographic divisions of the proposal:

- California (both onshore and offshore)
- Offshore Gulf of Mexico (this also includes onshore New Mexico, Texas, and Louisiana)
- Rocky Mountain Region

For each of the geographic areas, we compared the royalty paid in 1998 for oil and condensate either directly to MMS or through the small refiner royalty-in-kind program to what would have been required under the valuation requirements of the December 1999 proposal. We examined each month of 1998 separately. We chose the year 1998 because it:

- Is the last complete year in which all months of data were available.
- Includes wide variations in prices over the 12-month span.
- Reflects data incorporating most of the edits and corrections performed by the exception processing modules in MMS's Auditing and Financial System/Production and Accounting and Auditing System.

We focused on the onshore leases in California, Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming because together they account for about 95 percent of total onshore Federal oil production. For offshore California and the Gulf of Mexico, we used 100 percent of the oil volumes and values for this analysis.

When examining the payments received from Federal onshore and offshore leases, we grouped all the royalty reporters into five separate categories:

1. Major integrated producers with refinery capacity;
2. Large, independent producers/marketers with refinery capacity;
3. Large, independent producers/marketers with no refinery capacity;
4. Small, independent producers with refinery capacity (this category is different than small businesses as defined by the Small Business Administration); and
5. Small, independent producers with no refinery capacity.

Offshore California

Under the December 1999 proposal, the value of production sold under an arm's-length contract would be the gross proceeds received under that contract. Oil not sold at arm's length would be valued on either (1) the average of the daily mean Alaska North Slope (ANS) spot prices published in an MMS-approved publication during the calendar month preceding the production month, or (2) the gross proceeds received by the affiliate under an arm's-length contract. The lessee would have to adjust the value for applicable location and quality differentials, and may adjust it for transportation costs. We believe that all large, independent producers/marketers with no refinery capacity (Category 3) and small independent producers (Category 5) would value crude on the basis of arm's-length gross proceeds. Therefore, we did not include them in the analysis. We examined the other three categories of royalty payors using the following procedure:

- We grouped all production by unit (*i.e.* Beta, Santa Ynez, etc.).
- We determined an average gravity for each lease in the unit.
- We made gravity adjustments to equate the unit oil to the 26.5° API ANS oil, using Chevron's California posted price gravity adjustment scale in effect during the month of production.
- We subtracted a location differential from the ANS value in Los Angeles to arrive at a value at the first onshore delivery point, which coincides with the value reported on Form MMS–2014. We used the following per-barrel location differentials relying on several sources, but primarily tariff schedules:

Beta: $0.10
Pitas Point: $0.50
Point Hueneme: $0.50
Point Pedernales: $0.50
Rocky Point: $2.20
Santa Clara: $0.50
Santa Ynez: $2.20

- We subtracted sulfur penalties from the ANS price where appropriate. These penalties were based on All-American Pipeline sulfur bank adjustments and consultant reports. We used a value of $0.56 for each percent sulfur above the benchmark ANS sulfur content of 1.1 percent. The per-barrel sulfur adjustments are:

Beta: $1.46
Point Pedernales: $1.62
Rocky Point: $1.79
Santa Ynez: $1.74
Santa Clara $1.46

- We then compared, for each month in 1998, (1) the location and quality-adjusted ANS price to (2) the actual price reported by each royalty reporter on Form MMS–2014. We then multiplied this incremental value by the royalty quantities reported on Form MMS–2014 to arrive at an overall net gain or loss associated with the rulemaking.

Our earlier analysis (using 1996 data) involved several factual differences. For example, the unadjusted average ANS price for 1996 was $20.45, versus $12.55 in 1998. (We wouldn't have expected different relative prices, in and of themselves, to cause a major difference in the results of the revised study, and that observation is borne out here.) Also, oil production from Federal Offshore California leases declined from 67,804,200 to 40,636,231 barrels—a drop of approximately 40 percent from 1996 to 1998. Further, the effective royalty rate for offshore California crude oil dropped by 1.6 percent (largely due to MMS-approved royalty rate reductions).

We updated the sulfur content related to various offshore fields and added a sulfur adjustment for the Santa Clara Unit. We made further revisions to the transportation rates from the onshore delivery points to the refining centers for offshore California production. While we recognize that not all payors will pay the same transportation rates, we used rates that we believe capture a reasonable representation on average of the rates paid by lessees.

Estimated 1998 revenue gains under this final rule are:

• Category (1)	$4,363,837
• Category (2)	241,247
• Category (4)	126,429
Total	$4,731,513

In 1998, California received about 4 percent of the Federal oil royalties from the California OCS—$1.96 million of $48.5 million total—under OCSLA section 8(g), 43 U.S.C. 1337(g), which provides for coastal States to share in royalties from Federal leases lying wholly or partially within three miles from the State's seaward boundary. Applying the same 4 percent to the above estimate equates to $189,261 in additional revenue for the State of California.

Onshore California

To determine the impact of the December 1999 proposal on onshore payors in California, we aggregated the production for Categories (1) and (4). This comprised over 80 percent of the Federal onshore California production. We assumed that Category (5) payors would pay royalties based on their gross proceeds. There was no Federal onshore California production for Categories (2) and (3) in 1998.

We arrived at a monthly price at the lease by taking the ANS spot price adjusted for:

1. Gravity (using Chevron's posted price gravity adjustment scales in effect during production year 1998 to reflect differences in ANS and onshore field reported gravity from Form MMS–2014).

2. Transportation charges:

San Joaquin Valley to Los Angeles—$1.00 per barrel
North San Joaquin Valley to Bay Area—$0.50 per barrel
Ventura Basin to Los Angeles—$.50 per barrel
Salinas Basin to Santa Maria—$1.50 per barrel

These four production areas represent over 80 percent of all Federal onshore California production.

We then compared, for each month in 1998, (1) the location and quality-adjusted ANS price to (2) the actual price reported by each category 1 and 4 royalty reporter on Form MMS–2014. We then multiplied this incremental value by the royalty quantities reported on Form MMS–2014 to arrive at an overall net gain or loss associated with the rulemaking.

As noted above, this analysis is a refinement of our earlier analysis (but using 1996 data) and contains some significant differences. The earlier analysis treated all onshore California Federal oil production as if it were produced from the Midway Sunset field. The current analysis used 1998 data and matches production to the area produced. Also, transportation rates are more reflective of lease locations than in the previous analysis. The rate for Salinas Basin crude assumes that all Federal oil produced there is transported by truck.

Oil production increased from onshore Federal California leases by about 8 percent from 1996 to 1998 although the effective royalty rate declined by 2.5 percent (largely due to stripper well royalty rate reductions). Again, while we recognize that not all payors will pay the same transportation rates, we used rates that we believe capture a reasonable representation, on average, of the rates paid by lessees.

