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30 CFR Parts 202 and 206
Amendments to Gas Valuation Regulations for Indian Leases; Proposed Rule

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 202 and 206

RIN 1010–AB57

Amendments to Gas Valuation Regulations for Indian Leases

AGENCY: Minerals Management Service, Interior.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Minerals Management Service (MMS) is proposing to amend its regulations governing the valuation for royalty purposes of natural gas produced from Indian leases. These changes would add alternative valuation methods to the existing regulations. The proposed rule represents recommendations of the MMS Indian Gas Valuation Negotiated Rulemaking Committee (Committee). This proposed rule also contains two new MMS forms and solicits comments on these information collections.

DATES: Comments must be submitted on or before November 22, 1996.

ADDRESSES: Mail written comments, suggestions, or objections regarding the proposed rule to: Minerals Management Service, Royalty Management Program, Rules and Procedures Staff, P.O. Box 25165, MS 3101, Denver, Colorado, 80225–0165, courier address is: Building 85, Denver Federal Center, Denver, Colorado 80225, or e:Mail David__Guzy@smtp.mms.gov. MMS will publish a separate notice in the Federal Register indicating dates and locations of public hearings regarding this proposed rulemaking.

FOR FURTHER INFORMATION CONTACT: David S. Guzy, Chief, Rules and Procedures Staff, telephone (303) 231–3432, FAX (303) 231–3194, e:Mail David__Guzy@smtp.mms.gov, Minerals Management Service, Royalty Management Program, Rules and Procedures Staff, P.O. Box 25165, MS 3101, Denver, Colorado, 80225–0165.

SUPPLEMENTARY INFORMATION: The principal authors of this proposed rule are Donald T. Sant, Connie Bartram, and Greg Smith of the MMS, and Peter Schaumberg of the Office of the Solicitor. Members of the MMS Indian Gas Valuation Negotiated Rulemaking Committee also participated in the preparation of this proposed rule.

I. Introduction

On August 4, 1994, MMS published an Advance Notice of Proposed Rulemaking regarding the possible amendment of the valuation regulations for gas production from Indian leases (59 FR 39712). The stated intent of any amendments was to ensure that Indian mineral lessors received the maximum revenues from mineral resources on their land consistent with the Secretary of the Interior's (Secretary) trust responsibility and lease terms. It was also MMS's desire to improve the regulatory framework so that information was available which would permit lessees to comply with the regulatory requirements at the time that royalties were due.

On January 31, 1995, the Secretary chartered the Committee to develop specific recommendations with respect to the valuation of gas production from Indian leases (60 FR 7152, February 7, 1995). Members of the Committee included representatives of the Navajo Nation, the Jicarilla Apache Tribe, the Native American Rights Fund, the Shoshone and Arapaho Tribes of the Wind River Reservation, the Northern Ute Tribe, the Southern Ute Indian Tribe, the Ute Mountain Ute Tribe, the Council of Energy Resource Tribes, the Shii Shi Keyah Association, the Council of Petroleum Accountants Societies (COPAS), the Rocky Mountain Oil and Gas Association (RMOGA), the Independent Petroleum Association of Mountain States (IPAMS), a major producer, the Mid-continent Oil & Gas Association, the Bureau of Indian Affairs, and MMS.

There were 19 members on the Committee. The Committee agreed that a minimum of 14 people had to be in attendance to conduct the business of the Committee. The Committee also agreed that it was necessary to have a 2/3 vote of the members present in favor of a proposal to adopt the proposal as a Committee recommendation.

The policy of the Department of the Interior is, whenever practicable, to afford the public an opportunity to participate in the rulemaking process. All of the Committee sessions were announced in the Federal Register, were open to the public, and provided an opportunity for public input. In addition, any interested persons may submit written comments, suggestions, or objections regarding this proposed rule to the location identified in the ADDRESSES section of this preamble. As an aid to public participation in this rulemaking, comments received will be posted on the internet at http://www.rmp.mms.gov unless the submitter has requested confidentiality.

MMS commends the Committee's ability to compromise and develop a proposal that would simplify royalty payments on natural gas produced from Indian leases, provide lessees with the information to comply with the regulations at the time royalties are due, decrease administrative costs, decrease litigation costs, and provide the Indian lessors with the maximum revenue consistent with their lease terms.

II. General Description of the Proposed Rule

In August 1996, the Committee published its final report which summarizes the Committee's recommendations. This report forms the basis for many of the proposals in this rulemaking and is an essential part of the regulatory history for this proposed rulemaking. Contact the person listed in **FOR FURTHER INFORMATION CONTACT** section or use the Internet access (http://www.rmp.mms.gov) to obtain a copy of the report.

The proposed rulemaking would simplify and add certainty to the valuation of production from Indian leases. It provides a methodology to calculate the value of production for standard form Tribal and allottee Indian leases that provide for value to be based on factors including the highest price paid or offered for a major portion of gas (major portion) at the time royalty payments are due. Most valuation would be based on published index prices for gas production from leases on reservations. It would also provide an alternative methodology for dual accounting. Thus, the lessee could elect to simplify the calculations for the requirement to pay royalties on the greater of the combined value of the residue gas and gas plant products resulting from processing the gas, or the value of the gas prior to processing.

This proposed rule would eliminate the need to calculate specific transportation allowances in most cases. Also, processing allowance calculations for lessees choosing the alternative methodology for dual accounting would be eliminated.

The requirement to file transportation or processing allowance forms in anticipation of claiming an allowance would be eliminated. In cases where lessees still would claim an allowance, data to verify the allowance claimed would be submitted to MMS.

These proposed rules contain two new MMS forms: Form MMS–4410, Certification for Accounting for Comparison, and Form MMS–4411, Safety Net Report. These forms are attached to this notice of proposed rulemaking as appendix A and appendix B. Commenters are requested to provide comments on these forms according to the information under the ''Paperwork Reduction Act'' in part IV. Procedural Matters of this notice.

A description of the major regulatory changes proposed in this rulemaking is provided in the next section. MMS recently restructured 30 CFR part 206 to create separate subparts applicable only to Indian leases (61 FR 5448, February 12, 1996). This was necessary because MMS made changes to the valuation regulations applicable to Federal leases that do not apply to Indian leases. This proposed rule also restructures 30 CFR part 202 to have separate sections for Federal and Indian leases. Thus, all the Indian valuation rules and procedures would be contained in a new subpart J of 30 CFR part 202 and subpart E in 30 CFR part 206.

In situations where the new index-based or other alternative valuation methods would be inapplicable, MMS would retain much of the structure of the existing valuation rules in 30 CFR part 206. A few changes would be substantive. However, in an effort to clarify and simplify those rules, MMS would be incorporating many changes to those sections that are not substantive but are an effort to implement concepts of *plain English*.

Also, on July 31, 1996, (62 FR 39931) MMS published a proposed rulemaking to amend the transportation allowance regulations for Federal and Indian leases. That proposed rule would clarify which costs are deductible as transportation costs and which costs are not deductible because they are not costs of transportation. MMS will incorporate in this rule any changes as a result of that proposed rulemaking.

III. Description of the Regulatory Proposal

30 CFR Part 202

MMS proposes to amend part 202 to add a new subpart J as described below. Where necessary, MMS will change the references to the applicable subparts of 30 CFR part 206 as they pertain to Indian gas, and will rename subpart D in part 202 as Federal Gas.

