Analysis of Alternatives

Affected operators and helicopter air tour pilots have petitioned the FAA to amend SFAR 71. They argue that SFAR 71's 1500-foot minimum altitude requirement is ''cumbersome and lacks flexibility in dynamic circumstances.'' The petitioners also maintain that allowing air tour flights as low as 300 feet above the surface would make SFAR 71 safer in certain circumstances.

The FAA has considered the petitioners' views in formulating this proposed rule. The issues raised are similar to comments received by the agency during the three SFAR rulemaking preceding this proposed rule. The FAA concludes that 1,500 feet provides a pilot with more distance, and, thus time, to avoid an accident or to deal with an error. An altitude of 300 feet provides 80 percent less distance and thus, much less reaction time.

Affordability Analysis

The FAA lacks reliable revenue and profit data on the individual entities affected by this rule, but the estimated cost to each of these small entities is approximately 5.3 percent of the average revenue of non-scheduled air transportation firms with fewer than 500 employees based on the SBA's Census data. Hawaii air tour operators have been subject to the proposed provisions of this rule since 1994. While there are fewer operators today than in 1994, the cause cannot be directly attributed to SFAR 71 but rather, the vagaries and nature of the tourism market. New air tour operators have entered the market after making the business decision to accept the provisions of this rule. The FAA invites comment on the potential impact of the proposal on revenues and profits.

Business Closure Analysis

The FAA estimates that none of the operators currently providing air tour flights would elect to stop providing the service. These operators have been complying with these provisions since 1994.

Disproportionality Analysis

All Hawaiian entities in the air tour market are small. Accordingly, the costs imposed by this proposal would be borne almost entirely by small businesses. The estimated costs are proportional to the frequency of operations and thus the burden is not disproportionate. Air tour safety in Hawaii has been significantly improved, and the FAA believes that the only way to continue this is to maintain these higher standards on these entities.

Key Assumptions Analysis

The FAA has made several conservative assumptions in this analysis, which may have resulted in an overestimate of the costs of the proposal. For example, the FAA assumes that the pilot in command would conduct all pre-flight briefings but the provision only requires the pilot to ''ensure that each passenger has been briefed''. The briefing could be recorded or provided by a lower paid employee. Also, the helicopter life preserver costs may be overestimated since there is a voluntary industry standard to which 13 helicopter tour operators subscribe that requires occupants to wear a personal flotation device.

Issued in Washington, DC, on August 18, 2003.

Donald P. Byrne,

Assistant Chief Counsel.

[FR Doc. 03–21423 Filed 8–18–03; 12:19 pm]

BILLING CODE 4910–13–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[REG–108676–03]

RIN 1545–BC00

Distributions of Interest in a Loss Corporation From Qualified Trust; Correction

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Correction to a notice of proposed rulemaking; by cross-reference to temporary regulations and notice of public hearing.

SUMMARY: This document contains regulations under section 382 of the Internal Revenue Code of 1986. The proposed regulations affect loss corporations and provide guidance on whether a loss corporation has an ownership change where a qualified trust described in section 401(a) distributes an ownership interest in an entity.

FOR FURTHER INFORMATION CONTACT: Martin Huck at (202) 622–7750 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background

The proposed regulations that are the subject of these corrections are under section 382 of the Internal Revenue Code.

Need for Correction

As published, this notice of proposed rulemaking by cross-reference to temporary regulations and notice of public hearing contains errors that may prove to be misleading and are in need of clarification.

Correction of Publication

Accordingly, the publication of the notice of proposed rulemaking by cross-reference to temporary regulations and notice of public hearing (REG–108676–03), which is the subject of FR. Doc. 03–16230, is corrected as follows:

1. On page 38247, column 3, in the preamble, under the subject heading **ADDRESSES**, line 3, the language ''5226, Internal Revenue Service, POB'' is corrected to read ''5207, Internal Revenue Service, POB''.

2. On page 38248, column 1, in the preamble, under the subject heading **FOR FURTHER INFORMATION CONTACT**, line 5, the language ''Treena Garrett, (202) 622–7180 (not toll-'' is corrected to read ''Treena Garrett, (202) 622–3401 (not toll-''.

LaNita Van Dyke,

Acting Chief, Regulations Unit, Associate Chief Counsel (Procedure and Administration).

[FR Doc. 03–21356 Filed 8–19–03; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 206 and 210

RIN 1010–AD04

Federal Oil Valuation

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Proposed rule.

SUMMARY: The MMS is proposing to amend the existing regulations governing the valuation of crude oil produced from Federal leases for royalty purposes, and related provisions governing the reporting thereof. The current regulations became effective on June 1, 2000.

Experience thus far has shown that the 2000 rules have generally served both MMS (and the states who cooperate with MMS in auditing Federal leases) and the producing industry well. However, in continuing to evaluate the effectiveness and efficiency of its rules, MMS has identified certain issues that warrant further proposal and public comment. These issues concern primarily which published market

prices are most appropriate to value crude oil not sold at arm's length and what transportation deductions should be allowed. Experience thus far with the 2000 rules, some years of experience in taking and selling royalty-in-kind oil, and information learned during litigation challenging the 2000 rules indicate a potential for improving those rules in some respects.

DATES: Comments must be submitted on or before September 19, 2003.

ADDRESSES: Address your comments, suggestions, or objections regarding this proposed rule to:

By regular U.S. mail. Minerals Management Service, Minerals Revenue Management, Records and Information Management Team, P.O. Box 25165, MS 320B2, Denver, Colorado 80225–0165; or

By overnight mail or courier. Minerals Management Service, Minerals Revenue Management, Building 85, Room A–614, Denver Federal Center, Denver, Colorado 80225; or

By e-mail. *mrm.comments@mms.gov.* Please submit Internet comments as an ASCII file and avoid the use of special characters and any form of encryption. Also, please include ''Attn: RIN 1010–AD04'' and your name and return address in your Internet message. If you do not receive a confirmation that we have received your Internet message, call the contact person listed below.

Address your comments on the information collection requirements in this proposed rule by either fax (202) 395–6566 or e-mail (*OIRA_docket@omb.eop.gov*) to the Office of Information and Regulatory Affairs, OMB, Attention: Desk Officer for the Department of the Interior (OMB Control Number 1010–NEW). Send copies of your comments to Sharron L. Gebhardt, Regulatory Specialist, Records and Information Management Team, Minerals Management Service, Minerals Revenue Management, P.O. Box 25165, MS 320B2, Denver, Colorado 80225. If you use an overnight courier service, the MMS courier address is Building 85, Room A–614, Denver Federal Center, Denver, Colorado 80225. You may also e-mail your comments to us at *mrm.comments@mms.gov.* Include the title of the information collection and the OMB Control number in the ''Attention'' line of your comment. Also include your name and return address. Submit electronic comments as an ASCII file avoiding the use of special characters and any form of encryption. If you do not receive a confirmation that we have received your e-mail, contact Ms. Gebhardt at (303) 231–3211.

FOR FURTHER INFORMATION CONTACT: Sharron L. Gebhardt, Regulatory Specialist, Records and Information Management Team, Minerals Revenue Management, MMS, telephone (303) 231–3316, fax (303) 231–3385, or e-mail *sharron.gebhardt@mms.gov.* The principal authors of this rule are Geoffrey Heath of the Office of the Solicitor and David A. Hubbard of Minerals Revenue Management, MMS, Department of the Interior.

SUPPLEMENTARY INFORMATION:

I. Background

The MMS is proposing to amend the existing regulations at 30 CFR 206.100 *et seq.*, governing the valuation of crude oil produced from Federal leases for royalty purposes, and related provisions governing the reporting thereof. The current regulations became effective on June 1, 2000. The producing industry filed a lawsuit challenging several of the provisions in the 2000 rule. *Independent Petroleum Association of America* v. *Baca, Civil No. 00–761 (RCL) (D.D.C.),* and *American Petroleum Institute* v. *Baca, Civil No. 00–887 (RCL) (D.D.C.) (consolidated).* That lawsuit is still pending.

MMS conducted four public workshops on March 4–6, 2003, in Denver, Colorado; Albuquerque, New Mexico; Houston, Texas; and Washington, DC. At those workshops, MMS asked for discussion regarding, among other things, the best published index to use in valuing production not sold at arm's length and related timing issues, greater specificity regarding allowable transportation costs, the rate of return on undepreciated capital investment in calculating actual transportation costs, and the royalty effect of sales under joint operating agreements. After considering the input from these workshops, MMS is proposing these amendments in an effort to improve the current rule.

The amendments proposed do not alter the basic structure or underlying principles of the June 2000 rule. In proposing these amendments, the Department of the Interior reaffirms that the value for royalty purposes of crude oil produced from Federal leases is value at or near the lease. But in determining value at the lease of production not sold under an arm's-length contract at the lease, MMS is not restricted to a comparison to arm's-length sales of other production occurring in the field or area. MMS may begin with a ''downstream'' price or value, and determine value at the lease by deducting the costs of transporting oil to downstream sales points or markets, or by making appropriate adjustments for location and quality.

Federal lessees are not obligated to sell crude oil downstream of the lease. Lessees are at liberty to sell production at or near the lease, even if selling downstream might have resulted in a higher royalty value for the production than selling it at the lease. If lessees do choose to sell downstream, the choice to sell downstream does not make otherwise non-deductible costs deductible (for example, marketing costs). *See Independent Petroleum Association of America, et al.* v. *DeWitt, 279 F.3d 1036 (D.C. Cir. 2002), cert. denied sub nom., Independent Petroleum Association of America, et al.* v. *Watson, __U.S.__, 123 S. Ct. 869 (Jan. 13, 2003).*

In the following discussion, we group the proposed changes by issue category and discuss the specific proposed changes to specific sections of the rule in that context.

A. Change to NYMEX-Based Valuation—§ 206.103

1. Determining the NYMEX Price To Use for Valuation

For crude oil not sold at arm's length, the existing rule at § 206.103 provides for the use of spot prices at defined market centers published in approved publications both of which are listed in **Federal Register** Notices available on the MMS Internet site at *http://www.mrm.mms.gov/Laws_R_D/FRNotices/,* as the basis for valuation of crude oil for most of the country except the Rocky Mountain Region. (In the Rocky Mountain Region, spot prices are the basis for the third ''benchmark.'') Our experience with the rule and comments we have received lead us to believe that, at this time, New York Mercantile Exchange (NYMEX) futures prices may represent a more reliable and better assessment of current oil values than spot prices.

Use of the NYMEX price as the basis for royalty value may have several advantages, not the least of which is the fact that the volume of transactions and the number of participants is so large that, at least theoretically, no one entity could manipulate the resultant price. This is an issue partly because of the recent publicity and questions about the information provided to spot price reporting services and the effect such potentially inaccurate information has on spot prices in general. In addition, there is only one NYMEX price, and it is available from any number of sources. There would be no question about the ''correct'' publication to use to obtain the applicable index price.

Further, various questions have arisen about the timing of application of index prices. Published spot prices for specific months generally represent the market's assessment of prices for crude oil delivered during that month, but determined between the 26th day of the month 2 months prior to the delivery month and the 25th day of the month immediately preceding the delivery month. This is not true for California, where all the days in the calendar month preceding the month of delivery are used to assess spot prices applicable to the month of delivery.

MMS has studied the correlation between several public indicia of crude oil prices (*e.g.*, trading month spot prices, NYMEX prices, etc.) and the values actually used in paying royalties to MMS on crude oil sold at arm's length. These studies demonstrate that calendar-month NYMEX prices (applying the ''roll'', (as discussed below, to Gulf of Mexico, mid-continent, and Permian Basin production) have the highest correlation to reported arm's-length sales values of any publicly-available indices. We have examined both onshore and Gulf of Mexico crude oil types, and this conclusion applies to both.

Under the proposed rule, the ''initial'' or ''base'' NYMEX price that would be used to value production in a given production month is calculated by averaging the daily NYMEX settlement prices for each trading day in that month for deliveries in the first future month (known as the ''prompt month''), excluding weekends and holidays. The prompt month changes during the production month so that in the beginning of the month the prompt month is the first month after the month of production. According to the NYMEX rules, trading ends at the close of business on the third business day prior to the 25th calendar day of the month (or the first business day prior to the 25th) preceding the delivery month. After that date the prompt month becomes the second month after the production month. *See* the NYMEX Web site for the specifications: *http://www.nymex.com/jsp/markets/lsco_fut_specif.jsp*.

We are proposing to exclude weekends and holidays for two reasons. First, if we include weekends and holidays, we would need to assign a price from other days on which trades actually take place. The normal way to do this is to use the preceding day's price (usually Friday's) on the assumption that that is the most accurate reflection of the price for deliveries that take place on the weekend. However, that results in weighting Fridays three times as much as other days. MMS does not believe there is a justification for overweighting Friday prices. The second reason that MMS is proposing to exclude weekends and holidays is that it is MMS's understanding that it is more common industry practice to exclude them in calculating monthly average prices on the NYMEX.

For example, to value production from Federal leases in March 2003 using NYMEX prices, you would average the NYMEX settlement prices published each business day in March, between March 1 and March 22, for April 2003, and between March 23 and 31 for May 2003. Importantly, this calculation is based on ''trading days during the calendar month.'' This is different from ''trading month,'' which is a term of art defined in these rules, as discussed below.