Using the procedures in the December 1999 proposal, we estimate a 1998 revenue impact of:

• Category (1)	$1,638,053
• Category (2)	0
• Category (4)	9,277
Total	1,647,330

This revenue is shared 50% with the State of California.

Offshore Gulf of Mexico

The December 1999 proposal established the value of oil not sold at arm's length as either:

(1) The average of the daily mean spot price published in an MMS-approved publication—

(a) For the market center nearest the lease for crude oil similar in quality to the lessee's production, and

(b) For deliveries during the production month, or

(2) the gross proceeds received by the affiliate under an arm's-length contract.

The lessee would have to adjust the value for applicable location and quality differentials, and may adjust it for transportation costs.

There were three different spot prices published for Gulf of Mexico oil in 1998: Eugene Island (30° API, 1.61 percent sulfur), Heavy Louisiana Sweet (32° API, .3 percent sulfur), and Light Louisiana Sweet (37–38° API, .3 percent sulfur).

We believe that all large, independent producers/ marketers with no refinery capacity (Category 3) and small independent producers with no refinery capacity (Category 5) would value crude oil on the basis of arm's-length gross proceeds. Therefore, they were not included in the analysis. We examined the other three categories using the following procedure:

- We identified each individual area and block for each Federal offshore Gulf of Mexico lease.
- We assigned an oil type that most closely represented the oil and condensate specific to each area and block.
- The assigned oil type typically translated directly to the same spot price (e.g., Eugene Island Oil translates directly to the Eugene Island spot price), but in some limited cases, there was no spot price published for the identified oil type (e.g. Mars grade crude). In these cases, we used the spot oil with the characteristics that most closely matched the identified oil (e.g., we used the Eugene Island spot price for Mars oil).
- We calculated the average gravities by payor reported for each lease.
- We made gravity adjustments to the spot price using Equilon Oil Company's (Shell Oil Company in January 1998) offshore oil posted price adjustment scale in effect at the time of production.
- We deducted location differentials from the spot price for the actual movement of the oil from its first onshore location to the spot market. This value was based on FERC tariffs in effect for transport from major onshore gathering points to the spot market centers.
- We then compared the location- and quality-adjusted spot price to the value reported on Form MMS–2014 for each month in 1998. We then multiplied any difference by the royalty quantity for each lease and aggregated the differences.

Under the December 1999 proposal, we estimate a 1998 revenue gain of:

• Category (1)	$52,450,062
• Category (2):	4,658,893
• Category (4):	2,076,900
Total	59,185,855

In 1998, Texas and Louisiana received about 0.5 percent of the Federal oil royalties from the Gulf OCS—$4.9 million of $860 million total—under OCSLA section 8(g). Applying the same 0.5 percent to the above estimate equates to $295,929 in additional revenue for Texas and Louisiana.

Onshore New Mexico

For New Mexico, we split production into two subgroups: the Permian Basin and San Juan Basin. Since the production from New Mexico is roughly 60 percent sweet and 40 percent sour, we used the same 60/40 proportion to calculate a weighted average of the spot prices for West Texas Intermediate (at

Midland, Texas) and West Texas Sour. We then arrived at a monthly price at the lease by taking this weighted average spot value at Midland, Texas, less a charge for transportation specific to the production basin ($0.36 for Permian Basin Crude and $0.59 for San Juan Basin), and a gravity deduction based on 1998 Form MMS–2014 data. The transportation deductions came from the actual per-barrel tariff rates charged by pipelines in the area.

We compared (1) the monthly spot price at the lease to (2) the Category 1, 2, and 4 unit prices less any transportation allowances reported on Form MMS–2014. We multiplied this per-barrel incremental difference by the reported royalty quantity to compute the theoretical royalty gain or loss. We assumed there would be no revenue impact for the large independent producers/marketers without refinery capacity (Category 3) or the small independent producers without refinery capacity (Category 5) because they would pay on gross proceeds accruing from arm's-length sales.

Estimated 1998 revenue gains under the December 1999 proposal for onshore New Mexico are:

• Category (1)	$343,354
• Category (2)	185,883
• Category (4)	240,283
Total	769,520

This additional revenue would be shared 50% with New Mexico.

Rocky Mountain Region

We determined that calculating royalty value differences by State under the benchmark criteria for the RMR would not be meaningful due to lack of information. It is difficult to estimate what unit value a tendering program would have yielded, and we could not reasonably estimate how much production would be offered for sale. It is also difficult to determine the volume-weighted average price of a lessee's arm's-length sales and purchases from a field/area or whether that volume met the 50-percent threshold since we could not determine what sales or purchases were at arm's length. Also, we could not determine a location/quality differential from Cushing, Oklahoma, to the relevant fields/areas in each State due to lack of such transaction information.

In order to arrive at a fair market price that approximated arm's-length sales (i.e., attempting to mirror the valuation criteria), we utilized the monthly weighted average unit value per barrel for the large and small independent producers/marketers with no refining capacity (Categories 3 and 5). Those prices usually were higher than any of the three refiners' categories (1, 2, and 4) unit prices. We decided that this calculated arm's-length price would be a conservative, yet reasonable proxy for unit value payable under this final rule.

For Montana, North Dakota, and Utah we were unable to split the oil volumes into sweet and sour crudes (or Yellow and Black Wax for Utah), so we assumed that the lessees grouped into the five categories produced proportional volumes of the various crude types. Since we utilized unit prices that had already been adjusted for quality, we did not make any further quality adjustments.

For Wyoming, we split production into three distinct areas for review: Big Horn Basin, Green River Basin, and Powder River Basin (including the Wind River, Hanna, Laramie, and Denver-Julesberg Basins). The Powder River Basin contains roughly proportionate volumes of sweet and sour production. For Colorado, we split the analysis into the two dominant areas of production: Rangely and Denver-Julesburg.

Once we grouped the production into areas, we took the monthly weighted average unit price for the large and small independent producers/marketers with no refining capacity (Categories 3 and 5) and compared that price to unit prices of leases in the refiner categories (1, 2, and 4) as reported on Form MMS–2014. We multiplied the price difference per barrel by the royalty quantity to compute the royalty gains or losses. We assumed there would be no revenue impact for the large independent producers/marketers (Category 3) or the small independent producers (Category 5), because they would continue to pay on gross proceeds.

Estimated 1998 revenue gains under this final rule for the RMR (see Appendix A for actual State-by-State breakdown) are:

• Category (1)	$880,417
• Category (2)	196,127
• Category (4)	384,316
Total	$1,460,860

This amount would be shared 50% with the States.

Overall Increase in Revenue:

In summary, based on the 1998 comparison, we estimate the following additional revenues:

• Category 1, major integrated producers with refiner capacity	$59,675,723
• Category 2, large, independent producers with refiner capacity	5,282,150
• Category 4, small, independent producers with refiner capacity	2,837,205
• Grand Total	67,795,078

This estimate does not include estimated benefits to industry which bring the net increase in cost to industry to approximately $67.3 million.