Section 202.550 How to Determine the Royalty Due on Gas Production

MMS is adding paragraph names to highlight the information contents of proposed § 202.550. In paragraph (a), MMS proposes that a Tribe rather than MMS would decide when the lessor would take Indian gas royalty in-kind. This paragraph also contains a new provision stating that a lessee of an Indian lease who demonstrates economic hardship may request a royalty rate reduction which is subject to the approval of the Indian lessor and the Secretary. MMS specifically would like comment on whether the Department should provide approval for allotted leases rather than seeking approval of the many individual allottees who may share in a single lease.

Proposed § 202.550(b) would require that you pay royalties on your entitled share of gas production from Indian leases not in approved Federal agreements, a defined term. It provides that you may pay on your takes if you notify the Associate Director for Royalty Management in writing that all persons paying royalties on the lease also agree to pay on their takes. However, if you pay royalties on your takes that are less than your entitled share, you are still liable for the royalties on your entitled share if the person taking the production does not pay the royalties that are owed. For example, assume there are two lessees each owning 50 percent of an Indian lease, and the production for a month is 100 Mcf. If lessee A takes 25 Mcf, and lessee B takes 75 Mcf, lessee A pays royalties on 25 Mcf, but is still liable for royalties on 50 Mcf if for some reason lessee B does not pay royalties on the 75 Mcf it took.

In proposed § 202.550(c), MMS has organized the regulation into paragraphs (i) Royalty rate; (ii) Volume; and (iii) Value, to clarify the way gas produced within an approved Federal agreement (AFA—including units and communitization agreements) must be calculated, reported, and paid to MMS or the Tribe.

In proposed § 202.550(c), MMS proposes to retain the requirement that royalty is due on the full monthly share of production allocated to an Indian lease under the terms of the AFA at the royalty rate specified in the lease. However, MMS is adding clarification that royalty would be due on each lessee's (generally operating rights owner's) entitled share of production allocable to the lease.

If a lessee takes its entitled share of production, value would be determined under 30 CFR part 206 for the full volume. However, a lessee may take more or less than its entitled share in a month. MMS proposes that the value for royalty purposes of the entitled share of production when the lessee (operating rights owner) takes more than its entitled share of the AFA production would be the weighted average value of the production taken. The existing regulations require lessees to distribute ratably from the overtaken leases to the undertaken leases using the value of the overtaken volumes. The proposed weighted average value would ease the valuation work for lessees, MMS, and Indian lessors.

Also included in § 202.550(c) would be procedures to value the portion of any production which a lessee is entitled to but does not take. If a lessee takes a portion of its entitled volumes, the value of production would be the weighted average value of the production that lessee took for the lease in the AFA. If a lessee takes none of its entitled volume, the value of production would be the index- based value (discussed later in this preamble) for leases in a zone with a valid index (discussed at 30 CFR 206.172). In a zone without a valid index, the value of production would be the first applicable of several benchmarks. The first benchmark under 30 CFR part 206 would be the weighted- average value of the gas that the lessee took from other leases in the same AFA that month. The second benchmark under 30 CFR part 206 would be the weighted-average value of production the lessee took from other Indian leases in the same field or area that month. The third benchmark under 30 CFR part 206 would be the weighted-average value of production the lessee took from Indian leases in the same AFA the previous month. The fourth benchmark under 30 CFR part 206 would be the weighted-average value of production the lessee took from Indian leases in the same field or area the previous month. The fifth and last benchmark would be the latest major portion value MMS sent to the lessee (discussed at 30 CFR 206.174).

Section 202.551 Standards for Reporting and Paying Royalties on Gas

This section is basically unchanged from the current regulations at § 202.152.

30 CFR Part 206

MMS is proposing to amend subpart E applicable only to Indian gas valuation. Many of the provisions are the same as in the existing rules in substance, but would be rewritten for purposes of clarity.

Section 206.170 What This Subpart Applies To

This section would be renamed and is basically the same as the existing rules. A new paragraph (c) would be added to allow valuation methodologies other than those prescribed in the rules if the lessee, Tribal lessor, and MMS jointly agree to the methodology. For Indian allottee leases, only MMS and the lessee must agree.

Section 206.171 Definitions

MMS would retain most of the definitions in § 206.171. However, new definitions would be added and existing definitions revised to allow for the simplification of valuation methodologies. New definitions are proposed for: *active spot market, approved Federal agreement, dedicated, drip condensate, dual accounting, entitlement, facility measurement point, index, index pricing point, index zone, major portion, MMS, natural gas liquids, operating rights owner, takes,* and *zone.* These definitions will be discussed below where they appear in the text of the regulation.

The proposed rule would remove the definitions of *marketing affiliate* and *warranty contract* because they are no longer relevant to valuation in today's market. The definition of allowance would be revised to reflect the elimination of certain forms the existing regulations require.

Section 206.172 How To Value Gas Produced from Leases in an Index Zone

This section is proposed to be removed, and a new § 206.172 is proposed to be added. This section is the principal new provision of the proposed regulation. This proposal removes the existing text of § 206.172 and replaces it with new language explaining the new valuation principles in the rule. Where it is applicable, it would greatly simplify the gas valuation process. This section would determine the value of gas production using data available in national publications. Likewise, major portion calculations could be made from the information published monthly in various publications. It simplifies what has been a difficult royalty valuation calculation for MMS and one that lessees seldom could make. This new calculation also would provide increased revenue for Indian Tribes and allottees consistent with their lease terms.

This proposed § 206.172 establishes the rules for lessees to use an index-based valuation method to value gas production from leases in MMS-determined index zones. These index zones, defined in proposed § 206.171 as a geographic area containing blocks or fields that MMS will define, would reflect areas with active spot markets. An active spot market is defined in proposed § 206.171 as a market where one or more MMS-acceptable publications publish bidweek prices (or if bidweek prices are not available, first-of-the-month prices) for at least one index pricing point in the index zone. An index pricing point is defined in proposed § 206.171 as any point on a pipeline for which there is an index. An index zone could be a large area or a small area. For Jicarilla-Apache Reservation, Southern Ute Reservation and Navajo Nation Indian leases, one likely index zone would be the San Juan basin. This is because the publications who publish the index prices generally publish one index price for this entire area. Another likely index zone would be the *Rocky Mountain* zone, which would apply to the Uintah and Ouray Reservation and the Wind River Reservation.

Proposed paragraph (a) would provide that this index-based method applies to leases with a major portion provision, a defined term. In these leases, the Secretary may determine value based upon the highest price paid or offered for a major portion of gas production in the field. It also would apply to leases which do not have a major portion provision but provide for the Secretary to determine value. This section also would provide that this index-based value could not be used to value carbon dioxide, nitrogen, or other non-Btu components of the gas stream.

Proposed paragraph (b) explains how to value residue gas and gas prior to processing. This section also applies to gas that the lessee certifies to MMS that it is not processed before it flows into a pipeline with an index (i.e., a pipeline with published index prices) but which may in fact be processed downstream of that point. It also should be noted that this section applies to both arm's-length and non-arm's-length sales.

Under proposed paragraph (b)(2), the value of gas which is *not* sold under a dedicated contract (defined in 30 CFR 206.171), would be the index-based value calculated as described below. However, if that gas production was subject to a previous contract which was the subject of a gas contract settlement, the lessee would be required to compare the index-based value with the value determined under 30 CFR 206.174. That section basically applies the valuation procedures that have been in effect since 1988. Thus, for example, if the lessee's gross proceeds are higher, that would determine value. This was not a Committee recommendation, but is proposed by MMS to continue current policy. The issue of royalty on contract settlement proceeds is currently in litigation.