The 2000 rule uses prices assessed for the trading period that is as close to concurrent with the production month as possible. However, we've received comments that this period this is not consistent with the way industry does business. Under this proposal, the daily NYMEX prices used correspond more closely to the production month than under the existing rule.

MMS is proposing to apply a ''roll'' to the initial NYMEX oil prices from leases in the Gulf of Mexico and the mid-continent, including the Permian Basin. The ''roll'' is a commonly used measure of the trend of NYMEX prices for future deliveries in those areas. Proposing use of the roll necessitates proposing to change the definition of ''trading month.'' In section 206.101 of the current rule, ''trading month'' is defined in terms of spot market sales. Because the NYMEX price is the measure of value under the proposed rule, and because MMS proposes to use the roll, MMS proposes to change the definition of ''trading month'' to conform with NYMEX definitions and practice.

MMS proposes to define trading month to mean the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, *http://www.nymex.com,* in which case the NYMEX definition will apply.

Prices reported for futures contracts on the NYMEX are not limited to deliveries in the prompt month. Rather, trades could be made in March 2003 for deliveries in April 2003 or in several subsequent months. Due to the fact that the NYMEX prices are future price estimates, and therefore inherently reflect increases or decreases in prices based upon expected trends, an adjustment to such estimates is necessary in order to extrapolate back to current price estimates, upon which royalty calculations are based. This adjustment factor is the ''roll,'' which is added to the initial NYMEX price when the market is falling (to correct for the fact that the current price should be higher than the future price in a falling market) and subtracted from the initial NYMEX prices when the market is rising (to correct for the fact that the current price should be lower than the future price if the market is rising). We are proposing to use the roll because we believe it represents current market practice in establishing the sales price for crude oil production in certain regions of the country.

The roll formula includes the future prices for the two months beyond the prompt month, which is not the same as the prompt month used to determine the initial NYMEX price and assigns a progressively smaller weight to the second and third months. This is consistent with MMS's understanding of the common industry practice, including the weights and basis for the prices in the formula below. Specifically, the roll is calculated as follows:

$Roll = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2)$, where

- P_0=the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month.
- P_1=the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, as published for each day during the trading month for which the month of production is the prompt month.
- P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month.

Note that although prices P_0, P_1, and P_2 represent separate prices for periods 1, 2, and 3 months beyond the trading month, respectively, they are all determined during the same trading month. The roll may be a positive or a negative number, and, therefore, increase or decrease the royalty value, depending on whether the futures market is falling or rising.

For example, assume that the month of production for which you must determine royalty value is March 2003. March was the prompt month on the NYMEX (for year 2003) from January 22 through February 20, which is the trading month in this case. April is the first month following the month of production, and May is the second month following the month of production. As explained above, to determine the initial NYMEX price which the roll will adjust, for March 2003 production you first take the average of the daily settlement prices published for each business day from March 1 through March 20 for deliveries in April (the prompt month) and for each business day from March 21 through March 31 for deliveries in May (after May becomes the prompt month).

To calculate P_0, a different set of days is used. P_0 is the average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 22 and February 20 (the trading month). P_1 is the average of the daily NYMEX settlement prices for deliveries during April published for each business day during the same trading month (*i.e.*, between January 22 and February 20). Similarly, P_2 is the average of the daily NYMEX settlement prices for deliveries during May published for each business day during the same trading month used for P_0 and P_1. In this example, assume that P_0 = \$28.00 per bbl, P_1 = \$27.70 per bbl, and P_2 = \$27.10 per bbl. In this declining market, the roll = .6667 × (\$28.00 minus; 27.70) + .3333 × (\$28.00 − 27.10) = \$.20 + \$.30 = \$.50. Fifty cents per barrel would then be added to the initial NYMEX settlement price used as the basis for royalty valuation. We have developed an illustration of this example and others which are available on the MMS Web site at *http://www.mrm.mms.gov/OilVal/ValGuid.htm.*

In this example, since the market is falling, prices that traders anticipate during the trading month (March) for deliveries in a future prompt month are lower than the prices at which oil actually is selling during March. The roll accounts for that trend. The roll will have the opposite effect in a rising market. The roll will be a subtraction from the initial NYMEX price calculation (adding a negative number to the NYMEX price) because traders anticipate higher prices for the future prompt months than actually are occurring during the calendar month of production.

The roll would be added to the initial NYMEX price used as the basis for royalty valuation, except for leases in California, Alaska, and the Rocky Mountain Region. The reason for this limitation is that at the workshops, industry representatives stated that they use the roll primarily for Gulf of Mexico and mid-continent production, and not for production in California, Alaska, or the Rocky Mountain Region.

While MMS expects the basic operation of the NYMEX market to be the same for the foreseeable future, it is not so clear that the roll will be a permanent feature of the marketplace. Therefore, MMS proposes that the Director of MMS would have the option of terminating use of the roll when MMS believes that using the roll is no longer a common industry practice at the end of each two-year period following the effective date of this paragraph through notice published in the **Federal Register** no later than 60 days before the end of the two-year period. Further, MMS also proposes to have the option to redefine how the roll is calculated to comport with changes in industry practice through notice published in the **Federal Register** no later than 60 days before the end of the two-year period. MMS will explain its rationale when it publishes the notice. MMS believes that this flexibility is appropriate so that the valuation standards more closely reflect market developments. MMS specifically requests comments on whether this is appropriate, and whether a two-year period is appropriate.

MMS is proposing to use NYMEX-based value as the basic measure of value for production not sold at arm's length in all areas except for the Rocky Mountain Region, where MMS proposes to use it as the revised third benchmark (proposed to be redesignated as section 206.103(b)(3)). As discussed earlier, the roll would not be added to the NYMEX price in the Rocky Mountain Region since its use does not reflect current industry practice there. The base NYMEX price would be adjusted for location and quality differentials and actual transportation costs back to the lease, as explained below.

2. Adjusting the NYMEX Price for Transportation Costs and Location and Quality Differentials

Under the 2000 rule, market center index (spot) prices are adjusted to determine the value of production at the lease through location and quality differentials and deduction of actual transportation costs. *See* 30 CFR § 206.103 and 206.112. Location and quality differentials are derived from lessees' own arm's-length exchange agreements or, if exchanges are not at arm's-length, through MMS approval. Actual transportation costs from the lease to a market center or intermediate exchange point are determined under 30 CFR § 206.110 and 206.111 according to whether transportation arrangements are arm's-length or non-arm's-length.

Adopting the NYMEX price as the basis for royalty valuation requires an additional adjustment beyond those in the current rule because the NYMEX price is defined only at Cushing, Oklahoma for light sweet crude oil. Therefore, differentials from Cushing to market centers other than Cushing are necessary. MMS believes that many lessees do not have arm's-length exchange agreements between each market center to which they transport or trade and Cushing. Therefore, MMS proposes to allow the use of published differentials when lessees do not exchange oil to Cushing at arm's length. Accordingly, MMS proposes to define a new term, ''WTI differential,'' as follows:

> WTI differential means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma, published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

Example. Assume the production month is March 2003. Industry trade publications perform their price surveys and determine differentials during January 26 through February 25 for oil delivered in March. (California is an exception. In California, the survey covers the calendar month of February for March deliveries.) The WTI differential (for example, the West Texas Sour crude at Midland, Texas, spread versus WTI) applicable to valuing oil produced in the March 2003 production month would be determined using all the business days for which differentials are published during the period January 26 through February 25. Note, in this example, that the days used in the monthly average calculation of the WTI differential are different than the days used to calculate the NYMEX price and are different than the days used to calculate the roll.

This definition is intended to allow the lessee a method of calculating an accurate price at a market center near the lease so that crude oil produced from the lease can be accurately valued. The price at each market center would be the average of the daily NYMEX settlement prices published during the calendar month of production (including the roll, if applicable) plus or minus the appropriate WTI published differential. The lessee would then calculate a further differential from the market center to the lease.

For example, if a producer does not have an arm's-length exchange agreement to Cushing, and the applicable NYMEX price (including the roll) is $29.00/bbl, and the WTI differential for Light Louisiana Sweet (LLS) crude oil is plus $.30/bbl at St. James, Louisiana, the value at St. James would be $29.30. That value must be further adjusted from the market center to the lease by applicable location and quality differentials and for actual transportation costs between the lease and the market center.

Continuing the example, if a lessee produced Eugene Island (EI) sour crude and transported it from the lease to Burns Terminal at a cost of $1.19 per barrel, where it exchanged it at arm's length for LLS at St. James on the basis of $27.50/bbl for the EI crude and $28.80/bbl for the LLS, the value of the EI crude would be $29.30 (the LLS value at St. James) less the location and quality differential from the exchange agreement ($1.30), or $28.00. The lessee could then take the transportation allowance of $1.19 to get a value of $26.81 at the lease.

Changing from spot market index price-based valuation to NYMEX-based valuation and adding a definition for ''WTI differential'' would require a revision in the definition of ''MMS-approved publication.'' In the context of the proposed valuation scheme, and because NYMEX prices are widely available, the only context in which MMS approval of a publication would be needed is for determining the WTI differential. Accordingly, the proposed rule would revise the definition of ''MMS-approved publication'' to read:

MMS-approved publication means a publication MMS approves for determining WTI differentials.

3. Specific Comments Requested

MMS requests specific comments about changing the valuation basis for transactions not at arm's length from spot to NYMEX prices, and to a calendar month average of such prices. MMS also requests specific comments on whether weekends and holidays should be included in the calculation of the average NYMEX price (and, if so, what price should be assigned to days on which no price is published). Further, MMS requests comments on whether it should include the ''roll'' in the calculation of the proper NYMEX price and whether the roll should apply only to areas other than California, Alaska, and the Rocky Mountain Region. MMS also requests comments on (1) whether lessees should use the location and quality differentials in their own arm's-length exchange agreements between Cushing and the lease or market center in preference to WTI differentials and (2) the circumstances under which they should use one or the other.

Under proposed section 206.103(a), for leases in California and Alaska, you must adjust the NYMEX price for applicable location and quality differentials and you may adjust for actual transportation costs, as described at section 206.112. MMS also requests comments on whether it should retain ANS spot prices as the valuation basis for crude oil produced in California and Alaska instead of changing the valuation basis to the NYMEX price.

B. Determining Differentials When Using NYMEX-Based Valuation When Lessees Do Not Have Information From Their Own Exchange Agreements—§§ 206.103 and 206.104

Based on requests we have received for valuation guidance and future valuation agreements for the Rocky Mountain Region, as well as our experience with RIK in that area, we believe that very few producers in the Rocky Mountain Region have actual trades of crude to Cushing. The same situation may apply to production in other areas, especially California. Therefore, in many cases producers do not have access to information to make adjustments to a price at Cushing. MMS therefore is proposing a change in how location and quality adjustments are made when you don't have an actual location and quality differential between Cushing and either the lease or a location to which you actually transport or exchange the oil.

For example, in the Rocky Mountain Region for sweet crude oil produced from leases in Wyoming, the market center would be Guernsey, Wyoming. Under the proposed rule, you would use the WTI differential for Wyoming Sweet at Guernsey for sweet crude oil, as published in an MMS-approved publication. If you use the WTI differential for Wyoming Sweet at Guernsey, and you transport your oil to Guernsey, you may also subtract actual transportation costs from the lease to Guernsey. If you exchange your oil from the lease to Guernsey, you must apply the appropriate location and quality differential to Guernsey. In the case of much of the crude oil produced from Federal leases in California, MMS anticipates that the market center would be Line 63 (for crude oil of like-quality to the crude oil for which Line 63 spot prices are published) or Kern River (for crude oil of like-quality to the crude oil for which Kern River spot prices are published).

More specifically, if the NYMEX price (unadjusted by the roll) is $29.00 and you do not have an arm's-length exchange agreement between Cushing and anywhere in Wyoming from which you could calculate a location and quality differential for your sweet crude, you would use the Guernsey WTI differential to value your sweet crude oil if you transport or exchange some or all of your oil to Guernsey. If the Guernsey WTI differential, calculated by taking the average of the daily high and lows and then averaged over the published days of the month, was −$.50/bbl, the value at Guernsey would be $29.00 − $.50 = $28.50/bbl. From this value, you could then subtract your transportation costs (or you would adjust for location and quality) from the lease to Guernsey.

If you did not move or exchange any of your oil to Guernsey, you would have to propose an alternative location and quality differential (between the lease and Guernsey) to MMS. You would then apply the WTI differential at Guernsey to adjust to Cushing. MMS is proposing that you may use the differential from the lease to Guernsey that you propose until MMS prescribes a different differential. If MMS prescribes a different differential, you would have to apply MMS' differential to all periods for which you used your proposed differential. You would have to pay any additional royalties resulting from using MMS' differential, plus late payment interest from the original royalty due date, or you would report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

MMS also requests comments regarding alternative valuation procedures, including differentials, in valuing sour crude oil in light of the fact that the WTI price at Cushing is for light sweet crude oil. For example, would it be useful to begin valuation of sour crude produced in the Rocky Mountain Region at Hardisty, Alberta, Canada (at which spot market prices for sour crude are published in trade publications), and adjust the Hardisty price for the cost of transportation from Casper, Wyoming (a typical delivery point) to Hardisty and from the lease to Casper? Because Hardisty is farther from Rocky Mountain market and refineries, MMS proposed that applicable transportation costs would be added to, rather than subtracted from, this market center's prices. MMS would like to better understand the number of companies for whom Hardisty would be an appropriate market center. Would it be better in such cases for the lessee to consult directly with MMS on the proper valuation procedure rather than MMS providing specifics in the rule?