Executive Order 12988

In accordance with Executive Order 12988, the Office of the Solicitor has determined that this rule will not unduly burden the judicial system and meets the civil justice reform requirements of sections 3(a) and 3(b)(2) of this Executive Order.

Paperwork Reduction Act

The collections of information associated with this final rule were approved by OMB on February 22, 2000 (OMB Control Number 1010–0136, expiration date February 28, 2003). We estimate that there will be 45 respondents who will submit 85 responses. The frequency of response varies by rulemaking section. We estimate that the total annual burden is 17,711.5 hours, and, using a cost of $50 per hour, the total annual cost is $885,575.

For estimating the burden on industry, we divided the information collection requirements of the rule into the five areas which are summarized below in table format with specific supporting details following each table.

a. Proper valuation of oil not sold at arm's-length.

30 CFR 206 subpart C	Reporting and recordkeeping requirements	Frequency	Number of respondents	Burden (in hours)	Annual burden hours
206.103	Calculate value of oil not sold at arm's-length..	Annually	45	Category 1–222.5 Category 2–116 Category 3–31.25	4,231.5

For the reporting requirements associated with Section 206.103, we estimate that there are 45 respondents (lessees of Federal oil leases) that will be required to perform certain calculations and adjustments. We estimate that the total initial burden for all lessees without arm's-length transactions is 4,231.5 hours at a cost of $211,575.

We anticipate that companies would have to sort through their exchange agreement contracts before the relevant ones can be compiled and the required information extracted and used in their royalty computations. We believe the final rule would impact approximately 45 Federal oil lessees that would be required to use index pricing. For purposes of estimating the burden impact of this rule, we have categorized these lessees into three categories:

Category 1 lessees are companies with over 30 million barrels of annual production (this included 13 Federal lessees from our impact analysis).

Category 2 lessees are companies with annual domestic production between 10 and 30 million barrels (this included four Federal lessees from our impact analysis).

Category 3 lessees are companies with less than 10 million barrels of annual domestic production (this included 28 Federal lessees from our impact analysis).

We estimate that Category 1 lessees each would have approximately 1,000 exchange agreement contracts to review annually to identify the relevant contracts needed for proper valuation under this final rule. Of those contracts, we estimate that each company would have to use 250 exchange agreements in its royalty reporting. We estimate that the reporting burden for a Category 1 company is 222.5 hours, including 80 hours to aggregate the exchange agreement contracts to a central location, 80 hours to sort and identify the relevant ones, and 62.5 additional hours to extract the relevant information and apply it in reporting royalties. We estimate the total reporting burden for the 13 Category 1 companies would be 2,892.5 hours (222.5 hours × 13 companies), including recordkeeping; using a per-hour cost of $50, the total cost would be $144,625.

We estimate that Category 2 lessees each would have approximately 250 exchange agreement contracts to review annually to identify the relevant contracts needed for valuation under this rule. Of those contracts, we estimate that each Category 2 company would have to use 63 exchange agreements. We estimate that the reporting burden for a Category 2 company would be 116 hours, including 60 hours to aggregate the exchange agreement contracts to a central location, 40 hours to sort them, and 16 additional hours to extract the relevant information and apply it in reporting royalties. For the four Category 2 companies, we estimate the total burden would be 464 hours (116 hours × 4 companies), including recordkeeping; using a per-hour cost of $50, the total cost would be $23,200.

We estimate that Category 3 lessees each would have approximately 50 exchange agreements to review annually to identify the relevant contracts needed for valuation under this rule. Of those contracts, we estimate that each Category 3 company would have to use 13 exchange agreements. We estimate that the burden for each Category 3 company would be 31.25 hours, including 20 hours to aggregate the exchange agreement contracts to a central location, eight hours to sort them, and 3.25 additional hours to extract the relevant information and apply it in reporting royalties. For the 28 Category 3 companies, we estimate that the burden would be 875 hours (31.25 hours × 28 companies), including recordkeeping; using a per-hour cost of $50, the total cost would be $43,750.

We expect the annual burden to decline somewhat as industry becomes more familiar with the proposed valuation requirements.

b. *Approval of benchmarks in the Rocky Mountain Region.*

30 CFR 206 subpart C	Reporting and recordkeeping requirements	Frequency	Number of responses	Burden (in hours)	Annual burden hours
206.103(b)(1)	Obtain MMS approval for tendering program ..	1–2 annually	2	400	800
206.103(b)(4)	Obtain MMS approval for alternative valuation methodology.	1–2 annually	2	400	800

For the reporting requirements related to MMS approval of using the benchmarks, we estimate that there will be two responses for each of the two reporting requirements. On occasion, they will be required to submit requests to us in writing.

We anticipate that a lessee will undertake the following four steps in the formulation of specifics surrounding a tendering program or alternate valuation strategy: (1) formulation of valuation methodology: 100 hours, (2) economic evaluation of methodology: 100 hours, (3) legal review of methodology: 150 hours, and (4) presentation to MMS: 50 hours, for a total of 400 hours.

We anticipate four requests a year for an annual burden of 1,600 hours, including recordkeeping. Based on a per-hour cost of $50, we estimate that the cost to industry is $80,000.

c. *Requirements related to requested valuation determinations and approval of location/quality adjustments from MMS.*

30 CFR 206 subpart C	Reporting and recordkeeping requirements	Frequency	Number of responses	Burden (in hours)	Annual burden hours
206.107(a)(1)–(6)	Request a value determination from MMS	1–2 monthly	8	330	2,640
206.112(b)	Request MMS approval for location/quality adjustment under non-arm's-length exchange agreements.	1–2 monthly	8	330	2,640

30 CFR 206 subpart C	Reporting and recordkeeping requirements	Frequency	Number of responses	Burden (in hours)	Annual burden hours
206.112(f)	Request MMS for location/quality adjustment when information is not available.	1–2 monthly	8	330	2,640

We anticipate that companies may request value determinations on how royalty statutes, regulations, administrative decisions, and policies apply to a specific set of facts. Their requests would have to: (1) Be in writing; (2) identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases; (3) completely explain all relevant facts. They must inform MMS of any changes to relevant facts that occur before MMS responds to their request; (4) include copies of all relevant documents; (5) provide their analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) suggest their proposed valuation method.