If the gas *is* sold under a dedicated contract, then the value is the higher of the index-based value, described below, or the value determined under 30 CFR 206.174.

This section of the proposed rule also makes the index-based method available to value processed gas. Under paragraph (c), if gas is processed before it flows into a pipeline with an index, value is the *higher* of:

- The index-based value, described below, or
- The value of the gas after processing, including the residue gas and all gas plant products.

The value of the gas after processing may be determined two ways. The first is to use the alternative method for dual accounting described below in § 206.173 (which applies a specified increment to the value of the unprocessed gas to reflect the increase in the value for processing). The second method is to determine the combined value of the residue gas (using either paragraph (b)(2) or (b)(3) of this section, described above), the gas plant products (using the applicable valuation procedures), and any drip condensate.

Paragraph (d) of proposed § 206.172 describes how to calculate the index-based value per MMBtu of production. This index-based value must be calculated separately for each zone where a lessee has production.

First, for each MMS-approved publication, the lessee must calculate the average (a simple arithmetic average) of the *highest* reported prices for all of the index pricing points in the index zone. This includes all index pricing points included in the publication even if the lessee does not sell any gas which flows through a particular index pricing point. As explained below, MMS may exclude certain index prices from the calculations. Next, these averages are summed and the total is divided by the number of publications. This average is then reduced by a factor of 10 percent, but not less than 10 cents or more than 30 cents per MMBtu. This reduction is intended to reflect an allowance for transportation. Therefore, when using this index-based method, no other transportation allowance will apply.

Proposed paragraph (d)(2) would provide that MMS will publish in the Federal Register the index zones that are eligible for the index-based valuation method. It also lists the criteria MMS will consider in determining eligible index zones. The criteria include common markets served and common pipeline systems. The published index prices within an index zone, therefore, should be similar.

One of the criteria in determining zone eligibility would be that MMS-approved publications establish index prices that accurately reflect the value of production in the field or area where the production occurs. This would allow MMS, in consultation with affected Tribes and industry, to consider whether a particular set of index prices properly reflect value near the production areas.

Proposed paragraph (d)(3) allows MMS to disqualify a zone if market conditions change. Before a zone is disqualified, MMS will hold a technical conference. MMS will publish any zone disqualifications in the Federal Register.

Proposed paragraph (d)(4) would provide that MMS publish the MMS-acceptable publications in the Federal Register. It also lists the criteria MMS will consider in determining acceptable publications. The criteria include that buyers and sellers frequently use the publications. Also, the publications must use adequate survey techniques, and they must be independent from MMS, lessors, and lessees.

Proposed paragraph (d)(5) would provide that publications could petition MMS to become an acceptable publication.

Proposed paragraph (d)(6) would allow MMS to exclude an individual index price for an index zone in a publication that MMS otherwise approves. This would allow exclusion of a particular index price that MMS may find to be anomalous without disqualifying the other index prices for other index zones in that publication.

Proposed paragraph (d)(7) would provide that MMS will specify which tables in the publications to use to determine the index-based value.

Proposed paragraph (d)(8) states that transportation or processing allowance deductions are not to be used if the index-based value is used to value gas production. As explained above, the index-based value has already been adjusted between 10 cents and 30 cents per MMBtu to reflect transportation. As explained below, the dual accounting provision of the rule would provide adjustments for processing gas.

To ensure that the index-based value represents market value, the proposed rule provides for two safeguards. The first safeguard would be situations where there are contracts that dedicate gas production from specific wells or leases to those sales contracts. The Committee was aware that certain sales contracts exist that are for higher prices than available under the current spot market. Thus, as explained above, under § 206.172(b)(3), for dedicated contracts the lessee would have to calculate its value under current principles (gross proceeds) in the regulations, less allowances, and compare that value to the index-based value. The lessee would pay royalties on the higher of the two values. The Committee agreed that the Indian lessor should receive the benefit from these higher price sales contracts. The Committee did not believe that this provision added complexity because most dedicated gas sales contracts were wellhead sales and all dedicated gas sales contracts were for gas sales before the index point. Lessees, therefore, would not have to trace gas sales beyond the index point.

The second safeguard is in proposed § 206.172(e) that provides for a minimum value for royalty purposes under this section, referred to as the safety net price. The published index prices reflect prices for gas sold in the spot market. The volume of gas being sold on the spot market currently is between 25–40 percent of total production. Therefore, to ensure that the index-based value represents the value of all market transactions, the Committee proposed a safety net to compare index prices to prices that reflect sales made beyond an index point. The safety net price would be calculated using prices received for gas sold downstream of the index point. It would include only the lessee's or its affiliates sales prices, and it would not require detailed calculations for the costs of transportation. This was a contentious issue with the industry representatives, as they object to tracing gas sales. They also believe that the index-based value is representative of market value.

By June 30 following each calendar year, the lessee would be required to calculate for each month of the calendar year a safety net price. This must be calculated for each index zone where the lessee has an Indian lease. The safety net price for each index zone would be the volume weighted average contract price per delivered MMBtu of gas sold under the lessee's arm's-length contracts for the disposition of gas from all of the lessee's leases in the same index zone (in this instance including the lessee's Federal, State and fee properties in addition to its Indian leases). However, the lessee would only include sales under those contracts that establish a delivery point beyond the first index pricing point to which the gas flows. Moreover, those contracts must include gas attributable to one or more of the lessee's Indian leases in the index zone. The safety net price would capture the significantly higher-values for sales occurring beyond the index point. The lessee would submit its safety net price to MMS annually (by June 30) using Form MMS–4411. For purposes of this subsection only, the contract price would not include any amounts the lessee received in compromise or settlement of a predecessor contract for that gas. The contract price also would not include any adjustments to that price for placing gas production in marketable condition or to market the gas, or for any amount related to marketable securities associated with the sales contract (e.g., NYMEX futures). Also, except as described below, no transportation allowance would be applicable.

The Committee recognizes that transportation adds value for sales beyond the index point. To adjust for this value, the lessee would reduce the safety net price by 20 percent before any comparison is made to the index-based value. Use of a percentage was selected to retain simplicity in these rules compared to requiring the calculation of the actual cost of transportation. The Committee agreed that the 20 percent figure was a reasonable approximation of transportation costs. This reduction for transportation is greater than the 10 percent reduction in § 206.172(d)(1) because the safety net prices relate to sales that occur further from the lease.

The amount that is 80 percent of the safety net price would be compared to the amount that is 125 percent of the monthly index value for the index zone. The use of 125 percent of the index value also recognizes that there can be value added services other than transportation after the index point. The lessee would owe additional royalties plus late-payment interest if 125 percent of the index value were less than 80 percent of the safety net price. To calculate the additional royalties owed, the lessee would multiply the safety net differential (the 80 percent figure minus the 125 percent figure) by the volume of the lessee's gas production from Indian leases in the index zone that is sold beyond the first index pricing point in the index zone through which the gas flowed. This is the gas production that was sold at the higher prices. The additional revenue would be allocated to each Indian lease in the index zone with production sold beyond the index pricing point. We call this safety net production. The additional revenue would be allocated by dividing the volume (in MMBtu's) of production from an Indian lease in the index zone by the total volume (in MMBtu's) of safety net production from all of the lessee's Indian leases and multiplied by the additional royalties owed. The Committee believed that index-based value was a good determinant of value for production sold before or at the index point, and any safety net price ought to apply only to the production that was sold at the higher prices.