C. What Adjustments and Transportation Allowances Apply When Valuing Production Using Index Pricing?—§ 206.112

MMS is proposing to revise the framework of how and when to apply location and quality differentials and transportation allowances in calculating royalty value. The current rules are based on the proposition that the value of oil not sold at arm's length can be accurately measured by known, accepted index prices at market centers. In order to accommodate certain transactions where the oil does not flow to a market center, the current rule allows lessees, in certain circumstances, to value the oil as if its value were the same at some alternative location (such as a refinery) as it would be at a market center. For example, the regulation currently provides that ''if you transport lease production directly to * * * an alternate disposal point, you may adjust the index price for your actual transportation costs.'' 30 CFR § 206.112(c). However, value at a refinery may not be the same as the value at a market center.

To be sure that all royalty values are properly adjusted by market-based location and quality differentials (and transportation costs) to the NYMEX pricing point (Cushing), MMS is proposing to rewrite section 206.112. Proposed section 206.112 would clarify that if royalty value at the lease is calculated by starting with the NYMEX price, the NYMEX price would then be adjusted by applicable transportation costs or location and quality differentials between the lease and the market center, and then between the market center and Cushing.

Paragraph (a) of proposed section 206.112 would apply to that portion of the oil produced from your lease that is transported or exchanged (or both transported and exchanged) between the lease and the market center. Paragraphs (b) and (c) would apply to the remainder of your oil. Under paragraph (a), if you transport your oil over any segment (*i.e.*, between any two points) between the lease and the market center, you would determine a transportation allowance under either section 206.110 or 206.111. If you exchange your oil for any segment between the lease and the market center, you would use location and quality differentials derived from your arm's-length exchange agreements. (If an exchange agreement is not at arm's-length, you would have to obtain MMS approval for a location and quality adjustment. Until MMS approves a proposed location and quality differential, you would use the location and quality differential derived from your non-arm's-length exchange agreement. If MMS prescribes a different differential, you would have to adjust previously reported and paid royalties, together with appropriate interest payments or credits. If you do not have an arm's-length exchange agreement for your oil between the market center and Cushing, you would use the WTI differential to adjust for location and quality between the market center and Cushing. You could not both take a transportation allowance and apply a location and quality differential between the same two points.

For example, a lessee produces sour crude from a lease in the Gulf of Mexico that trades as Eugene Island (EI) crude. Assume that the lessee transports 35 percent of the oil produced from the lease to the market center at Houma, Louisiana. To determine the value of that 35 percent of the production, the lessee first would determine its transportation allowance from the lease to Houma under section 206.110 or 206.111, as applicable. In the alternative, if the lessee has an arm's-length exchange agreement between the lease and Houma, it would use the location and quality differential derived from that exchange agreement for the change in location covered by the exchange agreement. The lessee would adjust the NYMEX price by the transportation costs or the location and quality differential. If the lessee exchanges the oil under an arm's-length exchange agreement between Houma and Cushing, it would further adjust the NYMEX price by the location and quality differential derived from that agreement. Alternatively, if the lessee did not exchange the oil between Houma and Cushing at arm's length, the lessee would adjust the NYMEX price by the published WTI-EI differential.

Paragraph (a) also addresses the situation in which the lessee both transports *and* exchanges a particular volume of oil from the lease to a market center. Therefore, assume the lessee transports 35 percent of the oil produced from the lease to Caillou Island and then exchanges that oil with another party at arm's length for Light Louisiana Sweet (LLS) at St. James, Louisiana, which is the LLS market center. To get the royalty value at Caillou Island, the lessee must add the differential in the exchange agreement (assume − $1.00) to the market value of LLS, which is the NYMEX price plus the WTI–LLS differential (assume − $.50). Assuming a NYMEX price of $29.00, the value at Caillou Island would be $27.50. The lessee may then subtract its transportation costs from the lease to Caillou Island (assume $1.00) to determine the royalty value at the lease (a net value of $26.50).

In the case of much of the crude oil produced from Federal leases in California, MMS anticipates that the market center would be Line 63 (for crude oil of like-quality to the crude oil for which Line 63 spot prices are published) or Kern River (for crude oil of like-quality to the crude oil for which Kern River spot prices are published). Therefore, to determine the adjusted NYMEX price for oil transported or exchanged to either of these market centers, the lessee would adjust the NYMEX price for the WTI differential between Cushing and the applicable market center.

Paragraph (b) or (c) of proposed section 206.112 applies when some, but not all of a lessee's oil is exchanged or transported to or through a market center. Paragraph (b) applies if the lessee transports or exchanges (or both transports and exchanges) at least 20 percent of the oil produced from the lease to a market center. In that event, the lessee would value that portion of the oil not transported or exchanged to a market center by the volume-weighted average of the values of the oil valued under paragraph (a). Therefore, in the preceding example, the lessee transported and exchanged 35 percent of its oil from the lease to the market center at St. James. The value of that oil calculated in that example was $26.50/bbl. Assume that the lessee also transported another 45 percent of its oil from the lease to St. James, and that the adjusted NYMEX-based value of that oil was $27.00/bbl. Finally, assume that the lessee transported the remaining 20 percent of the oil to its refinery in New Jersey. Under the current regulation, the lessee must come to MMS for advice as to how to value the portion of the oil transported to New Jersey. Under the proposed rule, to determine the value of that 20 percent, the lessee would calculate the volume-weighted average of the other two dispositions. In this example, the volume-weighted average = $((.35 \times 26.50) + (.45 \times 27.00))/.8$ = \$26.78. The value of the 20 percent transported to the lessee's refinery would be \$26.78.

MMS seeks comments on this proposal as well as comments on whether 20 percent is a sufficient volume on which to base the value of oil that the lessee could not otherwise value under the current rule. MMS selected the 20 percent figure for this proposal because it is greater than the royalty percentage under the typical offshore lease (16⅔ percent).

Paragraph (c) of proposed section 206.112 addresses the situation where the lessee does not transport or exchange at least 20 percent of the oil to a market center. The lessee would use paragraph (a) to value the less than 20 percent portion (if any) that the lessee transports or exchanges (or both transports and exchanges) to a market center. For the remainder of its lease production, the lessee must come to MMS with a proposal for a location and quality differential between the lease and the market center. If MMS approves a different differential, the lessee would have to adjust its previously reported and paid royalties, together with an interest payment or credit. The lessee would use the WTI differential to adjust between the market center and Cushing.

Finally, the current rule is not clear about all situations in which a quality differential would be appropriate. For example, a lessee could transport its oil from the lease to its refinery at a market center, but its oil may be of a higher gravity and a lower sulfur content than the crude for which a price is published at the market center. In this situation, the lessee should make an adjustment for quality even though it has no exchange agreement or quality bank to use to make the adjustment. MMS proposes that in such circumstances, a lessee would use appropriate posted price gravity tables to adjust the value of its produced crude for gravity differences from the market center benchmark crude, and use a factor of 2.5 cents per one-tenth percent difference in sulfur content to adjust for quality when it has neither exchange agreements nor quality banks to fully adjust the quality of its oil to that of the crude oil at the market center. MMS has based this factor on its understanding of common sulfur bank adjustments for California. For instance, MMS understands, from its RIK program, that the All America Pipeline uses a sulfur adjustment of 50 cents per percent, after the first percent difference in sulfur. MMS believes that the typical sulfur content of oil produced from Federal leases is in the one to three percent range. Therefore, MMS' use of 2.5 cents per 0.1 percent sulfur difference would be similar to the factor used by the All America Pipeline. MMS believes that the ability to use a sulfur quality adjustment is a concern in California, but is seeking comments on whether producers in other parts of the country would find it useful as well. MMS also seeks comments on whether these are reasonable differentials, both for California and the rest of the country.

D. Transportation Cost Issues—§§ 206.110 and 206.111

1. Proposed Change to Rate of Return on Undepreciated Capital Investment — § 206.111(i)(2)

MMS is proposing to amend the regulations governing calculation of actual transportation costs in non-arm's-length situations by changing the allowed rate of return on undepreciated capital investment. In 1988, MMS determined that the appropriate rate of return was equal to the Standard and Poor's BBB bond rate. MMS explained its choice as follows:

> The MMS has examined several options relating to rate of return and decided that a rate of return should be closely associated with the cost of money necessary to construct transportation facilities. The MMS has examined the use of the corporate bond rate very carefully and has concluded that such rates are representative of the loan rates on sums of money comparable to that expected for the construction of transportation facilities.
>
> There is no doubt that there are some very high risks involved with some oil and gas ventures, such as wildcat drilling. However, the risk associated with building and developing a pipeline to move oil that has already been discovered is a much different risk. The risk of default (financial risk) is considered in corporate bond rates. Considering the risks related to transportation systems, a rate of return based on an applicable corporate bond rate would be appropriate for transportation systems.

53 FR 1213 (1988)

In 2000, when MMS revised the oil valuation regulations, MMS explained why it would continue to use the Standard and Poor's BBB bond rate as the rate of return for transportation allowances:

> 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. * * * 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 * * *
>
> The industry proposes using a weighted average cost of capital. * * * [W]e 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 before-tax rate as well. * * * 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. * * * [S]ince 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.

65 FR 14051

MMS believes that a market-based cost of capital is needed to reflect accurately the actual and necessary costs to owners of transportation systems. The capital costs, in addition to operating and maintenance expenses, must be accounted for in calculating costs. Capital costs are normally accounted for by allowing depreciation plus a rate of return on undepreciated capital investment.

Industry has challenged the 2000 rule as allegedly arbitrary and capricious in the lawsuit cited earlier. Among the challenged aspects of that rule is whether the Standard and Poor's BBB corporate bond rate is sufficient as an average rate of return on transportation capital investments. The 2000 rule also eliminated the exception allowing lessees to use tariffs filed with FERC as a transportation allowance in lieu of calculating actual transportation costs. Consequently, after June 1, 2000, calculation of actual costs, and the use of the rate of return as part of the calculation, was required of all lessees who did not have arm's-length transportation arrangements. The judicial challenge to the 2000 rule has led MMS to reconsider whether BBB is a sufficient rate of return.

When MMS promulgated regulations to value geothermal resources in 1992, MMS believed that the return on capital needed to compute properly a deduction for the costs of generating electricity should be the weighted average of the returns to equity and debt (without considering income tax treatment). That led MMS to determine that two times the BBB rate was appropriate for that calculation.

MMS has examined some rates of return in the oil industry and believes that some weighted average rate of return considering both equity and debt is appropriate as an actual market-based cost of capital. MMS believes that establishing a uniform rate of return on which all parties can rely is preferable to the costs, delays, and uncertainty inherent in attempting to analyze appropriate project-specific or company-specific rates of return on investment.

MMS believes that the subset of companies that have invested, or are likely to invest, in oil pipelines is a very limited subset of the oil industry. MMS also believes that no standard industrial classification corresponds to those who are willing to invest in pipelines. MMS has received a new study from the American Petroleum Institute (''API''), titled ''BBB Bond Rate Not an Adequate Measure of Capital Cost,'' that concluded that the cost of capital (after taxes) of the Department of Energy's Financial Reporting Service Companies was closer to 1.6 to 1.8 times the Standard and Poor's BBB bond rate. The API study explained that this group of producers included the companies that would be most likely to own pipelines. MMS, through its Offshore Minerals Management, Economics Division, has also studied several years' worth of data for both non-integrated oil transportation companies and larger oil producers, both integrated and independent, that MMS believes are more likely to invest in oil pipelines. This study concluded that that range of rates of return that would be appropriate for oil pipelines would be in the range of 1.1 to 1.5 times the Standard and Poor's BBB bond rate. While the relationship between the rates of return that MMS has examined and the BBB rate has not been constant, MMS is proposing for comment a rate of return of 1.5 times the Standard and Poor's BBB rate as this rate is within the range recommended by its own experts and close to the rate recommended by the industry experts.

2. Specification of Certain Allowable and Non-Allowable Costs—§§ 206.110 and 206.111

(i) Arm's-Length Transportation

In Section 206.110, MMS is proposing to add a new paragraph (b) that would specify many of the costs incurred for transporting oil under an arm's-length contract that are allowable deductions. MMS believes these costs are costs that are directly related to the movement of crude oil to markets away from the lease. Those costs include:

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid to a pipeline owner for administration of a quality bank.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(i) Multiply the volume that the pipeline requires the shipper to maintain in the pipeline by the value of that volume for the current month calculated under section 206.102 or section 206.103, as applicable; and (ii) multiply the value calculated under paragraph (i) by the monthly rate of return, calculated by dividing the rate of return specified in section 206.111(i)(2) by 12.