For the above written requests, we estimate that there will be eight responses annually for each of the reporting requirements. We estimate the annual burden for each of these is 2,640 hours, including recordkeeping. Based on a per-hour cost of $50, we estimate the cost to industry is $132,000. The total burden is estimated at 7,920 hours and $396,000.

d. *Requirements related to special requests due to unique circumstances.*

30 CFR 206 subpart C	Reporting and recordkeeping requirements	Frequency	Number of responses	Burden (in hours)	Annual burden hours
206.103(e)(1) and (2)(i)–(iv).	Obtain MMS approval to use value determined at refinery.	1–2 annually	2	330	660
206.110(b)(2)	Propose transportation cost allocation method to MMS when transporting more than one liquid product under an arm's-length contract.	1–2 annually	2	330	660
206.110(c)(1) and (3) ...	Propose transportation cost allocation method to MMS when transporting gaseous and liquid products under an arm's-length contract.	1–2 annually	2	330	660
206.111(g) and (g)(1) ...	Elect actual transportation cost method and depreciation method for non-arm's-length transportation allowances.	1–2 annually	2	330	660
206.111(i)(2)	Propose transportation cost allocation method to MMS when transporting more than one liquid product under a non-arm's-length contract.	1–2 annually	2	330	660
206.111(j)(1) and (3)	Propose transportation cost allocation method to MMS when transporting gaseous and liquid product under a non-arm's-length contract..	1–2 annually	2	330	660

There are several provisions in the rule that allow the lessee to propose some special consideration because the existing provisions of the rule may not precisely fit their situation. Like the written requests outlined above, their requests would have to: (1) Be in writing; (2) identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases; (3) completely explain all relevant facts. They must inform MMS of any changes to relevant facts that occur before MMS responds to their request; (4) include copies of all relevant documents; (5) provide their analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) suggest their proposed valuation method.

For the reporting requirements related to special requests because of unique circumstances, we estimate that there will be two responses for each of the six situations above. We estimate the annual burden for each of these is 660 hours, including recordkeeping. Based on a per-hour cost of $50, we estimate the cost to industry is $33,000. The total burden is estimated to be 3,960 hours and $198,000.

e. Currently-approved information collections.

30 CFR 206 Subpart D	Reporting and recordkeeping requirements	Frequency	Number of responses	Burden	Annual burden hours
206.105	Retain all records showing how value was determined.	Burden covered under OMB Control No. 1010–0061			
206.109(c)(2)	Request to exceed regulatory limit—Form MMS–4393.	Burden covered under OMB Control No. 1010–0095			
206.114 and 115(a)	Report a separate line for transportation allowances—Form MMS–2014.	Burden covered under OMB Control No. 1010–0022			
206.114 and 115(c)	Submit transportation documents upon MMS request.	Burden covered under OMB Control No. 1010–0061			

National Environmental Policy Act of 1969

We have determined that this rulemaking is not a major Federal action significantly affecting the quality of the human environment, and a detailed statement under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. § 4332(2)(C)) is not required.

List of Subjects 30 CFR Part 206

Coal, Continental shelf, Geothermal energy, Government contracts, Indians lands, Mineral royalties, Natural gas, Petroleum, Pubic lands-mineral resources, Reporting and recordkeeping requirements.

Dated: March 6, 2000.

Sylvia V. Baca,

Acting Assistant Secretary for Land and Minerals Management.

For the reasons given in the preamble, 30 CFR part 206 is amended as set forth below:

Part 206—Product Valuation

1. The authority citation for Part 206 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*; 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

2. Subpart C—Federal Oil is revised to read as follows:

Subpart C—Federal Oil

Sec.

§ 206.100 What is the purpose of this subpart?

(a) This subpart applies to all oil produced from Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS). It explains how you as a lessee must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If you are a designee and if you dispose of production on behalf of a lessee, the terms ''you'' and ''your'' in this subpart refer to you and not to the lessee. In this circumstance, you must determine and report royalty value for the lessee's oil by applying the rules in this subpart to your disposition of the lessee's oil.

(c) If you are a designee and only report for a lessee, and do not dispose of the lessee's production, references to ''you'' and ''your'' in this subpart refer to the lessee and not the designee. In this circumstance, you as a designee must determine and report royalty value for the lessee's oil by applying the rules in this subpart to the lessee's disposition of its oil.

(d) If the regulations in this subpart are inconsistent with:

(1) A Federal statute;

(2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation;

(3) A written agreement between the lessee and the MMS Director establishing a method to determine the value of production from any lease that MMS expects at least would approximate the value established under this subpart; or

(4) An express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(e) MMS may audit and adjust all royalty payments.

§ 206.101 What definitions apply to this subpart?

The following definitions apply to this subpart:

Affiliate means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that MMS may rebut.

(2) If there is ownership or common ownership of between 10 and 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, MMS will consider the following factors in determining whether there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors;

(ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: the percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;

(iii) Operation of a lease, plant, or other facility;

(iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

ANS means Alaska North Slope (ANS).

Area means a geographic region at least as large as the limits of an oil field, in which oil has similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

Audit means a review, conducted under generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases.

BLM means the Bureau of Land Management of the Department of the Interior.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without processing. Condensate is the mixture of liquid hydrocarbons resulting from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions, between two or more persons, that is enforceable by law and that with due consideration creates an obligation.

Designee means the person the lessee designates to report and pay the lessee's royalties for a lease.

Exchange agreement means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location. Exchange agreements may or may not specify prices for the oil involved. They frequently specify dollar amounts reflecting location, quality, or other differentials. Exchange agreements include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement. Examples of other types of exchange agreements include, but are not limited to, exchanges of produced oil for specific types of crude oil (e.g., West Texas Intermediate); exchanges of produced oil for other crude oil at other locations (Location Trades); exchanges of produced oil for other grades of oil (Grade Trades); and multi-party exchanges.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least the outermost boundaries of all oil and gas accumulations known within those reservoirs, vertically projected to the land surface. State oil and gas regulatory agencies usually name onshore fields and designate their official boundaries. MMS names and designates boundaries of OCS fields.

Gathering means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area that BLM or MMS approves for onshore and offshore leases, respectively.

Gross proceeds means the total monies and other consideration accruing for the disposition of oil produced. Gross proceeds also include, but are not limited to, the following examples:

(1) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government;

(2) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf;

(3) Reimbursements for harboring or terminaling fees;

(4) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation;

(5) Payments made to reduce or buy down the purchase price of oil to be produced in later periods, by allocating such payments over the production whose price the payment reduces and including the allocated amounts as proceeds for the production as it occurs; and

(6) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts.

Index pricing means using ANS crude oil spot prices, West Texas Intermediate (WTI) crude oil spot prices at Cushing, Oklahoma, or other appropriate crude oil spot prices for royalty valuation.

Index pricing point means the physical location where an index price is established in an MMS-approved publication.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of oil or gas—or the land area covered by that authorization, whichever the context requires.

Lessee means any person to whom the United States issues an oil and gas lease, an assignee of all or a part of the record title interest, or any person to whom operating rights in a lease have been assigned.

Location differential means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

Market center means a major point MMS recognizes for oil sales, refining, or transshipment. Market centers generally are locations where MMS-approved publications publish oil spot prices.

Marketable condition means oil sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area.