The Committee had certainty as one of its goals. The proposed rule would give MMS 1 year from the date it receives the lessee's Form MMS–4411 providing the safety net price to order the lessee to amend its safety net price calculation. If MMS did not order any adjustment to the safety net price, the safety net price would be final for the lessee.

Section 206.173 Alternative Methodology for Dual Accounting (Accounting for Comparison)

This section would be removed and a new § 206.173 is proposed that would offer an option for lessees to meet the dual accounting requirement in Indian leases, applicable to processed gas, using a simple calculation. Dual accounting is required under most Indian leases whenever gas is processed.

Under the proposed rule, a lessee would have the option to use the traditional dual accounting method in proposed § 206.176. This method compares the value of the gas prior to processing to the value of the residue gas, gas plant products, and drip condensate. Each of these values would be determined using the various valuation provisions of the rules, as appropriate. Royalty is due on the higher of the two values.

However, the proposed rule in § 206.173(b) also would provide the simpler alternative methodology for dual accounting. Under this method, the lessee first would determine the pre-processing value of the gas production using either § 206.172 or § 206.174. Then, a prescribed increment would be applied to reflect the increased value of the production after processing. Thus, value would be determined using the following equation:

Post-processing value = (Value determined in § 206.172 or § 206.174) × (1 + Increase for Dual Accounting).

The proposed increments are specified in § 206.173. They were calculated using two different values for the processing allowance of one test plant. A processing allowance of 33 percent was used to represent a typical allowance for a lessee that does not own an interest in the processing plant. A processing allowance of 20 percent was used as a typical allowance for a lessee that has an ownership interest in the processing plant. The increments represent the average uplifts in the value of gas prior to processing over several years of the value of gas after processing based on gas Btu quality and allowance data for one plant.

The dual accounting increase in wellhead value therefore would be based on two factors: The Btu quality at the facility measurement point, and whether the lessee has an ownership interest in the processing plant. The increments range from 2.75 percent to 35.5 percent. The Btu quality for any lease would be the weighted-average Btu content of all the wells in the lease or agreement measured at the facility measurement points.

Therefore, under this alternative methodology, if any of the gas from the lease was processed and the weighted-average Btu quality per cubic foot was greater than 1,000 Btu per cubic foot (Btu/cf), the lessee simply could choose to increase the value for all the gas prior to processing by the dual accounting increment and pay royalties on that value. If the weighted-average Btu quality per cubic foot for a month on a lease were less than 1,000 Btu/cf and some or all of the gas were processed, the lessee would use the alternative methodology for the volumes of lease production from wells whose quality exceeds 1,000 Btu/cf. For wells on the lease whose quality is equal to or less than 1,000 Btu/cf, dual accounting is not required. In this case, the lessee would report the volumes and the weighted-average Btu quality for wells above 1,000 Btu/cf as a separate item on Form MMS–2014, and report another line item for the volume of gas and the weighted-average quality for wells with Btu quality below 1,000 Btu/cf.

Under proposed § 206.173(a), lessees would make an election between actual dual accounting and the alternative methodology. The election must be made separately for each MMS-designated area. The election would apply to all the lessee's leases in that designated area. It could happen that co-lessees of a lease would use different dual accounting methods for their representative volumes because they have made different elections for all their respective lease interests in the designated area. Also, even if two co-lessees elected to use the alternative methodology, the resulting valuation could be different if one co-lessee owned an interest in the processing plant and therefore was required to use a higher increment. The designated areas are limited to:

Alabama-Coushatta
Blackfeet Reservation
Crow Reservation
Fort Belknap Reservation
Fort Berthold Reservation
Fort Peck Reservation
Jicarilla Apache Reservation
MMS-designated groups of counties in the State of Oklahoma
Navajo Reservation
Northern Cheyenne Reservation
Rocky Boys Reservation
Southern Ute Reservation
Turtle Mountain Reservation
Uintah and Ouray Reservation
Ute Mountain Ute Reservation
Wind River Reservation
Any other area that MMS designates.

MMS also will publish in the Federal Register a list of all Indian leases that are in a designated area for purposes of these regulations.

A lessee could elect to begin using the alternative methodology at the beginning of any month. Once made, the election would remain in effect until the end of the following calendar year. Thereafter, the election to use the alternative methodology must remain in effect for two calendar years, unless the lessee receives permission to change from MMS and, for Tribal leases, the Tribal lessor.

If any new wells come into production, or if the lessee acquires new leases in the designated area, they too must be subject to the election to use the alternative methodology.

Section 206.174 How To Value Gas Production When an Index- Based Method Cannot Be Used

Section 206.174 would be removed, and a new § 206.174 is proposed. This new section would apply to the valuation of gas production that:

- Is from leases outside an index zone;
- Is sold under dedicated contracts;
- Is a gas plant product subject to the actual dual accounting method where the actual processing costs are used for the processing allowance; or
- Is a non-Btu component of the gas stream.

This section would consolidate the valuation principles previously included in existing §§ 206.172 and 206.173 for the valuation of processed and unprocessed gas primarily to eliminate redundant provisions. These are the rules that have been in effect since 1988. It would incorporate the gross proceeds valuation principles and combine them into one section because there is no need to separate the valuation of unprocessed gas from processed gas.

This section also provides that MMS would calculate a major portion value from values lessees initially submitted to MMS using these gross proceeds principles. To do this, lessees would report their current production month's value based on the valuation methodology of the current regulations depending upon whether it was an arm's-length or non-arm's-length transaction. Thus, for gas sold under an arm's-length contract, the lessee would report its gross proceeds less applicable allowances. For gas sold under a non-arm's-length contract, the lessee would report its value after following the benchmarks specified in the rule at § 206.174. Lessees would be required to report allowances as separate items on

Form MMS–2014. The lessee would report the value as either processed gas and associated natural gas liquids or unprocessed gas.

Within 90 days of the reporting month, MMS would calculate a major portion value, described below, using lessees' reported values for unprocessed gas and residue gas for leases on each designated area (the same designated areas as under § 206.173). MMS would send written notice to each lessee of the major portion value applicable to its leases depending upon where they are located.

The lessee would have 30 days to submit amended Forms MMS–2014 to MMS if the major portion was higher than the lessee's previously reported value. Lessees also would compute their dual accounting value using the major portion value as the wellhead value per MMBtu. They could make the dual accounting calculation using the alternative methodology or the actual dual accounting method using the major portion value as the value of the residue gas. However, late payment interest on any underpayment associated with a higher major portion value would not begin to accrue until the date the amended Form MMS–2014 is due to MMS. The Committee did not consider it equitable to assess interest for periods before MMS notifies the lessee of the major portion value.

For each designated area, MMS would calculate the major portion value by arraying all of the prices and volumes of the gas reported on Form MMS–2014 for leases in the designated area. Prices would be reduced first for any allowable transportation costs. The lowest price would be at the bottom and the highest price at the top. The major portion would be the value at which 25 percent of the gas was sold starting down from the highest price paid. This would be a change from the current regulation of calculating the major portion value as the value at which 50 percent plus 1 Mcf of gas was sold starting from the bottom.

The Committee had considerable deliberation on this issue. Indian lessors have criticized MMS since the publication of the definition of the major portion value in 1988. They have argued that the definition of the major portion in the 1988 regulation does not adequately represent the lease terms on the highest price paid or offered for a major portion of production. They argue that *median* is not synonymous with *major*. The Committee agreed that the price at which 25 percent or more of the gas is sold is a reasonable compromise on the term *major*.