MMS proposes to allow this deduction because this cost appears to be an actual cost directly associated with transporting oil. In each month for which line fill is required, a shipper incurs the loss of available capital associated with the value of the line fill volume. The proposal therefore would allow a return on that value, calculated as described above. MMS seeks comments on whether this cost should be allowed as part of the transportation deduction.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

MMS proposes to allow lessees to deduct transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when the shipper does not sell the oil at the hub. MMS believes that this also is a cost directly incurred for movement of the oil. MMS believes that title transfer fees are a cost of selling oil, not moving it, and are not deductible.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation. While this situation does not arise frequently, MMS believes that in such cases, this volumetric deduction is an actual cost incurred in moving oil.

(10) Costs of securing a letter of credit or other surety that the pipeline requires a shipper to maintain. These costs should only include the currently allocable costs applicable to the Federal lease. MMS believes that shippers can generally use two different means of assuring creditworthiness. The first involves a deposit or advanced payment in which the shipper incurs only the costs associated with the time value of money because they receive their deposit back. The other involves actual out-of-pocket costs to obtain a letter of credit, guarantee, or surety bond. MMS believes that these two means should be accounted for differently in calculating your transportation allowance.

In the first case, if you make a cash deposit of two months of the expected transportation charges (say $50,000), and transport 100,000 barrels per month, of which 75,000 barrels are from a Federal lease, you must calculate the cost as follows:

(i) Multiply the deposit by the monthly rate of return, calculated by dividing the rate of return specified in section 206.111(i)(2) by 12, and (ii) multiply that result by the proportion of total production from each Federal lease. In this example, if the Standard and Poor's BBB bond rate was 8%, the allowable monthly rate would be

$$\left(\frac{.08*1.5}{12}=.01\right),$$

and that would be multiplied by the amount of the deposit to get the monthly cost, which would be $500. Then you could include the share of that applicable to the Federal lease (75,000/100,000) = ¾. So you could include $375 as an allowable transportation cost for as long as the $50,000 is on deposit (and the other factors remain unchanged).

In the second case involving the expense of a letter of credit or other surety, if you pay your bank $5000 as a non-refundable fee for a letter of credit, you can include the proportion allocable to Federal production in the month that fee is paid, and then never again.

MMS believes that this is a cost that the lessee must incur to obtain the pipeline's transportation service, and therefore is a cost of moving the oil. MMS welcomes comments on whether these are reasonable ways to calculate the actual costs of assuring a lessee's creditworthiness.

You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this paragraph. MMS seeks comments regarding whether these various costs should be allowed, and whether there are other costs directly attributable to the transportation of crude oil that should be included in the final rule.

In section 206.110, MMS proposes a new paragraph (c) that would specify certain costs as not deductible. Those include:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to scheduling service providers.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

At the workshops, MMS received some comments that internal costs should be deductible. One person suggested that if an employee's only function were to arrange for downstream transportation of production, that person's salary should be deductible. MMS does not agree. Under the proposed rule, these types of indirect, internal costs are not deductible.

MMS does not believe that any of the above-described costs are incurred directly as part of the process of physically moving the crude oil. MMS seeks comments on whether any of these costs should be deductible.

(ii) Non-Arm's-Length Transportation

In section 206.111, MMS proposes to add a new paragraph (b)(6) that would specify many of the costs incurred for transporting oil under a non-arm's-length contract that are allowable deductions, but only to the extent they have not already been included in the actual cost calculation under paragraphs (d) through (j) of this section. Many of these costs are the same as those associated with arm's-length transportation contracts. Those costs include:

(1) Volumetric adjustments for actual line losses.

(2) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(A) Multiply the volume that the pipeline requires the shipper to maintain, and that it does maintain, in the pipeline by the value of that volume for the current month calculated under section 206.102 or section 206.103, as applicable; and (B) multiply the value calculated under paragraph (i) by the monthly rate of return, calculated by dividing the rate of return specified in section 206.111(i)(2) by 12.

(3) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(4) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(5) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

These costs parallel those costs itemized in the arm's-length transportation provisions in section 206.110(b) insofar as appropriate for non-arm's-length situations. Several of the specific items allowed under the arm's-length provisions do not occur or are not appropriate for inclusion in a non-arm's-length transportation situation. Specifically, in a non-arm's-length situation, there is no arm's-length transportation tariff. (Instead, the lessee must calculate its actual costs of building and operating the pipeline.) In addition, MMS believes that even if an affiliated pipeline charges quality bank administrative fees to its own affiliate, the lessee/shipper is simply paying its affiliate and that it should not be regarded as part of the actual costs incurred to move oil. Further, in a non-arm's-length situation, decisions regarding short-term storage (and the cost associated with that storage) are under the lessee's or its affiliate's control, and likely may be avoided. MMS therefore believes that it is not appropriate to allow a short-term storage cost. Also, in a non-arm's-length situation, any fees charged by an affiliated pipeline to pump oil over to a third party-carrier's system are paid within the same corporate organization and are not an additional actual cost of transportation. Finally, in non-arm's-length situations, MMS expects that requiring a letter of credit from an affiliated producer is unnecessary and that the corporate organization ordinarily would avoid incurring the costs of the premium necessary for the letter of credit. MMS therefore believes it inappropriate to allow such a deduction.

In contrast to the 2000 rule, which disallows all line losses in non-arm's-length transportation situations, MMS proposes to allow actual, but not theoretical, line losses. MMS believes that actual line losses properly may be regarded as a cost of moving oil. In addition, if there is a line gain, the lessee must reduce its transportation allowance accordingly. In a non-arm's-length situation, however, a charge for theoretical line losses would be artificial and would not be an actual cost to the lessee. While a lessee may have to pay an amount to a pipeline operator for theoretical line losses as part of an arm's-length tariff, in a non-arm's-length situation, line losses, like other costs, should be limited to actual costs incurred.

The MMS also is proposing to add a new paragraph (b)(7) to section 206.111 that would list the costs that expressly are not deductible as transportation costs. These are the same costs discussed above in the section on arm's-length transportation contracts (section 206.110), with one addition, namely, that theoretical line losses are not deductible under non-arm's-length transportation arrangements.

3. Technical Correction to § 206.111(h)(5) Regarding Redepreciation

We propose to modify existing § 206.111(h)(5) to remedy an unintended consequence regarding depreciation when calculating a transportation allowance not involving an arm's-length transportation contract. When we amended the rules in March 2000, we intended the revisions regarding depreciation in the current rule to permit, one time only, a new depreciation schedule based on your purchase price when you purchase a transportation system from a previous owner. If a transportation system were sold more than once, subsequent purchasers would have to maintain the then-existing depreciation schedule.

However, existing paragraph (h)(5) says "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.'' But if A were the original owner and still owned the system on June 1, 2000, and subsequently sold the system to B after June 1, 2000, who in turn sold it to C, the rule as written says that C would have to assume original owner A's depreciation schedule. This was not MMS' intent. To be consistent with the intended result, C should assume B's depreciation schedule in this situation.

Therefore, to reflect the original intent, MMS proposes to modify § 206.111(h)(5) to delete the words ''who owned the system on June 1, 2000'' and replace them with the words ''from whom you bought the system.'' This change would enable C in the example above to assume the depreciation schedule of B based on B's purchase price of the transportation system and subsequent reinvestment.

E. Treatment of Joint Operating Agreements—§ 206.102

In the preamble to the 2000 rule, MMS explained:

> 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.

65 FR 14060

Based upon further consideration of these situations, MMS does not believe there should be a presumption that all of these sorts of transactions are non-arm's-length and are not sales. When a party to a joint operating agreement, who is not the operator, allows the operator to dispose of its share of oil production in exchange for the consideration provided under that agreement, MMS recognizes that some of these arrangements may be sales of the production. The royalty value of the oil so transferred depends on whether the sale is an arm's-length sale. MMS expects that in most of the situations where the lessee is not the operator, the transaction may be at arm's-length. If the sale is at arm's-length, the question then becomes (as in any arm's-length situation) whether any of the exceptions in section 206.102(c) apply. In some circumstances, the sale also may be a marketing agreement, and the operator may be performing the marketing function for the lessee. In such a case, the MMS may determine that the lessee has improperly deducted marketing costs, and MMS may increase the royalty value accordingly. MMS will examine each case on its facts just as it does any other disposition of production.

MMS also proposes to change the reporting instructions in 30 CFR 210.53 with respect to sales under joint operating agreements to facilitate review and audit of these transactions. MMS proposes to add a new paragraph (c) to section 210.53 that would require an operator under a joint operating agreement who is also a designee and who reports and pays royalty on behalf of one or more working interest owners from whom the operator buys production, to report the share of the production it purchased from the working interest owners and the associated royalty payment on a separate line on the Form MMS–2014 from the line on which the operator reports its own share of production and the associated royalty payment.

F. Limit on Grace Period for Reporting Changes—§ 206.121

The MMS is proposing a technical correction to the regulation at section 206.121 that permitted a grace period for reporting and paying royalties after the June 2000 rule became effective to give royalty payors adequate time to change their systems. We are proposing to end-date the grace period for such adjustments, because we consider three years to be sufficient time to have reported and paid royalties under the regulations published in 2000.

G. Other Technical Changes

Section 206.103(b) applies to production from leases in the Rocky Mountain Region, a defined term. The current rule prescribes a series of four benchmarks described in paragraphs (b)(2) through (b)(5) for valuing production in the Rocky Mountain Region that is not sold at arm's-length. To provide clarity in this section of the rule, MMS is proposing to renumber paragraphs (b)(2) through (b)(5) to make them (b)(1) through (b)(4) so that the four benchmarks correspond with the four paragraph numbers. Other than this renumbering, the only change MMS is proposing to make to the valuation criteria for the Rocky Mountain Region is the change to the third benchmark from spot prices to NYMEX valuation, described above in I. A.

In addition, MMS proposes a technical change to the definition of ''affiliate'' in section 206.101. MMS would change paragraph (2) of the definition of ''affiliate'' by striking the words ''of between 10 and 50 percent'' and substituting therefor the words ''10 through 50 percent'' because the current definition does not specify the treatment of a situation in which one person owns exactly 50 percent of another.

H. Other Possible Changes That May Be Considered

In addition to issues already identified above on which MMS seeks comments, MMS specifically requests comments on the following issue: Should MMS allow using the NYMEX price to value oil sold at arm's-length in multiple sales downstream of the lease where the lessee does not first transfer to an affiliate and where ''tracing'' the production from the lease or unit to the specific sale is burdensome?

Under the 2000 rule, most lessees who are relatively large producers have the option of using a spot market index-based value even when the oil is sold at arm's length, because the lessee is working through an affiliate who is the seller in an arm's-length resale. Thus, if a lessee wants to avoid the burden of ''tracing'' the production to each particular sale out of a large number of sales to different purchasers, it may opt to use index-based value under the current 30 CFR § 206.102(d)(2). Lessees who do not first transfer to an affiliate and who sell directly to a large number of different purchasers do not have this option. MMS seeks comment on whether the option of using NYMEX prices should be extended to these situations in the event that MMS adopts NYMEX-based valuation.

II. Procedural Matters

1. Public Comment Policy

Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours and on our Internet site at *www.mrm.mms.gov*. Individual respondents may request that we withhold their home address from the rulemaking record, which we will honor to the extent allowable by law. There also may be circumstances in which we would withhold from the rulemaking record a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comments. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

2. Summary Cost and Royalty Impact Data

Summarized below are the estimated costs and royalty impacts of the proposed rule to all potentially affected groups: Industry, the Federal Government, and State and local governments. The costs and the royalty collection impacts, are segregated into two categories—those that would accrue in the first year after the proposed rule becomes effective and those that would accrue on a continuing basis each year thereafter.

A. Industry

(1) Expected Increase in Royalties—NYMEX-Based Valuation Applied to Oil Not Sold at Arm's Length

Under this proposed rule, industry would value oil based on a market price that more closely represents the true value of the oil. We believe this may result in industry paying additional royalties compared to the current regulations. We provide estimates below of any significant increased royalties under the proposed rule.

The proposed rule maintains many of the provisions of the Federal oil valuation rule that became effective June 1, 2000 (the June 2000 Rule), including the concept of three separate valuation methodologies linked to different production locations. This analysis also is divided into the same three areas. They include California/Alaska (onshore and offshore), the Rocky Mountain Region, and the ''rest of the country'' including the Gulf of Mexico. This analysis highlights the impacts of modifying the pricing provisions and methodologies. The allowed adjustments for transportation and quality as outlined in the June 2000 Rule also would change somewhat, and some additional corresponding analysis is necessary.

''Rest of the Country''

In valuing production not sold under an arm's-length contract, the June 2000 Rule employed the spot price of the oil most closely associated with the production, with appropriate adjustments for location and quality. The timing of the spot month that corresponds with the production month is the quoted average from an MMS-approved publication from the 26th day of the month prior to the current production month to the 25th day of the current production month. For example, December royalty production is valued using the spot quotes for the oil most similar in location and quality from November 26th through December 25th.

The proposed new methodology for the ''rest of the country,'' as discussed earlier, is the NYMEX Calendar Month Average daily settlement price with the ''roll'' and a differential. This method uses a trading month differential (found in MMS-approved publications and based on spot price quotes) applied to the average of the daily NYMEX prices, excluding weekends and holidays, during the production month for deliveries during the prompt month as defined in the proposed rule. For example, for the month of December, assume a producer seeks to value production whose characteristics are closely related to Light Louisiana Sweet (LLS) crude oil. The grade differential established over the period October 26 through November 25 would be applied to the average of the daily NYMEX prompt month prices published for each day in the month of December. The grade differential is the WTI spot price for the period October 26–November 25 less the LLS spot price for the same period. Assuming the WTI value is $29.00 per barrel and the LLS value is $28.00 per barrel, the differential is $1.00 per barrel.