MMS-approved publication means a publication MMS approves for determining ANS spot prices, other spot prices, or location differentials.

Netting means reducing the reported sales value to account for transportation instead of reporting a transportation allowance as a separate entry on Form MMS–2014.

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs, remains liquid at atmospheric pressure after passing through surface separating facilities, and is marketed or used as a liquid. Condensate recovered in lease separators or field facilities is oil.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Quality differential means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

Rocky Mountain Region means the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and other oil-producing fields in the ''Four Corners'' area that lie within Colorado and Utah.

Sale means a contract between two persons where:

(1) The seller unconditionally transfers title to the oil to the buyer and does not retain any related rights such

as the right to buy back similar quantities of oil from the buyer elsewhere;

(2) The buyer pays money or other consideration for the oil; and

(3) The parties' intent is for a sale of the oil to occur.

Spot price means the price under a spot sales contract where:

(1) A seller agrees to sell to a buyer a specified amount of oil at a specified price over a specified period of short duration;

(2) No cancellation notice is required to terminate the sales agreement; and

(3) There is no obligation or implied intent to continue to sell in subsequent periods.

Tendering program means a producer's offer of a portion of its crude oil produced from a field or area for competitive bidding, regardless of whether the production is offered or sold at or near the lease or unit or away from the lease or unit.

Trading month means the span of time during which crude oil trading occurs and spot prices are determined, generally for deliveries of production in the following calendar month. For example, for ANS spot prices, the trading month includes all business days in the calendar month. For other spot prices, for example, the trading month may include the span of time from the 26th of the previous month through the 25th of the current month.

Transportation allowance means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

§ 206.102 How do I calculate royalty value for oil that I or my affiliate sell(s) under an arm's-length contract?

(a) The value of oil under this section is the gross proceeds accruing to the seller under the arm's-length contract, less applicable allowances determined under §§ 206.110 or 206.111. This value does not apply if you exercise an option to use a different value provided in paragraph (d)(1) or (d)(2)(i) of this section, or if one of the exceptions in paragraph (c) of this section applies. Use this paragraph (a) to value oil that:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract, unless you exercise the option provided in paragraph (d)(2)(i) of this section.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for each contract for the sale of oil produced from that lease.

(c) This paragraph contains exceptions to the valuation rule in paragraph (a) of this section. Apply these exceptions on an individual contract basis.

(1) In conducting reviews and audits, if MMS determines that any arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, MMS may require that you value the oil sold under that contract either under § 206.103 or at the total consideration received.

(2) You must value the oil under § 206.103 if MMS determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.

(B) The fact that the price received by the seller under an arm's length contract is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil from the lease.

(d)(1) If you enter into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, and following the exchange(s) you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you may use either § 206.102(a) or § 206.103 to value your production for royalty purposes.

(i) If you use § 206.102(a), your gross proceeds are the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s). You must adjust your gross proceeds for any location or quality differential, or other adjustments, you received or paid under the arm's-length exchange agreement(s). If MMS determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, MMS may require you to value the oil under § 206.103. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(ii) When you elect under § 206.102(d)(1) to use § 206.102(a) or § 206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) sold under arm's-length contracts following arm's-length exchange agreements. You may not change your election more often than once every 2 years.

(2)(i) If you sell or transfer your oil production to your affiliate and that affiliate or another affiliate then sells the oil under an arm's-length contract, you may use either § 206.102(a) or § 206.103 to value your production for royalty purposes.

(ii) When you elect under § 206.102(d)(2)(i) to use § 206.102(a) or § 206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that your affiliates resell at arm's length. You may not change your election more often than once every 2 years.

(e) If you value oil under paragraph (a) of this section:

(1) MMS may require you to certify that your or your affiliate's arm's-length contract provisions include all of the consideration the buyer must pay, either directly or indirectly, for the oil.

(2) You must base value on the highest price the seller can receive through legally enforceable claims under the contract.

(i) If the seller fails to take proper or timely action to receive prices or benefits it is entitled to, you must pay royalty at a value based upon that obtainable price or benefit. But you will owe no additional royalties unless or until the seller receives monies or consideration resulting from the price increase or additional benefits, if:

(A) The seller makes timely application for a price increase or benefit allowed under the contract;

(B) The purchaser refuses to comply; and (C) The seller takes reasonable documented measures to force purchaser compliance.

(ii) Paragraph (e)(2)(i) of this section will not permit you to avoid your royalty payment obligation where a purchaser fails to pay, pays only in part, or pays late. Any contract revisions or amendments that reduce prices or benefits to which the seller is entitled must be in writing and signed by all parties to the arm's-length contract.

§ 206.103 How do I value oil that is not sold under an arm's-length contract?

This section explains how to value oil that you may not value under § 206.102 or that you elect under § 206.102(d) to value under this section. First determine whether paragraph (a), (b), or (c) of this section applies to production from your lease, or whether you may apply paragraph (d) or (e) with MMS approval.

(a) *Production from leases in California or Alaska.* Value is the average of the daily mean ANS spot prices published in any MMS-approved publication during the trading month most concurrent with the production month. (For example, if the production month is June, compute the average of the daily mean prices using the daily ANS spot prices published in the MMS-approved publication for all the business days in June.)

(1) To calculate the daily mean spot price, average the daily high and low prices for the month in the selected publication.

(2) Use only the days and corresponding spot prices for which such prices are published.

(3) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 206.112.

(4) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options for valuing your production under different factual situations.

(1) If you have an MMS-approved tendering program, value your oil under paragraph (b)(2) of this section. If you do not have an MMS-approved tendering program, you may value your oil under either paragraph (b)(3) or paragraph (b)(4) of this section.

(i) You must apply the same subparagraph of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that you cannot value under § 206.102 or that you elect under § 206.102(d) to value under this section.

(ii) After you select either paragraph (b)(3) or (b)(4) of this section, you may not change to the other method more often than once every 2 years, unless the method you have been using is no longer applicable and you must apply one of the other paragraphs. If you change methods, you must begin a new 2-year period.

(2) If you have an MMS-approved tendering program, the value of production from leases in the area the tendering program covers is the highest winning bid price for tendered volumes.

(i) You must offer and sell at least 30 percent of your production from both Federal and non-Federal leases in that area under your tendering program.

(ii) You also must receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

(iii) MMS will provide additional criteria for approval of a tendering program in its ''Oil and Gas Payor Handbook.''

(3) Value is the volume-weighted average gross proceeds accruing to the seller under your and your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month. The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliates' production from both Federal and non-Federal leases in the same field or area during that month. Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliates' arms-length purchases or sales to the same gravity as that of the oil produced from the lease.

(4) Value is the average of the daily mean spot prices published in any MMS-approved publication for WTI crude at Cushing, Oklahoma, during the trading month most concurrent with the production month. (For example, if the production month is June and the trading month is May 26—June 25, compute the average of the daily mean prices using the daily Cushing spot prices published in the MMS-approved publication for all the business days between and including May 26 and June 25.)