The Committee agreed that the major portion value at the 25th percentile from the top was a reasonable safeguard for royalty payments in non-index areas. Therefore, the Committee recommended that the MMS-computed major portion value not be subject to unilateral change by MMS once MMS issues a written notice, building certainty into the lessee's royalty valuation. That provision is in § 206.174(a)(4)(ii). A lessee or an Indian lessor could appeal the major portion value if they could demonstrate that MMS had not performed the calculation correctly.

The Committee discussed having a minimum value for gas plant products when the alternative methodology for dual accounting is not used to value the production and the lessee chooses to use the actual dual accounting methodology. The Committee did not agree on this issue, but voted to include in the proposed rule a minimum value based on some concepts MMS used previously in a procedure paper on natural gas liquid products valuation.

The proposal is included at § 206.174(g)(2). It specifies that for each gas plant product, the value cannot be less than the monthly average minimum price reported in commercial price bulletins less a specified estimate of the cost of transportation and fractionation. The average minimum price for production from leases in Colorado in the San Juan Basin, New Mexico, and Texas would be prices reported for gas plant products at Mont Belvieu less 8.0 cents for transportation and fractionation. The average minimum price for production from leases in Arizona, in Colorado outside the San Juan Basin, Minnesota, Montana, North Dakota, Oklahoma, South Dakota, Utah, and Wyoming would be prices reported for gas plant products at Conway less 7.0 cents for transportation and fractionation.

We selected Mont Belvieu and Conway and divided the States among these two market centers based on our judgment of where production from these areas are transported for further fractionation and refining. The 8.0 cents per gallon for Mont Belvieu and the 7.0 cents per gallon for Conway are the best estimate of the cost of transportation from the areas plus the cost of fractionation. These estimates are not based on a detailed survey.

A commercial price bulletin is a bulletin such as ''Platt's Oilgram Price Report'' or the ''Bloomberg Report.'' The proposed rule would permit a lessee to use any price bulletin, but the lessee must use the same bulletin for all of a calendar year. The proposed rule would allow a substitute price bulletin if the bulletin a lessee was using ceased publication. The substitute bulletin would then be used for the rest of the calendar year.

If a lessee uses a commercial price bulletin that is published monthly, the monthly average minimum price is the minimum price reported by the bulletin. If a lessee uses a commercial price bulletin that is published weekly, the monthly average minimum price is the arithmetic average of the weekly minimum prices reported by the bulletin. If a lessee uses a commercial price bulletin that is published daily, the monthly average minimum price is the arithmetic average of the minimum prices reported by the bulletin for each Wednesday of the month.

MMS specifically requests comments on this proposal. Comments should address the following issues:

- Is a minimum value needed when a lessee chooses the actual dual accounting methodology?
- Are there other better methods to use?
- Are Conway and Mont Belvieu the proper locations to look for prices for gas plant products?
- Are the 7.0 and 8.0 cents per gallon the right deductions for transportation and fractionation?
- Would a percentage of the price or actual rates paid be a better deduction?

The remaining provisions of proposed § 206.174 are essentially the same as the existing rules except that the two duplicative sections applicable to unprocessed gas and processed gas would be consolidated into one section.

The Committee also believed that verification of value in certain areas without an index should be accomplished in a shorter period of time. The proposed rule includes a new provision in § 206.174(l) that for leases in Montana and North Dakota, lessees must make adjustments sooner, and MMS must complete its audits sooner than either has done historically. The rule would be limited to Indian leases in these two States because at this time there are no acceptable published indexes applicable to that area.

Therefore, under this section, if value is determined without deduction of a transportation or processing allowance, or if the allowance is determined under an arm's- length contract, a lessee must make all adjustments to value within 13 months of the production month. MMS must conclude any audit and order any adjustments to royalty value within 12 months after the adjustment reporting date. MMS has been defined to include Tribal auditors where appropriate acting under agreements pursuant to the Federal Oil and Gas Royalty

Management Act or other applicable agreements. As explained below, there are circumstances where these dates would be extended.

For royalty value which is determined using a non-arm's-length transportation or processing allowance, all adjustments must be made within 9 months of the submittal of the actual cost allowance report to MMS. MMS must conclude any audit and order any adjustments to royalty value within 12 months after the adjustment reporting date. If the lessee has both allowances, the period runs from the date MMS receives the later of the two reports.

The proposed rule provides exceptions to the time limit on completing audits and issuing orders. These exceptions are:

- When disputes exist between lessees and purchasers, transporters or processors, the time period for the lessee to make adjustments would extend until 6 months after resolution of the dispute. The period to audit and issue demands would be correspondingly extended;
- When the lessee and MMS agree to extend the time;
- When there is a pending regulatory proceeding by any agency with jurisdiction over gas sales prices (e.g., the Federal Energy Regulatory Commission or a State public utility commission), the time period for the lessee to make adjustments is extended for 90 days after that proceeding concludes (including judicial review). The period to audit and issue demands would be correspondingly extended;
- When the lessee fails or refuses to provide records or information necessary to complete the audit, the time period to issue demands or orders will be extended for any time periods that MMS cannot obtain the information. Thus, if MMS is required to issue a subpoena and it takes 2 years of judicial proceedings to enforce the subpoena, the time period to issue demands or orders would be extended until 12 months after those proceedings conclude;
- When the lessee intentionally misrepresents or conceals a material fact for the purpose of avoiding royalties, the time period to complete audits or issue demands, or orders would not be applicable.

This proposed section also would expressly provide that if a lessee becomes aware of an underpayment during the time period that adjustments may be made, it is required to report that adjustment. During an audit, if it is determined that the lessee made overpayments, the lessee may credit the overpayments for a lease against any underpayments on that same lease only discovered during the audit.

The proposed rule also would limit the time period for which MMS could issue a demand or order. Proposed paragraph (l)(3) would define *demand* or *order* to include restructured accounting orders that are based on repeated, systemic errors for a significant number of leases or a single lease for a significant number of reporting months. The restructured accounting order must specify the reason and factual basis for the order.

Section 206.175 How To Determine Quantities and Qualities of Production for Computing Royalties

This section would be removed, and a new § 206.175 would be proposed and would retain some of the existing regulations and also include some new provisions. The proposal revises existing language in this section to reflect new provisions for computing royalties. The Committee agreed to add Btu quality information to Form MMS–3160, Monthly Report of Operations, for each well. With this additional information, the Indian lessors and MMS could verify if the dual accounting alternative increment method was calculated correctly.

Valuation rules for production from Indian leases always have provided that a lessee must pay royalty for residue gas and gas plant products based on its share of the monthly net output of the plant. The problem was that lessees could not do this if they did not have access to plant data. Therefore, under the proposed rule, if a lessee has no ownership interest in the plant and does not operate the plant, it may use its contract volume allocation to determine its share of output. However, if the lessee has an ownership interest in the plant or if it operates the plant, then it must use calculated volumes as in the existing rules.

Section 206.176 How To Do Accounting for Comparison

This section would be removed, and a new § 206.176 is proposed to clarify when lessees must perform accounting for comparison under the proposed valuation methods and procedures in this subpart E. In summary:

- Accounting for comparison is required when gas is processed;
- When accounting for comparison is required, the lessee may use either actual dual accounting as described earlier in this preamble or the alternative valuation method described in § 206.173;
- If any gas flowing through a facility measurement point is processed, then all gas flowing through the facility measurement point is considered processed except as discussed below.
- To avoid accounting for comparison, a lessee must certify the gas was never processed prior to entering the pipeline with an index located in an index zone on Form MMS–4410.