The forward ''roll'' is added to the calendar month average NYMEX value and is determined by taking a ratio of the difference between the current month value, the 2nd month out future value, and the 3rd month out future value as reported on the NYMEX exchange. Assuming the ''roll'' calculation results in a value of $0.30 per barrel, the calculated royalty value, assuming the NYMEX calendar month average price is $29.50 per barrel, is $28.80 per barrel (including both the roll and the differential). It is calculated as follows for all royalty production not disposed of at arm's length in the month of December:

(NYMEX Calendar Month Average + ''roll'') − (Spot average WTI − Spot Average LLS) ($29.50 + $.30) − ($29 − $28) = $28.80 per barrel for December royalty production valued as not sold under an arm's-length contract.

We have compared prices under NYMEX adjusted for the roll and the grade differential discussed above with prices calculated under the existing rule based on spot prices at each of the market centers applicable in the ''rest of the country—*e.g.*, Midland, St. James, and Empire. We found that over the period April 2000 through December 2002, or the period from approximately when the current rule became effective through the end of calendar year 2002, the adjusted average monthly NYMEX price exceeded the monthly average spot prices for these market centers by about $0.31 per barrel. We also have performed this comparison back to the beginning of 1999 and found that the difference is slightly higher over the entire period January 1999 through December 2002. We chose the $0.31 per barrel increment as the basis for our royalty impact estimates.

In estimating the impact of a change to NYMEX valuation, we made several assumptions in addition to the $0.31 per barrel increment. We assumed that 50 percent of all Federal barrels would be valued under the non-arm's-length provisions, that the offshore royalty rate is one-sixth and onshore royalty rate is one-eighth, and that volumes taken in kind would vary from 50,000 barrels per day to 180,000 barrels per day. The former includes only barrels currently taken in the small refiner program, and the latter includes small refiner volumes plus barrels currently going to the Strategic Petroleum Reserve. We then subtracted the volumes taken in kind and applied the $0.31 per barrel figure to the remaining barrels assumed to be valued under the non-arm's-length provisions. We estimate increased costs to industry in the form of higher royalty payments of $4,303,913 to $11,658,663 million per year.

California/Alaska

The current rule specifies Alaska North Slope (ANS) spot prices for oil delivered at Long Beach, California as the valuation basis for all crude produced in California or Alaska and not sold at arm's length. The ANS spot quotes on a monthly average basis (without weekends or holidays) apply directly to the production month. That is, the spot quotes from December 1st through the 31st apply directly to December production. The rule allows for transportation adjustments and quality allowances.

The proposed new methodology is the NYMEX Calendar Month Average daily settlement price with appropriate differentials, but without the ''roll'' discussed above. This method uses a trade-month differential (found in MMS-approved publications and based on spot price quotes) applied to the average of the daily NYMEX prices, excluding weekends and holidays, published for each day during the production month for deliveries during the prompt month as defined in the proposed rule.

For example, for the month of December, assume a producer seeks to value production whose quality and location are similar to Kern River crude oil (13.4 degree API gravity oil in Kern County). The grade differential established over the period October 26 through November 25 would be applied to the average of the daily NYMEX prompt month prices published for each day in the month of December. The grade differential is the WTI spot price for the period October 26–November 25 less the Kern River spot price for the same period. Assuming the WTI value is $29.00 per barrel and the Kern River value is $20.00 per barrel, the negative $9.00 per barrel differential would be added to the NYMEX calendar month average price corresponding to the month of production (without weekends or holidays). Using the same NYMEX value, $29.50 per barrel, as in the previous example, the royalty value calculation would be as follows:

(Trading month CA spot oil assessment − Spot WTI assessment) + NYMEX calendar month average ($20 − $29) + $29.50 = $20.50 applied to all December royalty volumes that are valued as not sold under an arm's-length contract.

Because the proposed new valuation method uses new oil types and locations as its basis, location and quality adjustments must be made to the current basis (ANS) to make a meaningful comparison of values calculated under the proposed and current rules. Estimating the proper adjustments with precision is very difficult.

For example, again using Kern River crude oil to compare to ANS, there are significant differences in quality (13.4 degrees for Kern River and 29.5 for ANS) and in location (Kern County, CA and Long Beach, CA). The sulfur content of the two oils is nearly identical, so no sulfur price adjustment is needed. Gravity differential estimates can vary significantly because California posted price adjustment scales vary from $0.15 per degree API gravity to $0.25 per degree or more. The gravity adjustment range would then be from $2.42 to $4.03 per barrel.

The location differential can be estimated by the use of a tariff between points in Kern County to Long Beach. These tariffs currently range between $.75 and $1.25 per barrel.

Depending on how these differentials apply in specific cases, the result could be deductions from the ANS price from $3.17 to $5.28 per barrel in order to compare the adjusted ANS price to value calculated under the proposed rule. The result could be an overall royalty increase or decrease. Applying the high gravity and location adjustments above to the ANS price from 1999 through 2002 would result in an adjusted ANS price about $1.00 per barrel lower than the price derived under the proposed rule. Applying the low gravity and location adjustments to the ANS price would result in a value about $1.00 above the price derived under the proposed rule.

In estimating the impact of a change to NYMEX valuation, we made several assumptions in addition to the $1.00 per barrel increase or decrease. For California we assumed that 50 percent of all Federal barrels would be valued under the non-arm's-length provisions, that the offshore royalty rate is one-sixth and onshore royalty rate is one-eighth, and that volumes taken in kind in the small refiner program are 10,000 barrels per day. We then subtracted the volumes taken in kind and applied the $1.00 per barrel figure to the remaining barrels assumed to be valued under the non-arm's-length provisions. We estimate a range of −$2,120,650 to +2,120,650 per year in terms of higher or lower royalty payments. This range results because the location and quality adjustments can vary significantly. For Alaska we based our estimate on an average offshore royalty production of 1,600 barrels per day, and we assumed that all production would be valued under the non-arm's-length provisions. Using the same $1.00 per barrel figure that we used in California, we estimate a range of −$584,000 to +584,000 per year in terms of higher or lower royalty payments.

Rocky Mountain Region

Determining the impact of any proposed modification of the current pricing methodology for valuing oil not sold at arm's-length in the Rocky Mountain Region is also difficult. This is largely because there is no prescribed formula currently in place, but rather a series of benchmark procedures that lessees apply on an individual basis. Although this proposal does involve NYMEX pricing, it would apply only if and when the first two benchmark procedures (which rely exclusively on arm's-length values) are inapplicable. Where the third benchmark applies, valuation of Wyoming Sweet would rely on differentials between WTI at Cushing, Oklahoma, and Wyoming Sweet at Guernsey, Wyoming.

The proposed Wyoming Sweet valuation methodology is identical to that for California, with the obvious substitution of the Wyoming Sweet spot price for the California grades. For December production, the average value of Wyoming Sweet against WTI determined October 26th through November 25th applied to the NYMEX calendar month average becomes the basis of value:

(Trading month WY Sweet spot oil assessment − Spot WTI assessment) + NYMEX calendar month average.

We have compared prices under NYMEX adjusted for the grade differential (and not the "roll," as discussed earlier) with prices calculated under the existing rule based on spot prices at Guernsey, Wyoming—the only market center in the Rocky Mountain Region. We used the same time period, April 2000 through December 2002, as we did for the Rest of the Country (see footnote 3). Over this period the monthly average spot price exceeded the adjusted average monthly NYMEX price by about $0.04 per barrel. We have also performed this comparison back to the beginning of 1999 and find that the adjusted NYMEX price exceeded the monthly average spot price by about $0.02 per barrel over the entire period January 1999 through December 2002. To illustrate the highest potential cost to industry, we chose the $0.02 per barrel increment of NYMEX over spot as the basis for our benefit and cost estimates.

In estimating the impact of a change to NYMEX valuation, we made several assumptions in addition to the $0.02 per barrel increment. First we assumed that 50 percent of all Federal barrels would be valued under the non-arm's-length provisions. Then, because there are four non-arm's-length benchmarks in the Rocky Mountain Region and only the third benchmark would rely on NYMEX prices, we assumed that 25 percent of all Federal barrels that are valued under the benchmarks would be valued under each of the benchmarks and hence only 25 percent of those barrels would rely on NYMEX prices. (None of the other three benchmarks would change.) Thus 12½ percent of all Federal barrels would be valued under the third non-arm's-length benchmark. We also assumed that the royalty rate is one-eighth, and that volumes taken in kind (these are from Wyoming only) would be about 4,000 barrels per day. We then subtracted the volumes taken in kind and applied the $0.02 per barrel figure to the remaining barrels assumed to be valued under the non-arm's-length provisions. We estimate higher royalty payments to be about $11,738 per year.

(2) Expected Royalty Reduction—

(i) Increase Rate of Return in Non-Arm's-Length Situations From 1 Times the Standard and Poor's BBB Bond Rate to 1.5 times the Standard and Poor's BBB Bond Rate

The MMS does not routinely collect detailed allowance information, such as affiliation between the payor and transporter or the cost components used to calculate a non-arm's-length allowance rate. Therefore we had to make several broad assumptions in order to estimate the impact of the proposed rule. We assumed that 50 percent of all allowances are non-arms-length. We also assumed that over the life of the pipeline, allowance rates are made up of ⅓ rate of return on undepreciated capital investment, ⅓ depreciation expenses and ⅓ operation, maintenance and overhead expenses. During FY 2001 royalty payors reported transportation allowance deductions of $45,363,394 for Federal oil production. Based on our assumptions, if ½ of the allowance deductions are non-arm's-length, then $22,681,697 of the total allowances fell in this category. If ⅓ of the allowance is made up of the rate of return, this equals $7,560,565. Therefore, we estimated that increasing the basis for the rate of return by 50 percent could result in additional allowance deductions of $3,780,283 ($7,560,565 × .50). Our review of transportation allowances deducted from oil royalties in the States of Wyoming, Colorado, Utah, and New Mexico revealed minimal amounts deducted from onshore leases. Therefore, we assumed that this entire increase would impact offshore royalties only.

(ii) Allow Line Loss as a Component of a Non-Arm's-Length Transportation Allowance

For offshore production, we based this estimate on the total offshore oil royalties for FY 2001 of $2,069,450,791. We assumed that 50 percent of all allowances are non-arms-length, and that oil pipeline losses are 0.2 percent of the volume of the production. Therefore, before making the further adjustments discussed below, we estimated this change could result in additional transportation allowances of $2,069,451 per year ($2,069,450,791 × .50 × .002). For onshore production we used total onshore oil royalties for FY 2001 of $252,575,890. We assumed that 50 percent of all allowances are non-arm's-length, and that oil pipeline losses are 0.2 percent of the volume of the production. Therefore, before making the further adjustments discussed below, we estimated this change could result in additional transportation allowances of $252,576 per year ($252,575,890 × .50 × .002).

We also needed to recognize that substantial volumes of offshore production are taken in kind and are not subject to the regulations regarding transportation. We estimated that between 50,000 barrels of oil per day (BOPD) and 180,000 BOPD may be taken in kind. The wide variance in this estimate is caused by the approximately 130,000 BOPD which may be taken in kind and placed into the Strategic Petroleum Reserve. Based on daily offshore Federal production of 222,100 BOPD, the amount of oil transportation subject to these regulations could range from a high of 77 percent of the production to a low of 19 percent of the production. [(222,100 − 50,000) / 222,100 = 77%; (222,100 − 180,000) / 222,100 = 19%]. Applying the high and low range factors for oil taken in kind, this could result in additional transportation allowance deductions for offshore leases ranging from $393,196 ($2,069,451 × 19%) to $1,593,477 ($2,069,451 × 77%) per year.

(iii) Allow Quality Bank Administration Fees As a Component of an Arm's-Length and a Non-Arm's-Length Transportation Allowance

For offshore oil production, we based our estimate on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We also estimated that quality bank administrative fees were $0.002 per barrel. We estimated that allowing such fees could result in additional offshore transportation allowances of $162,133 (81,066,567 × $0.002) per year before considering the effects of oil taken in kind. Applying the high and low range factors for oil taken in kind, this could result in additional transportation allowance deductions ranging from $30,805 ($162,133 − 19%) to $124,842 ($162,133 − 77%) per year. For onshore production we used the onshore royalty volume for FY 2001 of 9,496,181 barrels. Allowing such fees could result in additional allowances of $18,992 (9,496,181 × $0.002)

(iv) Allow Line Fill As a component of an Arm's-Length and a Non-Arm's-Length Transportation Allowance

For offshore oil production, we based this estimate on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We estimated that line fill costs ranged from $0.02 to $0.05 per barrel. We then estimated that this factor could result in additional transportation allowances of $1,621,331 (81,066,567 × $0.02) to $4,053,328 (81,066,567 × $0.05) before considering the effects of oil taken in kind. Applying the high and low range factors for oil taken in kind, this could result in additional offshore transportation allowance deductions ranging from $308,052 ($1,621,331 × 19%) to $3,121,062 ($4,053,328 × 77%) per year. For Onshore production we estimated that this factor could result in additional transportation allowances of $189,924 (9,496,181 × $0.02) to $474,809 (9,496,181 × $0.05).