(i) Calculate the daily mean spot price by averaging the daily high and low prices for the period in the selected publication.

(ii) Use only the days and corresponding spot prices for which such prices are published.

(iii) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 206.112.

(iv) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(5) If you demonstrate to MMS's satisfaction that paragraphs (b)(2) through (b)(4) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the MMS Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.*

(1) Value is the average of the daily mean spot prices published in any MMS-approved publication:

(i) For the market center nearest your lease for crude oil similar in quality to that of your production (for example, at the St. James, Louisiana, market center, spot prices are published for both Light Louisiana Sweet and Eugene Island crude oils—their quality specifications differ significantly); and

(ii) During the trading month most concurrent with the production month. (For example, if the production month is June and the trading month is May 26–June 25, compute the average of the daily mean prices using the daily spot prices published in the MMS-approved publication for all the business days between and including May 26 and June 25 for the applicable market center.)

(2) Calculate the daily mean spot price by averaging the daily high and low prices for the period in the selected publication. Use only the days and corresponding spot prices for which such prices are published. You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 206.112.

(3) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(d) *Unavailable or unreasonable index prices.* If MMS determines that any of the index prices referenced in paragraphs (a), (b), and (c) of this section are unavailable or no longer represent reasonable royalty value, in any particular case, MMS may establish reasonable royalty value based on other relevant matters.

(e) *Production delivered to your refinery and index price is unreasonable.*

(1) Instead of valuing your production under paragraph (a), (b), or (c) of this section, you may apply to the MMS Director to establish a value representing the market at the refinery if:

(i) You transport your oil directly to your or your affiliate's refinery, or exchange your oil for oil delivered to your or your affiliate's refinery; and

(ii) You must value your oil under this section at an index price; and

(iii) You believe that use of the index price is unreasonable.

(2) You must provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to:

(i) Costs of acquiring other crude oil at or for the refinery;

(ii) How adjustments for quality, location, and transportation were factored into the price paid for other oil;

(iii) Volumes acquired for and refined at the refinery; and

(iv) Any other appropriate evidence or documentation that MMS requires.

(3) If the MMS Director establishes a value representing market value at the refinery, you may not take an allowance against that value under § 206.112(b) unless it is included in the Director's approval.

§ 206.104 What index price publications are acceptable to MMS?

(a) MMS periodically will publish in the **Federal Register** a list of acceptable index price publications based on certain criteria, including but not limited to:

(1) Publications buyers and sellers frequently use;

(2) Publications frequently mentioned in purchase or sales contracts;

(3) Publications that use adequate survey techniques, including development of spot price estimates based on daily surveys of buyers and sellers of ANS and other crude oil; and

(4) Publications independent from MMS, other lessors, and lessees.

(b) Any publication may petition MMS to be added to the list of acceptable publications.

(c) MMS will reference the tables you must use in the publications to determine the associated index prices.

(d) MMS may revoke its approval of a particular publication if it determines that the prices published in the publication do not accurately represent spot market values.

§ 206.105 What records must I keep to support my calculations of value under this subpart?

If you determine the value of your oil under this subpart, you must retain all data relevant to the determination of royalty value.

(a) You must be able to show:

(1) How you calculated the value you reported, including all adjustments for location, quality, and transportation, and

(2) How you complied with these rules.

(b) Recordkeeping requirements are found at part 207 of this chapter.

(c) MMS may review and audit your data, and MMS will direct you to use a different value if it determines that the reported value is inconsistent with the requirements of this subpart.

§ 206.106 What are my responsibilities to place production into marketable condition and to market production?

You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.

§ 206.107 How do I request a value determination?

(a) You may request a value determination from MMS regarding any Federal lease oil production. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases;

(3) Completely explain all relevant facts. You must inform MMS of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed valuation method.

(b) MMS will reply to requests expeditiously. MMS may either:

(1) Issue a value determination signed by the Assistant Secretary, Land and Minerals Management; or

(2) Issue a value determination by MMS; or

(3) Inform you in writing that MMS will not provide a value determination. Situations in which MMS typically will not provide any value determination include, but are not limited to:

(i) Requests for guidance on hypothetical situations; and

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A value determination signed by the Assistant Secretary, Land and Minerals Management, is binding on both you and MMS until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a value determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, pay late payment interest under 30 CFR 218.54.

(3) A value determination signed by the Assistant Secretary is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) A value determination issued by MMS is binding on MMS and delegated States with respect to the specific situation addressed in the determination unless the MMS (for MMS-issued value determinations) or the Assistant Secretary modifies or rescinds it.

(1) A value determination by MMS is not an appealable decision or order under 30 CFR part 290 subpart B.

(2) If you receive an order requiring you to pay royalty on the same basis as the value determination, you may appeal that order under 30 CFR part 290 subpart B.

(e) In making a value determination, MMS or the Assistant Secretary may use any of the applicable valuation criteria in this subpart.

(f) A change in an applicable statute or regulation on which any value determination is based takes precedence over the value determination, regardless of whether the MMS or the Assistant Secretary modifies or rescinds the value determination.

(g) The MMS or the Assistant Secretary generally will not retroactively modify or rescind a value determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) MMS may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 206.108.

§ 206.108 Does MMS protect information I provide?

Certain information you submit to MMS regarding valuation of oil, including transportation allowances, may be exempt from disclosure. To the extent applicable laws and regulations permit, MMS will keep confidential any data you submit that is privileged, confidential, or otherwise exempt from disclosure. All requests for information must be submitted under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§ 206.109 When may I take a transportation allowance in determining value?

(a) *Transportation allowances permitted when value is based on gross proceeds.* MMS will allow a deduction for the reasonable, actual costs to transport oil from the lease to the point off the lease under §§ 206.110 or 206.111, as applicable. This paragraph applies when:

(1) You value oil under § 206.102 based on gross proceeds from a sale at a point off the lease, unit, or communitized area where the oil is produced, and

(2) The movement to the sales point is not gathering.

(b) *Transportation allowances and other adjustments that apply when value is based on index pricing.*

If you value oil using an index price under § 206.103, MMS will allow a deduction for certain location/quality adjustments and certain costs associated with transporting oil as provided under § 206.112.

(c) *Limits on transportation allowances.*

(1) Except as provided in paragraph (c)(2) of this section, your transportation allowance may not exceed 50 percent of the value of the oil as determined under § 206.102 or § 206.103 of this subpart. You may not use transportation costs incurred to move a particular volume of production to reduce royalties owed on production for which those costs were not incurred.

(2) You may ask MMS to approve a transportation allowance in excess of the limitation in paragraph (c)(1) of this section. You must demonstrate that the transportation costs incurred were reasonable, actual, and necessary. Your application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination. You may never reduce the royalty value of any production to zero.