Generally, if any gas production for a month is subject to dual accounting, that value sets the minimum value for all lease production that month. However, if any gas production from a lease for a month is processed, but the weighted average Btu quality is less than 1,000 Btu/cf, a different calculation is required. The proposed rule provides that the alternative method for dual accounting can be applied only to the volumes of gas production measured at the facility measurement point that exceeds 1,000 Btu/cf. Also, no dual accounting is required for the volumes of gas production measured at the facility measurement point which is less than 1,000 Btu/cf. This is discussed earlier in the preamble section discussing § 206.173.

Section 206.177 General Provisions Regarding Transportation Allowances

This section would be removed, and a new § 206.177 is proposed to recognize that while transportation allowances are not relevant to the proposed index-based valuation method at § 206.172, they are relevant to valuation in the following gas production situations at § 206.174:

- For leases not in an index zone;
- When gas is dedicated from a specific well or lease to a sales contract; and
- Non-Btu components of the gas stream.

For these situations, when a lessee values gas at a point distant from the lease, this section would authorize a transportation allowance for the reasonable actual costs of transporting gas to that distant point. The transportation allowance would be applicable to unprocessed gas, residue gas, and gas plant products. The lessee would be subject to the existing 50-percent limitation of the proceeds at the point distant from the lease. The proposed rule states that a lessee may not deduct any allowance for gathering costs, a defined term.

The other general transportation allowance provisions would remain the same.

Section 206.178 How To Determine a Transportation Allowance

This section would be removed, and a new § 206.178 is proposed to continue to differentiate between arm's-length and non-arm's-length transportation contracts.

In § 206.178(a)(1)(i), for arm's-length transportation contracts, the proposed section would remove the requirement for a lessee to pre-file Form MMS–4295, Gas Transportation Allowance Report, before deducting a transportation allowance. In its place, the lessee would be required to submit to MMS a copy of any transportation contract, including amendments, the lessee used as a basis for the reported allowance. Those documents, to the extent not previously provided, are due to MMS within 2 months of when the lessee reported the transportation deduction on Form MMS–2014.

The Committee believes this change will ease the burden on industry and still provide MMS with documents useful to verify the allowance claimed. Written contracts will not necessarily be required. For example, in a situation where the sale is to a mainline pipeline and there is no contract, the lessee would submit to MMS the copy of the invoice it received from the mainline pipeline company to support its transportation costs.

In the new § 206.178(b)(1) for non-arm's-length transportation or no contract situations, MMS would remove the requirement that a lessee submit a completed Form MMS–4295 before deducting a transportation allowance on Form MMS–2014. Rather, MMS would require the lessee to submit its actual cost information (supporting its allowance taken) within 3 months after the end of the calendar year period (or other MMS-approved period) for which the allowance pertains. MMS may approve a longer time period and would continue to ensure that deductions are reasonable and allowable.

To further simplify the royalty valuation calculation, the Committee recommended to allow a lessee to use a simple percentage calculation of the proceeds in situations where the transportation was non-arm's-length. Therefore, under § 206.178(c), the authorized allowance would be a fixed 10 percent of the gross value (not to exceed 30 cents per MMBtu) at the sales point. The percentage method would be available to a lessee only if the transportation was provided at least in part through a lessee-owned transportation system.

The lessee would have to elect to use either the transportation allowance percentage or actual cost method for 1 year. The election would apply to all of the lessee's leases in a designated area. The lessee may elect to begin using the percentage method at the beginning of any month. The first election to use the percentage method would be effective from the time of election through the end of the following calendar year.

The Committee agreed to permit a percentage of proceeds to determine a transportation allowance to simplify the gas valuation regulations and to ease administration for lessees, lessors, and MMS. The Committee agreed to using 10 percent mainly to match the percentage it derived in the index-based value. However, to ensure the percentage reflects other similar allowances, MMS would have to periodically review the validity of the percentage. In addition, MMS's disqualification of an index zone would automatically require MMS to review and determine if a new percentage better reflects current transportation rates. Until such time as a new percentage had been established, the lessee would be allowed to use either actual costs of transportation or 10 percent of the gross value at the sales point.

From the existing § 206.177(c), *Reporting requirements,* MMS would retain only the requirement that the lessee must report transportation allowance deductions as a separate item on Form MMS–2014, unless MMS approves a different reporting procedure and must submit all information to MMS to support Form MMS–4295 at the request of MMS. All other provisions regarding allowance filings would be removed.

Section 206.179 General Provisions Regarding Processing Allowances

MMS would remove this section and propose a new § 206.179 and § 206.180 below.

The extraordinary cost allowance would be eliminated. MMS believes at this time that it would be a better exercise of the Secretary's trust responsibility to not allow extraordinary cost allowance for Indian leases. We also would not allow any allowance in excess of two-thirds of the value of the marketable product. This was not a Committee proposal.

Section 206.180 How to Determine an Actual Processing Allowance

Section 206.180 would be added. MMS would not require that a lessee file Form MMS–4109, Gas Processing Allowance Summary Report, on arm's-length processing contracts.

MMS proposes that in place of these forms, MMS would continue to require that a lessee submit arm's-length processing contracts, agreements, and related documents within 2 months of reporting an allowance deduction on Form MMS–2014.

MMS would remove the requirement for the lessee to submit a completed Form MMS–4109 before deducting its non-arm's-length processing costs on Form MMS–2014. Proposed § 206.180(b)(3) would provide that processing allowances under paragraph (b) must be determined based on a calendar year or other MMS-approved period.

The proposed rule would retain the requirement that upon MMS's request the lessee must submit all data it used to determine its processing allowance, and that processing allowances be reported as a separate item on Form MMS–2014, unless MMS approves a different reporting procedure.

MMS would not require pre-approval or pre-filing of processing allowances, but would retain interest assessments for any underpayment of royalties caused when a lessee erroneously deducted a processing allowance.

Section 206.181 Processing Allowances for Use in Certain Dual Accounting Situations

MMS would add this proposed new section to address how to apply processing allowances in cases where the lease requires dual accounting but the gas is not processed by or on behalf of the lessee. The proposed section provides four benchmarks the lessee would follow in these situations.

IV. Procedural Matters

The Regulatory Flexibility Act

The Department certifies that this rule will not have significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). This proposed rule will amend regulations governing the valuation for royalty purposes of natural gas produced from Indian leases. These changes would add several alternative valuation methods to the existing regulations. Small entities are encouraged to comment on this proposed rule.

Unfunded Mandates Reform Act of 1995

The Department of the Interior has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on local, Tribal, State governments, or the private sector.

Executive Order 12630

The Department certifies that the rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, a Takings Implication Assessment need not be prepared under

Executive Order 12630, Government Action and Interference with Constitutionally Protected Property Rights.

Executive Order 12988

The Department has certified to the Office of Management and Budget that this proposed rule meets the applicable civil justice reform standards provided in sections 3(a) and 3(b)(2) of Executive Order 12988.

Executive Order 12866

This document has been reviewed under Executive Order 12866 and is not a significant regulatory action requiring Office of Management and Budget review.