Allow the Cost of a Letter of Credit As a Component of an Arm's-Length Transportation Allowance

Again we assumed that 50% of allowances were at arm's length. We again based the estimate on the total offshore oil royalty volume for FY 2001 of 81,066,567 barrels. We estimated that letter of credit costs ranged from $0.02 to $0.05 per barrel. We thus estimated that this could result in additional transportation allowances of $810,666 (81,066,567 × $0.02 × .5) to $2,026,664 (81,066,567 × $0.05 × .5). Applying the high and low range factors for oil taken in kind, this could result in additional offshore transportation allowance deductions ranging from $154,027 ($810,666 × 19%) to $1,560,531 ($2,026,664 × 77%) per year. For Onshore production we estimated that this factor could result in additional transportation allowances of $94,962 (9,496,181 × $0.02 ×.5) to $237,405 (9,496,181 × $0.05 × .5).

(vi) Royalty Reduction Summary, items (i)–(v)—Additional Deductions for Allowances

We estimate that between $4,666,363 and $10,180,195 in additional transportation allowances could be deducted from OCS lease royalties based on an increased rate of return and permissibility of line losses for non-arm's-length allowances; permissibility of quality bank administration fees and line fill costs for both arm's-length and non-arm's-length allowances; and permissibility of letter of credit costs for arm's-length allowances. Also, for these same items we estimate that between $556,454 and $983,782 of additional transportation allowances may be deducted from Onshore Federal lease royalties.

(3) Cost—Administration—

(i) System Modifications To Reflect NYMEX Pricing Basis

We believe any increases in administrative costs related to changes in non-arm's-length valuation procedures would be minimal. These procedures involve NYMEX prices, which are readily available at no cost from numerous sources. They also involve determination of spot price differentials at various locations. We believe that anyone who uses the non-arm's-length provisions of the current rule already has access to the needed publications and exchange agreements. For some lessees, modification of computer programs related to royalty calculation and payment may be needed. We think that only about 50 of the approximately 800 Federal oil royalty payors would use the non-arm's-length provisions and thus might need to do some reprogramming. Using an estimated cost of $5,000 for each such payor to do its reprogramming, the added one-time cost would be $250,000.

(ii) Proposal of a Location Differential Under 206.112(c)(1))

We anticipate that, in a very few cases, companies may request approval of proposed differentials when less than 20 percent of the crude oil is transported or exchanged from the lease. These 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, including informing MMS of any changes to relevant facts that occur before MMS responds to their request; (4) include copies of all relevant documents; (5) provide the company's analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) suggest the proposed differential. We estimate that there will be two such requests annually. We estimate the annual burden for these requests would be 660 hours (2 × 330), including record keeping. Based on a per-hour cost of $50, we estimate the cost to industry is $33,000.

B. State and Local Governments

This rule will not impose any additional burden on local governments. MMS estimates that States impacted by this rule may experience changes in royalty collections as indicated below:

(1) Expected Increased Royalty Revenues

States receiving revenues from offshore Outer Continental Shelf Lands Act Section 8(g) leases would share in a portion of the estimated additional $4,303,913 to $11,658,663 in royalties that would accrue annually from the "rest of the country" under the proposed valuation methodology. Based on each 8(g) State's share of total offshore royalties for FY 2001 and their 8(g) disbursement percentage, we estimate the States' 8(g) share to be between $26,363 and $71,119. Onshore States would receive additional revenue of $317,682.

The State of California would share in a portion of the estimated $2,120,650 increase to $2,120,650 decrease in royalties accruing from California. We estimate that royalties accruing to the State of California for onshore production would range from an increase of about $524,317 to a decrease of about $524,317. We further estimate that its 8(g) share would range from an increase of about $53,692 to a decrease of about $53,692. For Alaska we estimate that its 8(g) share would range from an increase of about $157,680 to a decrease of about $157,680, with no onshore impact. For the Rocky Mountain Region, we estimate an increase in the States' share of royalty revenues of about $5,869 per year.

(2) Expected Royalty Decreases—Increased Rate of Return and Inclusions of Line Loss, Quality Bank Administration Fees, Line Fill and Letters of Credit as Components of Allowance Costs

We estimate that between $33,785 and $73,705 in additional transportation allowances may be deducted from the States' share of Federal royalties for OCS 8(g) leases. In addition, we estimate that between $278,227 and $491,891 may be deducted from the States' share of onshore Federal lease royalties.

C. Federal Government

Because many of the changes in the proposed rule are technical clarifications and others are relatively minor changes to the valuation mechanisms, the impacts to the Federal Government should be minimal, especially in administration.

(1) Expected Royalty Increase—From Use of NYMEX Pricing

The Federal Government would receive an estimated $4,303,913, to $11,658,663 in royalties each year from the "rest of the country," of which affected States would receive a portion. We estimate the Federal share of offshore royalties to be between $3,642,186 and $10,952,180 and the Federal share of onshore royalties at $317,682. For California we estimate the range of royalty impacts to be from a decrease of $1,542,630 to an increase of $1,542,630 per year. For Alaska, we estimate the range of royalty impacts to be from a decrease of $426,320 to an increase of $426,320 per year. For the Rocky Mountain Region, we estimate an increase in royalty revenues of about $5,869 per year of the estimated additional $11,738 in royalties accruing to production from the affected States.

(2) Expected Royalty Decreases—Increased Rate of Return and Inclusions of Line Loss, Quality Bank Administration Fees, Line Fill and Letters of Credit as Components of Allowance Costs

We estimate that between $4,632,578 and $10,106,490 per year in additional transportation allowances may be deducted from Federal OCS royalties and between $278,227 and $491,891 from onshore royalties.

(3) Cost—Proposal of a Location Differential Uunder 206.112(c)

We anticipate that companies may request approval of proposed differentials when they transport or exchange less than 20 percent of the crude oil from the lease. In processing these requests MMS would have to: (1) Respond in writing; (2) verify 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; (4) obtain copies of all relevant documents; (5) analyze the issue(s), including citations to all relevant precedents (including adverse precedents); and (6) potentially defend our determination. For the above written requests, we estimate that there will be two responses annually. We estimate that the annual burden for these requests is 660 hours (2 × 330), including record keeping. Based on a per-hour cost of $50, we estimate the cost to the Federal Government is $33,000.

D. Summary of Royalty Impacts and Costs to Industry, State and Local Governments, and the Federal Government.

In the table, a negative numbers means a reduction in payment or receipt of royalties or a reduction in costs. A positive number means an increase in payment or receipt of royalties or an increase in costs. For the purpose of calculation of the net expected change in royalty impact, we have assumed that the average for royalty increases or decreases would be the midpoint of the proposed range.

SUMMARY OF COSTS AND ROYALTY IMPACTS

Description	Costs and royalty increases or royalty decreases	
	First year	Subsequent years
A. Industry		
(1) Royalty Increase based on using the revised NYMEX pricing.	Rocky Mtn Region: $11,738 California: −$2,120,650 to $2,120,650 Alaska: −$584,000 to $584,000 Rest of Country: −$4,303,913 to $11,658,663	Rocky Mountain Region: $11,738. California: −$2,120,650 to $2,120,650. Alaska: −$584,000 to $584,000. Rest of Country: −$4,303,913 to $11,658,663.
(2) Royalty Decrease—Increased Allowable Costs.	−$5,222,817 to −$11,163,977	−$5,222,817 to −$11,163,977.
(3) Net Expected Change in Royalty Payments from Industry.	−$200,371	−$200,371.
(4) Expected Range of Royalty Impact	−$9,552,976 to $9,152,234	−$9,552,976 to $9,152,234.
(5) Administrative Cost—reprogramming of systems and submitting location differential requests.	$283,000	$33,000.
B. State and Local Governments		
(1) Royalty Increase—increased royalty revenue in terms of the States' share of Federal royalties.	Rocky Mtn. Region: $5,869 California: −$578,009 to $578,009 Alaska: −$157,680 to $157,680 Rest of Country: $344,045 to $388,801	Rocky Mtn. Region: $5,869. California: −$578,009 to $578,009. Alaska: −$157,680 to $157,680. Rest of Country: $344,045 to $388,801.
(2) Royalty Decrease—Increased Allowable Costs in terms of the States' share of Federal royalties.	8(g) States: −$33,785 to −$73,705 All Other States: −$278,227 to −$491,891	8(g) States: −$33,785 to −$73,705. All Other States: −$278,227 to −$491,891.
(3) Net Expected Change to Royalty Payments to States.	−$66,512	−$66,512.
(4) Expected Range of Royalty Impact	−$951,371 to $818,347	−$951,371 to $818,347.
C. Federal Government		
(1) Royalty Increase—increased royalty revenues net of the States' share.	Rocky Mtn Region: $5,869 California: −$1,542,630 to $1,542,630 Alaska: −$426,320 to $426,320 Rest of Country: $3,959,868 to $11,269,862	Rocky Mtn Region: $5,869. California: −$1,542,630 to $1,542,630. Alaska: −$426,320 to $426,320. Rest of Country: $3,959,868 to $11,269,862.
(2) Royalty Decrease—Increased Allowable Costs net of the States' share.	−$4,910,805 to −$10,598,381	−$4,910,805 to −$10,598,381.
(3) Net Expected Change in Royalty Payment to the Federal Government.	−$133,859	−$133,859.
(4) Expected Range of Royalty Impacts	−$8,601,605 to $8,333,887	−$8,601,605 to $8,333,887.
(5) Cost of administrating location differential requests.	$33,000	$33,000.

3. Regulatory Planning and Review, Executive Order 12866

In accordance with the criteria in Executive Order 12866, this proposed rule is not an economically significant regulatory action as it does not exceed the $100 million threshold. The Office of Management and Budget (OMB) has made the determination under Executive Order 12866 to review this proposed rule because it raises novel legal or policy issues.

1. This proposed rule will not have an annual effect of $100 million or adversely affect an economic sector, productivity, jobs, the environment, or other units of Government. MMS has evaluated the costs of this rule, and estimates that industry would incur additional administrative costs of approximately $283,000 in the first year of implementation, and $33,000 in additional administrative costs in subsequent years. The Federal Government would incur $33,000 each year in additional administrative costs.

2. This proposed rule will not create inconsistencies with other agencies' actions.

3. This proposed rule will not materially affect entitlements, grants, user fees, loan programs, or the rights and obligations of their recipients.

4. This proposed rule will raise novel legal or policy issues. See proposed modifications in the *Provisions of This Proposed Rule* in the attached Threshold Analysis.

4. Regulatory Flexibility Act

I certify that this proposed rule will not have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). An initial Regulatory Flexibility Analysis is not required. Accordingly, a Small Entity Compliance Guide is not required. See the above Analysis titled ''Summary of Costs and Royalty Impacts.''

Your comments are important. The Small Business and Agricultural 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 business. If you wish to comment on the enforcement actions in this rule, call 1–800–734–3247. You may comment to the Small Business Administration without fear of retaliation. Disciplinary action for retaliation by an MMS employee may include suspension or termination from employment with the Department of the Interior.

5. Small Business Regulatory Enforcement Act (SBREFA)

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

1. Does not have an annual effect on the economy of $100 million or more. See the above Analysis titled ''Summary of Costs and Royalty Impacts.''
2. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.
3. Does 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.

6. Unfunded Mandates Reform Act

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*):

1. This proposed rule will not significantly or uniquely affect small governments. Therefore, a Small Government Agency Plan is not required.
2. This proposed rule will not produce a Federal mandate of $100 million or greater in any year; *i.e.*, it is not a significant regulatory action under the Unfunded Mandates Reform Act. The analysis prepared for Executive Order 12866 will meet the requirements of the Unfunded Mandates Reform Act. See the above Analysis titled ''Summary of Costs and Royalty Impacts.''

7. Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings), Executive Order 12630

In accordance with Executive Order 12630, this proposed rule does not have significant takings implications. A takings implication assessment is not required.

8. Federalism, Executive Order 13132

In accordance with Executive Order 13132, this proposed rule does not have federalism implications. A federalism assessment is not required. It will not substantially and directly affect the relationship between the Federal and State governments. 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 proposed rule would not alter any lease management or royalty sharing provisions. It would determine the value of production for royalty computation purposes only. This proposed rule would 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 proposed rule would not alter that relationship.

9. Civil Justice Reform, Executive Order 12988

In accordance with Executive Order 12988, the Office of the Solicitor has determined that this proposed rule will not unduly burden the judicial system and does not meet the requirements of sections 3(a) and 3(b)(2) of the Order.

10. Paperwork Reduction Act of 1995

This proposed rule contains new information collection requirements that we have submitted to the Office of Management and Budget (OMB) for review and approval under section 3507(d) of the Paperwork Reduction Act of 1995. As part of our continuing effort to reduce paperwork and respondent burden, we invite the public and other Federal agencies to comment on any aspect of the reporting burden.

Submit your comments by fax (202) 395–6566 or e-mail (*OIRA_docket@omb.eop.gov*) to the Office of Information and Regulatory Affairs, OMB, Attention Desk Officer for the Department of the Interior (OMB Control Number 1010–NEW).