(d) *Allocation of transportation costs.* You must allocate transportation costs among all products produced and transported as provided in §§ 206.110 and 206.111. You must express transportation allowances for oil as dollars per barrel.

(e) *Liability for additional payments.* If MMS determines that you took an excessive transportation allowance, then you must pay any additional royalties due, plus interest under 30 CFR 218.54. You also could be entitled to a credit with interest under applicable rules if you understated your transportation allowance. If you take a deduction for transportation on Form MMS–2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate entry, MMS may assess you an amount under § 206.116.

§ 206.110 How do I determine a transportation allowance under an arm's-length transportation contract?

(a) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting oil under that contract, except as provided in paragraphs (a)(1) and (a)(2) of this section and subject to the limitation in § 206.109(c). You must be able to demonstrate that your contract is arm's length. You do not need MMS approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(1) If MMS determines that the contract reflects more than the consideration actually transferred either directly or indirectly from you or your affiliate to the transporter for the transportation, MMS may require that you calculate the transportation allowance under § 206.111.

(2) You must calculate the transportation allowance under § 206.111 if MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) MMS will not use this provision to simply substitute its judgment of the reasonable oil transportation costs incurred by you or your affiliate under an arm's-length transportation contract.

(B) The fact that the cost you or your affiliate incur in an arm's length transaction is higher than other measures of transportation costs, such as rates paid by others in the field or area, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that you or your affiliate acted unreasonably or in bad faith in transporting oil from the lease.

(b) If your arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then you must allocate the total transportation costs to each of the liquid products transported.

(1) Your allocation must use the same proportion as the ratio of the volume of each product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(2) You may not claim an allowance for the costs of transporting lease production that is not royalty-bearing.

(3) You may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method unless it is not consistent with the purposes of the regulations in this subpart.

(c) If your arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, then you must propose an allocation procedure to MMS.

(1) You may use your proposed procedure to calculate a transportation allowance until MMS accepts or rejects your cost allocation. If MMS rejects your cost allocation, you must amend your Form MMS–2014 for the months that you used the rejected method and pay any additional royalty and interest due.

(2) You must submit your initial proposal, including all available data, within 3 months after first claiming the allocated deductions on Form MMS–2014.

(d) If your payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, you must convert whatever consideration is paid to a dollar-value equivalent.

(e) If your arm's-length sales contract includes a provision reducing the contract price by a transportation factor, do not separately report the transportation factor as a transportation allowance on Form MMS–2014.

(1) You may use the transportation factor in determining your gross proceeds for the sale of the product.

(2) You must obtain MMS approval before claiming a transportation factor in excess of 50 percent of the base price of the product.

§ 206.111 How do I determine a transportation allowance under a non-arm's-length transportation arrangement?

(a) If you or your affiliate have a non-arm's-length transportation contract or no contract, including those situations where you or your affiliate perform your own transportation services, calculate your transportation allowance based on your or your affiliate's reasonable, actual transportation costs using the procedures provided in this section.

(b) Base your transportation allowance for non-arm's-length or no-contract situations on your or your affiliate's actual costs for transportation during the reporting period, including:

(1) Operating and maintenance expenses under paragraphs (d) and (e) of this section;

(2) Overhead under paragraph (f) of this section;

(3) Depreciation under paragraphs (g) and (h) of this section;

(4) A return on undepreciated capital investment under paragraph (i) of this section; and

(5) Once the transportation system has been depreciated below ten percent of total capital investment, a return on ten percent of total capital investment under paragraph (j) of this section.

(c) Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(d) Allowable operating expenses include:

(i) Operations supervision and engineering;

(ii) Operations labor;

(iii) Fuel;

(iv) Utilities;

(v) Materials;

(vi) Ad valorem property taxes;

(vii) Rent;

(viii) Supplies; and

(ix) Any other directly allocable and attributable operating expense which you can document.

(e) Allowable maintenance expenses include:

(i) Maintenance of the transportation system;

(ii) Maintenance of equipment;

(iii) Maintenance labor; and

(iv) Other directly allocable and attributable maintenance expenses which you can document.

(f) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(g) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit-of-production method. After you make an election, you may not change methods without MMS approval. You may not depreciate equipment below a reasonable salvage value.

(h) This paragraph describes the basis for your depreciation schedule.

(1) If you or your affiliate own a transportation system on June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs for production after June 1, 2000, on your total capital investment in the system (including your original purchase price or construction cost and subsequent reinvestment).

(2) If you or your affiliate purchased the transportation system at arm's length before June 1, 2000, you must incorporate depreciation on the schedule based on your purchase price (and subsequent reinvestment) into your transportation allowance calculations for production after June 1, 2000, beginning at the point on the depreciation schedule corresponding to that date. You must prorate your depreciation for calendar year 2000 by claiming part-year depreciation for the period from June 1, 2000 until December 31, 2000. You may not adjust your transportation costs for production before June 1, 2000, using the depreciation schedule based on your purchase price.

(3) If you are the original owner of the transportation system on June 1, 2000, or if you purchased your transportation system before March 1, 1988, you must continue to use your existing depreciation schedule in calculating actual transportation costs for production in periods after June 1, 2000.

(4) If you or your affiliate purchase a transportation system at arm's length from the original owner after June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs on your total capital investment in the system (including your original purchase price and subsequent reinvestment). You must prorate your depreciation for the year in which you or your affiliate purchased the system to reflect the portion of that year for which you or your affiliate own the system.

(5) If you or your affiliate purchase a transportation system at arm's length after June 1, 2000, from anyone other than the original owner, you must assume the depreciation schedule of the person who owned the system on June 1, 2000.

(i)(1) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transportation allowance by the rate of return provided in paragraph (i)(2) of this section.

(2) The rate of return is the industrial bond yield index for Standard and Poor's BBB rating. Use the monthly average rate published in ''Standard and Poor's Bond Guide'' for the first month of the reporting period for which the allowance applies. Calculate the rate at the beginning of each subsequent transportation allowance reporting period.

(j)(1) After a transportation system has been depreciated at or below a value equal to ten percent of your total capital investment, you may continue to include in the allowance calculation a cost equal to ten percent of your total capital investment in the transportation system multiplied by a rate of return under paragraph (i)(2) of this section.

(2) You may apply this paragraph to a transportation system that before June 1, 2000, was depreciated at or below a value equal to ten percent of your total capital investment.

(k) Calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocate costs consistently and equitably to each of the liquid products transported. Your allocation must use the same proportion as the ratio of the volume of each liquid product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method if it is consistent with the purposes of the regulations in this subpart.

(l)(1) Where you transport both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to MMS.

(2) You may use your proposed procedure to calculate a transportation allowance until MMS accepts or rejects your cost allocation. If MMS rejects your cost allocation, you must amend your Form MMS–2014 for the months that you used the rejected method and pay any additional royalty and interest due.