Paperwork Reduction Act

This proposed rule contains two collections of information which have been 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, MMS invites the public and other Federal agencies to comment on any aspect of the reporting burden. Submit your comments to the Office of Information and Regulatory Affairs, OMB, Attention Desk Officer for the Department of the Interior, Washington, DC 20503. Send copies of your comments to: Minerals Management Service, Royalty Management Program, Rules and Procedures Staff, PO Box 25165, MS 3101, Denver, Colorado, 80225–0165; courier address is: Building 85, Denver Federal Center, Denver, Colorado 80225; e:Mail address is: David__Guzy@smtp.mms.gov.

One collection of information is titled ''Certification for Not Performing Accounting for Comparison (Dual Accounting).'' Accounting for comparison (dual accounting) is required by the terms of most Indian leases when gas produced from the lease is processed. To avoid dual accounting, a lessee must certify, using proposed Form MMS–4410 (Attachment 1), that the gas was never processed prior to entering the pipeline with an index located in an index zone. The lessee will be required to sign the certification form for each property having production that is exempt from dual accounting. This is a one time certification that will remain in effect until there is a change in lease status or ownership. This requirement will assist the Indian lessor in receiving all the royalties that are due and aid MMS in its compliance efforts.

Rules establishing the use of Form MMS–4410 to certify that gas production is not processed before it flows into a pipeline with an index but which may be processed later are at proposed 30 CFR 206.172(b)(1)(ii). The lessee or operator of an Indian lease will certify to MMS that gas produced from the lease specified on the form is not processed before entering a pipeline with an index located in an index zone. This certification will allow MMS and the tribes to better monitor compliance with the dual accounting requirement of Indian leases.

In most cases, the lessee or operator will directly know the disposition of the gas. If gas is sold at the wellhead, the lessee or operator may have to consult with the purchaser of the gas to find its disposition. Information provided on the forms may be used by MMS auditors, Valuation and Standards Division (VSD), and the Office of Indian Royalty Assistance.

MMS estimates the annual reporting burden to be approximately 5,412 hours. There are approximately 4,511 tribal and allotted Indian leases and 935 payors comprising the Indian lease universe. The MMS subject matter experts estimate that at most 30 percent of the Indian leases (1,353 leases) would not require accounting for comparison and would submit the certification forms. This one time filing as required by 30 CFR 206.172 (b)(1)(ii) could require about 3 hours per report to extract the data from company records or obtain the information from the purchaser. The certification will remain in effect until there is a change in lease status or ownership. Only a minimal recordkeeping burden would be imposed by this collection of information. Based upon $25 per hour, one time cost to industry is estimated to be $135,300.

The other collection of information contained in this proposed rule is titled ''Safety Net Report.'' The safety net calculation establishes the minimum value for royalty purposes. This requirement will assist the Indian lessor in receiving all the royalties that are due and aid MMS in its compliance efforts. The safety net price would be calculated using prices received for gas sold downstream of the index point. It would include only the lessee's sales prices, and it would not require detailed calculations for the costs of transportation. By June 30 following each calendar year, the lessee would be required to calculate for each month of the calendar year a safety net price. This must be calculated for each index zone where the lessee has an Indian lease. The safety net price would capture the significantly higher-values for sales occurring beyond the index point. The lessee would submit its safety net price to MMS annually (by June 30) using Form MMS–4411 (Attachment 2).

Rules establishing the use of Form MMS–4411 to report the safety net price are at proposed 30 CFR 206.172(e). The lessee would compare the amount that is 80 percent of the safety net price to the amount that is 125 percent of the monthly index value for the index zone. The lessee would owe additional royalties plus late-payment interest if 125 percent of the index value were less than 80 percent of the safety net price. The MMS would have 1 year from the date it receives the lessee's Form MMS–4411 providing the safety net price to order the lessee to amend its safety net price calculation. If MMS did not order any adjustment to the safety net price, the safety net price would be final for the lessee. This report will allow MMS and the tribes to ensure that Indian mineral lessors receive the maximum revenues from mineral resources on their land consistent with the Secretary's trust responsibility and lease terms.

The lessee or operator will directly know the disposition of the gas and the safety net price would include only the lessee's sales prices. The lessee would only include sales under those contracts that establish a delivery point beyond the first index pricing point to which the gas flows. Moreover, those contracts must include gas attributable to one or more of the lessee's Indian leases in the index zone. Information provided on the forms may be used by MMS auditors, Valuation and Standards Division (VSD), and the Office of Indian Royalty Assistance.

MMS estimates the annual reporting burden to be approximately 37,400 hours. About 935 companies pay royalties on approximately 4,511 tribal and allotted Indian leases. MMS subject matter experts estimate that about 24 hours are required per report to extract from company records the data required at proposed 30 CFR 206.172 (e). They also estimate that about 20 percent of the companies have sales beyond the first index pricing point. Therefore, reports from about 187 companies (.20 × 935) for 8 index zones are required annually. Only a minimal recordkeeping burden would be imposed annually by this collection of information. Based upon $25 per hour, annual costs to industry is estimated to be $935,000.

In compliance with the requirement of section 3506 (c)(2)(A) of the Paperwork Reduction Act of 1995, MMS is providing notice and otherwise consulting with members of the public and affected agencies concerning collection of information in order to solicit comment to: (a) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) enhance the quality, utility, and clarity of the information to be collected; and (d) minimize the burden of the collection of information on those who are to respond, including through the use of automated collection techniques or other forms of information technology.

The Paperwork Reduction Act of 1995 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.

National Environmental Policy Act of 1969

We have determined that this rulemaking is not a major Federal action significantly affecting the quality of the human environment, and a detailed statement under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. § 4332(2)(C)) is not required.

List of Subjects in 30 CFR Parts 202 and 206

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

Dated: September 6, 1996.

Bob Armstrong,

Assistant Secretary—Land and Minerals Management.

For the reasons set out in the preamble, Parts 202 and 206 of Title 30 of the Code of Federal Regulations are proposed to be amended as follows:

PART 202—ROYALTIES

1. The authority citation for Part 202 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, 1801 *et seq.*

2. The heading for Subpart D—Federal and Indian Gas—is revised to read as follows:

Subpart D—Federal Gas

3. Section 202.51(b) is revised to read as follows:

* * * * *

(b) The definitions in subparts C, D, E, and I of part 206 of this title are applicable to subparts B, C, D, I, and J of this part.

4. Sections 202.150 (b)(1), (e)(1), and (e)(2) are amended by removing the words ''or Indian''.

5. Section 202.150 paragraph (f) introductory text is amended by removing the words ''and Indian,'' and paragraph (f)(3) by removing the words ''or Indian.''

6. Section 202.151(a)(2) is amended by removing the words ''and Indian.''

7. A new subpart J is added to read as follows:

Subpart J—Gas Production From Indian Leases

Sec.

202.550 How to determine the royalty due on gas production.

202.551 Standards for reporting and paying royalties on gas.

Subpart J—Gas Production From Indian Leases

§ 202.550 How to determine the royalty due on gas production.

This section explains how lessees and other royalty payors must determine and pay royalties on gas production from Indian leases subject to this subpart.

(a) *Royalty rate.* (1) You must calculate royalties due on gas production from Indian leases using the royalty rate in the lease. You must pay royalty in value unless the Tribal lessor, or the Secretary of the Department of the Interior (Secretary) for allottee leases, requires payment in kind. When paid in value, the royalty due is the value, for royalty purposes, determined under 30 CFR part 206 multiplied by the royalty rate in the lease.

(2) If you demonstrate economic hardship, you may request a royalty rate reduction which is subject to the approval of the Indian lessor and the Secretary.