Send copies of your comments to Sharron L. Gebhardt, Regulatory Specialist, Records and Information Management Team, Minerals Management Service, Minerals Revenue Management, P.O. Box 25165, MS 320B2, Denver, Colorado 80225. If you use an overnight courier service, the MMS courier address is Building 85, Room A–614, Denver Federal Center, Denver, Colorado 80225. You may also e-mail your comments to us at *mrm.comments@mms.gov*. Include the title of the information collection and the OMB Control number in the ''Attention'' line of your comment. Also include your name and return address. Submit electronic comments as an ASCII file avoiding the use of special characters and any form of encryption. If you do not receive a confirmation that we have received your e-mail, contact Ms. Gebhardt at (303) 231–3211.

OMB has up to 60 days to approve or disapprove this collection of information but may respond after 30 days. Therefore, public comments should be submitted to OMB within 30 days in order to assure their maximum consideration. However, we will consider all comments received during the comment period for this notice of proposed rulemaking.

Information Collection Burden

The annual reporting burden is 1608 hours. We expect approximately 40 responses from 7 Federal lessees to submit the required information. The burden estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Using an average cost of $50 per hour, the total cost to respondents is $80,400.

Proposed 30 CFR part 206 subpart C	Reporting and recordkeeping requirements	Burden hours per responses	Annual number of responses	Annual burden hours
206.103(b)(4)	If you demonstrate to MMS's satisfaction that paragraphs (b)(1) through (b)(3) 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.	330	1	330
206.112(a)(2)(ii) ..	For oil that you exchange between your lease and the market center (or between any intermediate points between those locations) under an exchange agreement that is not at arm's length, you must obtain approval from MMS for a location and quality differential.	330	1	330
206.112(c)(1)	If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to MMS a differential between the lease and the market center for the portion of the oil that you do not transport or exchange * * *.	330	2	660

Proposed 30 CFR part 206 subpart C	Reporting and recordkeeping requirements	Burden hours per responses	Annual number of responses	Annual burden hours
210.53(c)(1) and (2).	On the Form MMS–2014, the operator must report the following information on separate lines: (1) The share of the production the operator purchased from each working interest owner and the associated royalty payment; and (2) The operator's own share of production and the associated royalty payment.	8	36	288
Total	....	....	40	1608

Public Comment Policy. The PRA (44 U.S.C. 3501, *et seq.*) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Before submitting an ICR to OMB, PRA Section 3506(c)(2)(A) requires each agency ''* * * to provide notice * * * and otherwise consult with members of the public and affected agencies concerning each proposed collection of information * * *.'' Agencies must specifically solicit comments to: (a) Evaluate whether the proposed collection of information is necessary for the agency to perform its duties, including whether the information is useful; (b) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) enhance the quality, usefulness, and clarity of the information to be collected; and (d) minimize the burden on the respondents, including the use of automated collection techniques or other forms of information technology.

The PRA also requires agencies to estimate the total annual reporting ''non-hour cost'' burden to respondents or recordkeepers resulting from the collection of information. We have not identified non-hour cost burdens for this information collection. If you have costs to generate, maintain, and disclose this information, you should comment and provide your total capital and startup cost components or annual operation, maintenance, and purchase of service components. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and startup costs include, among other items, computers and software you purchase to prepare for collecting information; monitoring, sampling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: (i) Before October 1, 1995; (ii) to comply with requirements not associated with the information collection; (iii) for reasons other than to provide information or keep records for the Government; or (iv) as part of customary and usual business or private practices.

We will summarize written responses to this proposed information collection and address them in our final rule. We will provide a copy of the ICR to you without charge upon request and the ICR will also be posted on our Web site at *http://www.mrm.mms.gov/Laws_R_D/FRNotices/FRInfColl.htm*.

We will post all comments in response to this proposed information collection on our Web site at *http://www.mrm.mms.gov/Laws_R_D/InfoColl/InfoColCom.htm_*. We will also make copies of the comments available for public review, including names and addresses of respondents, during regular business hours at our offices in Lakewood, Colorado. Individual respondents may request that we withhold their home address from the public record, which we will honor to the extent allowable by law. There also may be circumstances in which we would withhold from the rulemaking record a respondent's identity, as allowable by law. If you request that we withhold your name and/or address, state this prominently at the beginning of your comment. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

11. National Environmental Policy Act

This proposed rule deals with financial matters and has no direct effect on Minerals Management Service decisions on environmental activities. Pursuant to 516 DM 2.3A (2), Section 1.10 of 516 DM 2, Appendix 1 excludes from documentation in an environmental assessment or impact statement ''policies, directives, regulations and guidelines of an administrative, financial, legal, technical or procedural nature; or the environmental effects of which are too broad, speculative or conjectural to lend themselves to meaningful analysis and will be subject later to the NEPA process, either collectively or case-by-case.'' Section 1.3 of the same appendix clarifies that royalties and audits are considered to be routine financial transactions that are subject to categorical exclusion from the NEPA process.

12. Government-to-Government Relationship with Tribes

In accordance with the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments ''(59 FR 22951) and 512 DM 2, we have evaluated potential effects on Federally recognized Indian tribes and have determined that the changes we are proposing for Federal leases may have an impact on Indian leases. As such, by **Federal Register** Notice (68 FR 7086) dated February 12, 2003, MMS reopened the comment period on the January 2000 supplementary proposed rule for valuing crude oil produced from Indian leases. The comment period closed on April 14, 2003. MMS will determine how to proceed with that rulemaking based on comments received.

13. Effects on the Nation's Energy Supply, Executive Order 13211

In accordance with Executive Order 13211, this regulation does not have a significant effect on the nation's energy supply, distribution, or use. The proposed changes better reflect the way industry accounts internally for its oil valuation and provides a number of technical clarifications. None of these changes should impact significantly the way industry does business, and accordingly should not affect their approach to energy development or marketing. Nor does the proposed rule otherwise impact energy supply, distribution, or use.

14. Consultation and Coordination With Indian Tribal Governments, Executive Order 13175

In accordance with Executive Order 13175, this proposed rule does not have tribal implications that impose substantial direct compliance costs on Indian tribal governments

15. Clarity of This Regulation

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this rule easier to understand, including answers to questions such as the following: (1) Are the requirements in the rule clearly stated? (2) Does the rule contain technical language or jargon that interferes with its clarity? (3) Does the format of the 56 rule (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity? (4) Would the rule be easier to understand if it were divided into more (but shorter) sections? (A ''section'' appears in bold type and is preceded by the symbol ''§ '' and a numbered heading; for example, § 204.200 What is the purpose of this part?) (5) Is the description of the rule in the **SUPPLEMENTARY INFORMATION** section of the preamble helpful in understanding the proposed rule? What else could we do to make the rule easier to understand?

Send a copy of any comments that concern how we could make this rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street NW., Washington, DC 20240. You may also e-mail the comments to this address: *Exsec@ios.doi.gov*.

List of Subjects in 30 CFR Parts 206 and 210

Continental shelf, Government contracts, Mineral royalties, Natural gas, Petroleum, Public lands—mineral resources, Reporting and recordkeeping requirements.

Dated: June 23, 2003.

Rebecca W. Watson,

Assistant Secretary for Land and Minerals Management.

For the reasons set forth in the preamble, subpart C of part 206 and subpart B of part 210 of title 30 of the Code of Federal Regulations are amended as follows:

1. The authority for part 206 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396, 396a *et seq.*, 2101 *et seq.*; 30 .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. Section 206.101 is amended as follows:

A. In the definition of ''affiliate'' in paragraph (2), the words ''between 10 and 50 percent'' are removed and the words ''10 through 50 percent'' are added in their place.

B. The definition of ''index pricing'' is removed.

C. The definition of ''index pricing point'' is removed.

D. The definition of ''MMS-approved publication'' is revised.

E. A new definition of ''NYMEX price'' is added in alphabetical order.

F. A new definition of ''prompt month'' is added in alphabetical order.

G. A new definition of ''roll'' is added in alphabetical order.

H. The definition of ''spot price'' is removed.

I. The definition of ''trading month'' is revised.

J. A new definition of ''WTI differential'' is added in alphabetical order.

The additions and revisions to § 206.101 read as follows:

§ 206.101. What definitions apply to this subpart?

* * * * *

MMS-approved publication means a publication MMS approves for determining WTI differentials.

* * * * *

NYMEX price means the average of the New York Mercantile Exchange (NYMEX) settle prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows:

(1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the prompt month corresponding to each such day; and

(2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

* * * * *

Prompt month means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

* * * * *

Roll means an adjustment to the NYMEX price that is calculated as follows:

Roll = $.6667 \times (P_0 - P_1) + .3333 \times (P_0 - PP_2)$,

where: P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month; P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1—Falling Market:* The month of production for which you must determine royalty value is March. March was the prompt month (for year 2003) from January 22 through February 20. April is the first month following the month of production, and May is the second month following the month of production. P_O therefore is the average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 22 and February 20. P_1 is the average of the daily NYMEX settlement prices for deliveries during April published for each business day between January 22 and February 20. P_2 is the average of the daily NYMEX settlement prices for deliveries during May published for each business day between January 22 and February 20. In this example, assume that P_O = \$28.00 per bbl, P_1 = \$27.70 per bbl, and P_2 = \$27.10 per bbl. In this example (a declining market), Roll = .6667 − (\$28.00 − \$27.70) + .3333 − (\$28.00 − 27.10) = \$.20 + \$.30 = \$.50. You add this number to the NYMEX price.

(2) *Example 2—Rising Market:* The month of production for which you must determine royalty value is July. July 2003 is the prompt month from May 21 through June 20. August is the first month following the month of production, and September is the second month following the month of production. P_O therefore is the average of the daily NYMEX settlement prices for deliveries during July published for each business day between May 21 and June 20. P_1 is the average of the daily NYMEX settlement prices for deliveries during August published for each business day between May 21 and June 20. P_2 is the average of the daily NYMEX settlement prices for deliveries during September published for each business day between May 21 and June 20. In this example, assume that P_O = \$28.00 per bbl, P_1 = \$28.90 per bbl, and P_2 = \$29.50 per bbl. In this example (a rising market), Roll = .6667 × (\$28.00 − \$28.90) + .3333 × (\$28.00 − \$29.50) = (− \$.60) + (− \$.50) = − \$1.10. You add this negative number to the NYMEX

price (effectively a subtraction from the NYMEX price).

* * * * *

Trading month means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, www.nymex.com, in which case the NYMEX definition will apply.

* * * * *

WTI differential means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma, published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

Example. Assume the production month is March 2003. Industry trade publications perform their price surveys and determine differentials during January 26 through February 25 for oil delivered in March. (California is an exception. In California, the survey covers the calendar month of February for March deliveries.) The WTI differential (for example, the West Texas Sour crude at Midland, Texas, spread versus WTI) applicable to valuing oil produced in the March 2003 production month would be determined using all the business days for which differentials are published during the period January 26 through February 25.

3. In § 206.103, paragraph (e) is amended as follows:

A. The paragraph heading is revised to read ''Production delivered to your refinery and NYMEX price is an unreasonable value.''

B. In paragraph (e)(1)(ii), the words ''an index price'' are removed and the words ''the NYMEX price'' are added in their place.

C. In paragraph (e)(1)(iii), the words ''the index price'' are removed and the words ''the NYMEX price'' are added in their place, and paragraphs (a) through (d) are revised to read as follows:

§ 206.103. How do I value oil that is not sold under an arm's-length contract?

* * * * *

(a) *Production from leases in California or Alaska.* Value is the NYMEX price, adjusted for applicable location and quality differentials and transportation costs under § 206.112.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph (b) provides methods and options for valuing your production under different factual situations. You must consistently apply paragraph (b)(1) or (b)(2) or (b)(3) 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.

(1) If you have an MMS-approved tendering program, you must value oil produced from leases in the area the tendering program covers at the highest winning bid price for tendered volumes.

(i) The minimum requirements for MMS to approve your tendering program are:

(A) 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; and

(B) You 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.

(ii) If you do not have an MMS-approved tendering program, you may elect to value your oil under either paragraph (b)(2) or (b)(3) of this section. After you select either paragraph (b)(2) or (b)(3) 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) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) 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.

(ii) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliates' arm's-length purchases or sales to the same gravity as that of the oil produced from the lease.

(3) Value is the NYMEX price, adjusted for applicable location and quality differentials and transportation costs under § 206.112.

(4) If you demonstrate to MMS'' satisfaction that paragraphs (b)(1) through (b)(3) 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 NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under § 206.112.

(2) If the MMS Director determines that use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula used by industry to calculate the roll changes, MMS may terminate or modify use of the roll under paragraph (c)(1) of this section at the end of each 2-year period following [EFFECTIVE DATE OF THE FINAL RULE] through notice published in the **Federal Register** not later than 60 days before the end of the 2-year period. MMS will explain the rationale for terminating or modifying the use the roll in this notice.

(d) *Unreasonable NYMEX-based value.* If MMS determines that the NYMEX price does not represent a reasonable royalty value in any particular case, MMS may establish reasonable royalty value based on other relevant matters.