(3) You must submit your initial proposal, including all available data, within 3 months after first claiming the allocated deductions on Form MMS–2014.

§ 206.112 What adjustments and transportation allowances apply when I value oil using index pricing?

When you use index pricing to calculate the value of production under § 206.103, you must adjust the index price for location and quality differentials and you may adjust it for certain transportation costs, as specified in this section.

(a) If you dispose of your production under one or more arm's-length exchange agreements, then each of the conditions in this paragraph applies.

(1) You must adjust the index price for location/quality differentials. You must determine those differentials from each of your arm's-length exchange agreements applicable to the exchanged oil.

(i) Therefore, for example, if you exchange 100 barrels of production from a given lease under two separate arm's-length exchange agreements for 60 barrels and 40 barrels respectively, separately determine the location/quality differential under each of those exchange agreements, and apply each differential to the corresponding index price.

(ii) As another example, if you produce 100 barrels and exchange that 100 barrels three successive times under arm's-length agreements to obtain oil at a final destination, total the three adjustments from those exchanges to determine the adjustment under this subparagraph. (If one of the three exchanges was not at arm's length, you must request MMS approval under paragraph (b) of this section for the location/quality adjustment for that exchange to determine the total location/quality adjustment for the three exchanges.) You also could have a combination of these examples.

(2) You may adjust the index price for actual transportation costs, determined under § 206.110 or § 206.111:

(i) From the lease to the first point where you give your oil in exchange; and

(ii) From any intermediate point where you receive oil in exchange to another intermediate point where you give the oil in exchange again; and

(iii) From the point where you receive oil in exchange and transport it without further exchange to a market center, or to a refinery that is not at a market center.

(b) For non-arm's-length exchange agreements, you must request approval from MMS for any location/quality adjustment.

(c) If you transport lease production directly to a market center or to an alternate disposal point (for example, your refinery), you may adjust the index price for your actual transportation costs, determined under § 206.110 or § 206.111.

(d) If you adjust for location/quality or transportation costs under paragraphs (a), (b), or (c) of this section, also adjust the index price for quality based on premia or penalties determined by pipeline quality bank specifications at intermediate commingling points or at the market center. Make this adjustment only if and to the extent that such adjustments were not already included in the location/quality differentials determined from your arm's-length exchange agreements.

(e) For leases in the Rocky Mountain Region, for purposes of this section, the term ''market center'' means Cushing, Oklahoma, unless MMS specifies otherwise through notice published in the **Federal Register**.

(f) If you cannot determine your location/quality adjustment under paragraph (a) or (c) of this section, you must request approval from MMS for any location/quality adjustment.

(g) You may not use any transportation or quality adjustment that duplicates all or part of any other adjustment that you use under this section.

§ 206.113 How will MMS identify market centers?

MMS periodically will publish in the **Federal Register** a list of market centers. MMS will monitor market activity and, if necessary, add to or modify the list of market centers and will publish such modifications in the **Federal Register**. MMS will consider the following factors and conditions in specifying market centers:

(a) Points where MMS-approved publications publish prices useful for index purposes;

(b) Markets served;

(c) Input from industry and others knowledgeable in crude oil marketing and transportation;

(d) Simplification; and

(e) Other relevant matters.

§ 206.114 What are my reporting requirements under an arm's-length transportation contract?

You or your affiliate must use a separate entry on Form MMS–2014 to notify MMS of an allowance based on transportation costs you or your affiliate incur. MMS may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Recordkeeping requirements are found at part 207 of this chapter.

§ 206.115 What are my reporting requirements under a non-arm's-length transportation arrangement?

(a) You or your affiliate must use a separate entry on Form MMS–2014 to notify MMS of an allowance based on transportation costs you or your affiliate incur.

(b) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable oil transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems. Section 206.117 will apply when you amend your report based on your actual costs.

(c) MMS may require you or your affiliate to submit all data used to calculate the allowance deduction. Recordkeeping requirements are found at part 207 of this chapter.

§ 206.116 What interest and assessments apply if I improperly report a transportation allowance?

(a) If you or your affiliate net a transportation allowance rather than report it as a separate entry against the royalty value on Form MMS–2014, you will be assessed an amount up to 10 percent of the netted allowance, not to exceed $250 per lease selling arrangement per sales period.

(b) If you or your affiliate deduct a transportation allowance on Form MMS–2014 that exceeds 50 percent of the value of the oil transported without obtaining MMS's prior approval under § 206.109, you must pay interest on the excess allowance amount taken from the date that amount is taken to the date you or your affiliate file an exception request that MMS approves. If you do not file an exception request, or if MMS does not approve your request, you must pay interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

§ 206.117 What reporting adjustments must I make for transportation allowances?

(a) If your or your affiliate's actual transportation allowance is less than the amount you claimed on Form MMS–2014 for each month during the allowance reporting period, you must pay additional royalties plus interest computed under 30 CFR 218.54 from the date you took the deduction to the date you repay the difference.

(b) If the actual transportation allowance is greater than the amount you claimed on Form MMS–2014 for any month during the allowance form reporting period, you are entitled to a credit plus interest under applicable rules.

§ 206.118 Are actual or theoretical losses permitted as part of a transportation allowance?

You are allowed a deduction for oil transportation which results from payments that you make (either volumetric or for value) for actual or theoretical losses only under an arm's-length contract. You may not take such a deduction under a non-arm's-length contract.

§ 206.119 How are royalty quantity and quality determined?

(a) Compute royalties based on the quantity and quality of oil as measured at the point of settlement approved by BLM for onshore leases or MMS for offshore leases.

(b) If the value of oil determined under this subpart is based upon a quantity or quality different from the quantity or quality at the point of royalty settlement approved by the BLM for onshore leases or MMS for offshore leases, adjust the value for those differences in quantity or quality.

(c) You may not claim a deduction from the royalty volume or royalty value for actual or theoretical losses except as provided in § 206.118. Any actual loss that you may incur before the royalty settlement metering or measurement point is not subject to royalty if BLM or MMS, as appropriate, determines that the loss is unavoidable.

(d) Except as provided in paragraph (b) of this section, royalties are due on 100 percent of the volume measured at the approved point of royalty settlement. You may not claim a reduction in that measured volume for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either before or after the approved point of royalty settlement.

§ 206.120 How are operating allowances determined?

MMS may use an operating allowance for the purpose of computing payment obligations when specified in the notice of sale and the lease. MMS will specify the allowance amount or formula in the notice of sale and in the lease agreement.

§ 206.121 Is there any grace period for reporting and paying royalties after this subpart becomes effective?

You may adjust royalties reported and paid for the three production months beginning June 1, 2000, without liability for late payment interest. This section applies only if the adjustment results from systems changes needed to comply with new requirements imposed under this subpart that were not requirements under the predecessor rule.

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