* * * * *

4.–5. In § 206.104, the section heading and paragraphs (a) introductory text, (a)(3), (c), and (d) are revised to read as follows:

§ 206.104. What publications are acceptable to MMS?

(a) MMS periodically will publish in the **Federal Register** a list of acceptable publications based on certain criteria, including, but not limited to:

* * * * *

(3) Publications that use adequate survey techniques, including development of estimates based on daily

surveys of buyers and sellers of crude oil; and

* * * * *

(c) MMS will reference the tables you must use in the acceptable publications.

(d) MMS may revoke its approval of a particular publication if it determines that the prices or differentials published in the publication do not accurately represent market values or differentials.

6. In § 206.109, paragraph (b) is revised to read as follows:

§ 206.109. When may I take a transportation allowance in determining value?

* * * * *

(b) *Transportation allowances and other adjustments that apply when value is based on NYMEX prices.* If you value oil using the NYMEX price under § 206.103, MMS will allow an adjustment for certain location and quality differentials and certain costs associated with transporting oil as provided under § 206.112.

* * * * *

7. Section 206.110 is amended by:

A. In paragraph (a), in the first sentence, removing the words ''under that contract'' and adding in their place the words ''as more fully explained in paragraph (b) of this section.''

B. Redesignating paragraphs (b) through (e) as paragraphs (d) through (g).

C. Adding new paragraphs (b) and (c) to read as follows:

§ 206.110. How do I determine a transportation allowance under an arm's-length transportation contract?

* * * * *

(b) You may deduct any of the following actual costs incurred for transporting oil. You may not use as a deduction any cost that duplicates all or part of any other cost that you use under this paragraph:

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid to a pipeline owner for administration of a quality bank.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(i) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 206.102 or § 206.103, as applicable; and

(ii) Multiply the value calculated under paragraph (b)(4)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 206.111(i)(2) by 12.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(10) Costs of securing a letter of credit, or other surety, that the pipeline requires a shipper to maintain.

(c) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

* * * * *

8. Section 206.111 is amended by:

A. Revising the section heading and paragraph (a).

B. Revising paragraph (b) introductory text and adding new paragraphs (b)(6) and (b)(7).

C. In paragraph (h)(5), removing the words ''who owned the system on June 1, 2000'' and adding in their place the words ''from whom you bought the system. Include in the depreciation schedule any subsequent reinvestment.''

D. In paragraph (i)(2), in the first sentence, adding the words ''1.5'' before the words ''the industrial bond yield index for Standard and Poor's BBB rating.''

The revisions and additions to the section heading and paragraphs (a) and (b) read as follows: § 206.111. How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?

(a) This section applies if you or your affiliate do not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. Calculate your transportation allowance based on your or your affiliate's reasonable, actual costs for transportation during the reporting period using the procedures prescribed in this section.

(b) Your or your affiliate's actual costs include:

* * * * *

(6) To the extent not included in costs identified in paragraphs (d) through (j) of this section, you may also deduct the following actual costs. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(i) Volumetric adjustments for actual (not theoretical) line losses.

(ii) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(A) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under § 206.102 or § 206.103, as applicable; and

(B) Multiply the value calculated under paragraph (b)(6)(ii)(A) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 206.111(i)(2) by 12.

(iii) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(iv) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(v) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(7) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(i) Fees paid for long-term storage (more than 30 days).

(ii) Administrative, handling, and accounting fees associated with terminalling.

(iii) Title and terminal transfer fees.

(iv) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(v) Fees paid to brokers.

(vi) Fees paid to a scheduling service provider.

(vii) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(viii) Theoretical line losses.

(ix) Gauging fees.

* * * * *

9. Section 206.112 is revised to read as follows:

§ 206.112. What adjustments and transportation allowances apply when I value oil production from my lease using the NYMEX price?

This section applies when you use the NYMEX price to calculate the value of production under § 206.103. As specified in this section, adjust the NYMEX price to reflect the difference in value between your lease and Cushing, Oklahoma.

(a) If you transport or exchange (or both transport and exchange) all or a portion of the oil produced from your lease to a market center, adjust the NYMEX price for that oil under paragraph (a)(1) or (a)(2) of this section, or both, as applicable. If you further exchange your oil at arm's length from the market center to Cushing, Oklahoma, use paragraph (a)(3)(i) of this section to adjust the NYMEX price for that oil between the market center and Cushing, Oklahoma. Otherwise, use paragraph (a)(3)(ii) to determine that adjustment. Use paragraph (b) or (c) of this section to value the oil that you do not transport or exchange to a market center.

(1) For oil that you transport between your lease and the market center (or between any intermediate points between those locations), you may take an allowance for the cost of transporting that oil between the relevant points as determined under § 206.110 or § 206.111, as applicable.

(2)(i) For oil that you exchange at arm's length between your lease and the market center (or between any intermediate points between those locations), you must adjust the NYMEX price by the applicable location and quality differentials derived from your arm's-length exchange agreement.

(ii) For oil that you exchange between your lease and the market center (or between any intermediate points between those locations) under an exchange agreement that is not at arm's length, you must obtain approval from MMS for a location and quality differential. Until you obtain such approval, you may use the location and quality differential derived from that exchange agreement. If MMS prescribes a different differential, you must apply MMS' differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS' differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(3)(i) For oil that you exchange at arm's length between the market center and Cushing, Oklahoma, you must adjust the NYMEX price by the applicable location and quality differentials derived from your arm's-length exchange agreement.

(ii)(A) For oil that you do not exchange at arm's length between the market center and Cushing, Oklahoma, you must use the WTI differential published in an MMS-approved publication for the market center nearest your lease, for crude oil most similar in quality to your production, as your location and quality differential between the market center and Cushing, Oklahoma. (For example, for sweet crude oil produced in the Rocky Mountain Region, use the WTI differential for Wyoming Sweet crude oil at Guernsey, Wyoming.)

(B) After you select an MMS-approved publication to calculate the WTI differential under paragraph (a)(3)(i) of this section, 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.

(4) You must determine the adjustments to the NYMEX price under paragraphs (a)(1) through (a)(3) of this section for each arrangement under which you dispose of production from your lease. For the oil disposed of under any one arrangement, you may not claim a transportation allowance between the same points between which you exchange that oil.

(5) *Example.* Assume that a Federal lessee produces crude oil from a lease near Artesia, New Mexico. Further assume that the lessee transports the oil to Roswell, New Mexico, and then exchanges the oil to Midland, Texas. Assume the lessee refines the oil received in exchange at Midland. Assume that the NYMEX price is $30.00/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is −$.10/bbl; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of −$.08/bbl; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is $.40/bbl. In this example, the royalty value of the oil is $30.00 − $.10 − $.08 − $.40 = $29.42/bbl.

(b) If you transport or exchange (or both transport and exchange) at least 20 percent, but not all, of your oil produced from the lease to a market center, determine the value of the portion of the oil produced from your lease that is valued using the NYMEX price under § 206.103 but that is not transported or exchanged (or both transported and exchanged) to or through a market center as follows:

(1) Determine the volume-weighted average of the adjusted NYMEX prices determined under paragraph (a) of this section for the oil that you do transport or exchange (or both transport and exchange) from your lease to a market center.

(2) Use that volume-weighted average NYMEX price as the value of the oil that you do not transport or exchange (or both transport and exchange) from your lease to a market center.

(3) *Example.* Assume the same facts as in the example in paragraph (a)(5) of this section, except that the lessee transports and exchanges to Midland 40 percent of the production from the lease near Artesia, and transports the remaining 60 percent directly to its own refinery in Ohio. In this example, the 40 percent of the production would be valued at $29.42/bbl, as explained in the previous example. Under this paragraph (b), the other 60 percent also would be valued at $29.42/bbl.

(c)(1) If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to MMS a differential between the lease and the market center for the portion of the oil that you do not transport or exchange (or both transport and exchange) to a market center. Use the WTI differential between the market center and Cushing, Oklahoma, to adjust the NYMEX price between those two points.

(2) You may use the differential you propose until MMS prescribes a different differential.

(3) If MMS prescribes a different differential, you must apply MMS'' differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS'' differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(d)(1) If you adjust for location and quality differentials or for transportation costs under paragraphs (a), (b), or (c) of this section, also adjust the NYMEX price for quality based on premia or penalties determined by pipeline quality bank specifications at intermediate commingling points or at the market center if those points are downstream of the royalty measurement point approved by MMS or BLM, as applicable. Make this adjustment only if and to the extent that such adjustments were not already included in the location and quality differentials determined from your arm's-length exchange agreements.

(2) If the quality of your oil as adjusted is still different from the quality of the representative crude oil at the market center after making the quality adjustments described in paragraphs (a), (b), (c), and (d)(1) of this section, you may make further gravity adjustments using posted price gravity tables. If quality bank adjustments do not incorporate or provide for adjustments for sulfur content, you may make sulfur adjustments, based on the quality of the representative crude oil at the market center, of 2.5 cents per one-tenth percent difference in sulfur content, unless MMS approves a higher adjustment.

10. Section 206.118 is deleted.

11. In § 206.119, the first sentence of paragraph (c) is removed.

12. Section 206.121, the section heading and the first sentence are revised to read as follows:

§ 206.121. Is there any grace period for reporting and paying royalties?

You may adjust royalties reported and paid for the three production months beginning June 1, 2000, without liability for late payment interest if those adjustments are reported before [THE DATE THAT IS 90 DAYS AFTER THE PUBLICATION OF THE FINAL RULE IN THE **Federal Register**].

* * * * *

PART 210—FORMS AND REPORTS

Subpart B—Oil, Gas, and Sulphur—General

13. The authority for part 210 is revised to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396, 396d, 2107; 30 U.S.C. 189, 190, 359, 1023, 1751(a); 31 U.S.C. 3716, 9701; 43 U.S.C. 1334, 1801 *et seq.*; and 44 U.S.C. 2506(a).

14. In § 210.53, a new paragraph (c) is added to read as follows:

§ 210.53. Reporting instructions.

* * * * *

(c) This paragraph applies if an operator under a joint operating agreement is also a designee and reports and pays royalty on behalf of one or more working interest owners from whom the operator buys production. On the Form MMS–2014, the operator must report the following information on separate lines:

(1) The share of the production the operator purchased from each working interest owner and the associated royalty payment; and

(2) The operator's own share of production and the associated royalty payment.

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DEPARTMENT OF DEFENSE

Department of the Army, Corps of Engineers

33 CFR Part 326

RIN 0710–AA54

Civil Monetary Penalty Inflation Adjustment Rule

AGENCY: U.S. Army Corps of Engineers, DoD.

ACTION: Proposed rule.

SUMMARY: The U.S. Army Corps of Engineers (Corps) is proposing to amend its regulations to adjust its Class I civil penalties under the Clean Water Act and the National Fishing Enhancement Act. The adjustment of civil penalties to account for inflation is required by the Federal Civil Penalties Inflation Adjustment Act of 1990, as amended. Since we have not made any adjustments to our Class I civil penalties to account for inflation since 1989, we are proposing to make the initial 10 percent increase under this Act. The proposed adjusted Class I civil penalty under the Clean Water Act will not exceed $11,000 per violation, with a maximum civil penalty amount of $27,500. Under the National Fishing Enhancement Act, the proposed adjusted Class I civil penalty will not exceed $11,000 per violation. Increasing the maximum amounts of the Class I civil penalties to account for inflation will maintain the deterrent effects of those penalties.

DATES: Submit comments on or before October 6, 2003.

ADDRESSES: You may submit comments electronically, by mail, or through hand delivery or courier. Send electronic comments via e-mail to *cecwor@usace.army.mil*. Electronic comments should be submitted in ASCII format, to ensure that those comments can be read. Please avoid the use of special characters or encryption when providing electronic comments. Mail comments to HQUSACE, ATTN: CECW–OR, 441 ''G'' Street, NW., Washington, DC 20314–1000.

FOR FURTHER INFORMATION CONTACT: Mr. David Olson at 202–761–4598 or access the U.S. Army Corps of Engineers Regulatory Home Page at *http://www.usace.army.mil/inet/functions/cw/cecwo/reg/*.

SUPPLEMENTARY INFORMATION:

Background

On December 8, 1989, (54 FR 50709) the Corps issued final regulations at 33 CFR 326.6 for procedures for the initiation and administration of Class I administrative penalty orders under section 309(g) of the Clean Water Act and section 205(e) of the National Fishing Enhancement Act. Under section 309(g) of the Clean Water Act, Class I civil penalties can be assessed for violations of the conditions and limitations of permits issued under section 404 of the Clean Water Act. Under section 205(e) of the National Fishing Enhancement Act, Class I civil penalties can be assessed for violations of permits issued section 10 of the Rivers and Harbors Act of 1899 and/or section 404 of the Clean Water Act for the construction and management of artificial reefs. Our current regulations at 33 CFR 326.6(a)(1) reflect the Class I civil penalty amounts stated in those statutes.

As stated in 33 CFR 326.6(a)(1), Class I civil penalties under section 309(g)(2)(A) of the Clean Water Act cannot exceed $10,000 per violation, with a maximum Class I civil penalty of $25,000. In that subsection, the Class I civil penalty for a violation of a permit issued in accordance with section 205 of the National Fishing Enhancement Act cannot exceed $10,000 for each violation.