(b) *Leases not in an approved Federal agreement (AFA).* You must pay royalty on your entitled share of gas production from your Indian lease, except as provided in paragraphs (d), (e), and (f) of this section. You may pay on your takes if you notify the Associate Director for Royalty Management in writing that all other persons paying royalties on the lease also agree to pay on their takes. If you pay royalties based on your takes that are less than your entitled share, you are still liable for the royalties on your entitled share if the person taking the production does not pay the royalties owed.

(c) *Leases in an approved Federal agreement (AFA).* (1) You must pay royalties on production allocated to your lease under the terms of an AFA in accordance with the following requirements:

(i) *Royalty rate*—You must pay royalties based on the royalty rate specified in the lease. The lessee and the Indian lessor may agree to amend the royalty rate in the lease with the Secretary's approval.

(ii) *Volume*—You must pay royalties each month on your entitled share of production allocated to your lease under the terms of an AFA. This may include production from more than one AFA.

(iii) *Value*—The value of production that you take must be determined under 30 CFR part 206. If you take more than your entitled share of production for any month, the value of your entitled share is the weighted-average value of the production, determined under 30 CFR part 206, that you take during that month.

(iv) The value of production that you are entitled to but do not take for any month must be determined as follows:

(A) Where you take only a portion of your entitled share of production from a lease in an AFA, value for the undertaken volumes must be based on the weighted average of the value of the production you do take for that month from the same lease in the same AFA as determined under 30 CFR part 206. You may apply this valuation method only if you take a significant volume of production. If you do not take a significant volume of production from your lease for a month, you must use paragraph (c)(1)(iv)(B) or (C)(*1*)–(*5*) of this section whichever is applicable.

(B) If you take none of your entitled share of production in an AFA and that production would have been valued using an index-based method under § 206.172(b) of this title had it been taken, then you must determine the value of production not taken for that month under § 206.172(b) of this title as if you had taken it.

(C) If you take none of your entitled share of production from a lease in an AFA and that production cannot be valued under § 202.550(c)(1)(iv)(B), then you must determine the value of production not taken for that month based on the first applicable method as follows:

(*1*) The weighted average of the value of your production (under 30 CFR Part 206) from other leases in the same AFA that month;

(*2*) The weighted average of the value of your production (under 30 CFR Part 206) from other leases in the same field or area that month;

(*3*) The weighted average of the value of your production (under 30 CFR Part 206) during the previous month for production from leases in the same AFA that month;

(*4*) The weighted average of the value of your production (under 30 CFR Part 206) during the previous month for production from other leases in the same field or area; or

(*5*) The latest major portion value you received from MMS calculated under 30 CFR 206.174 for the same MMS-designated area.

(2) If you take less than your entitled share of AFA production for any month, but you pay royalties on the full volume of your entitled share in accordance with the provisions of this section, you will owe no additional royalty for that lease for that month when you later take more than your entitled share to balance your account. This also applies when the other AFA participants pay you money to balance your account.

(d) *Gas subject to royalty.* (1) All gas produced from or allocated to your Indian lease is subject to royalty except:

(i) Gas that is unavoidably lost;

(ii) Gas that is used on, or for the benefit of, the lease;

(iii) Gas that is used off-lease for the benefit of the lease when the Bureau of Land Management (BLM) approves such off-lease use; and

(iv) Gas used as plant fuel as provided in 30 CFR 206.179(e).

(2) You may use royalty-free only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility when you use gas:

(i) On, or for the benefit of, the lease at a production facility handling production from more than one lease with BLM's approval; or

(ii) At a production facility handling unitized or communitized production.

(3) If the terms of your lease are inconsistent with this subpart, your lease terms will govern to the extent of that inconsistency.

(e) *Avoidably lost, wasted, or drained gas and compensatory royalty.* If BLM determines that a volume of gas was avoidably lost or wasted, or a volume of gas was drained from your Indian lease for which compensatory royalty is due, then you must determine the value of that volume of gas in accordance with 30 CFR part 206.

(f) *Insurance compensation.* If you receive insurance compensation for unavoidably lost gas, you must pay royalties on the amount of that compensation. This paragraph does not apply to compensation through self-insurance.

(v) Reporting and payment—You must report and pay royalties as provided in part 218 of this title.

§ 202.551 Standards for reporting and paying royalties on gas.

This section provides technical standards for reporting and paying royalties on gas produced from Indian leases.

(a)(1) You must determine gas volumes and Btu heating values, if applicable, under the same degree of water saturation. You must report gas volumes in units of one thousand cubic feet (Mcf), and Btu heating value must be reported at a rate of Btu's per cubic foot, at a standard pressure base of 14.73 pounds per square inch absolute (psia) and a standard temperature base of 60°F. You must report gas volumes and Btu heating values, for royalty purposes, on the same water vapor saturated or unsaturated basis that the Federal Energy Regulatory Commission (FERC) prescribes in its regulations. You may use the basis prescribed in your gas sales contract as long as the sales contract does not conflict with FERC's regulations.

(2) You must use the frequency and method of Btu measurement stated in your contract to determine Btu heating values for reporting purposes. However, you must measure the Btu value at least semi-annually by recognized standard industry testing methods even if your contract provides for less frequent measurement.

(b) Residue gas and gas plant product volumes must be reported as follows:

(1) You must report carbon dioxide (CO_2), nitrogen (N_2), helium (He), residue gas, and any gas marketed as a separate product by using the same standards specified in paragraph (a) of this section.

(2) You must report natural gas liquid (NGL) volumes in standard U.S. gallons (231 cubic inches) at 60°F.

(3) You must report sulfur (S) volumes in long tons (2,240 pounds).

PART 206—PRODUCT VALUATION

8. The authority citation for Part 206 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701.; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

9. Subpart E of part 206 is revised to read as follows:

Subpart E—Indian Gas

Sec.

Subpart E—Indian Gas

§ 206.170 What this subpart applies to.

This subpart provides royalty valuation provisions applicable to Indian lessees.

(a) This subpart applies to all gas production from Indian (Tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation). The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms. This subpart does not apply to Federal leases.

(b) If the specific provisions of any Federal statute, treaty, negotiated agreement, settlement agreement resulting from any administrative or judicial proceeding, or Indian oil and gas lease are inconsistent with any regulation in this subpart, then the Federal statute, treaty, negotiated agreement, settlement agreement, or lease will govern to the extent of that inconsistency.

(c) You may calculate the value of production for royalty purposes under methods other than those the regulations in this title require, but only if you, the tribal lessor, and MMS jointly agree to the valuation methodology. For leases that Indian allottees own, you and MMS must agree to the valuation methodology.

(d) All royalty payments you make to MMS are subject to monitoring, review, audit, and adjustment.

(e) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian oil and gas leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

§ 206.171 Definitions.

The following definitions apply to this subpart and to subpart J of part 202 of this title:

Accounting for comparison means the same as dual accounting.

Active spot market means a market where one or more MMS-acceptable publications publish bidweek prices (or if bidweek prices are not available, first of the month prices) for at least one index pricing point in the index zone.

Allowance means a deduction in determining value for royalty purposes. Processing allowance means an allowance for the reasonable actual costs of processing gas determined under this subpart. Transportation allowance means an allowance for the reasonable actual cost of transportation determined under this subpart.

Approved Federal agreement (*AFA*) means a unit or communitization agreement approved under Department of the Interior (DOI) regulations.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and/or legal characteristics. An area may encompass all lands within the boundaries of an Indian reservation.

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(1) Ownership in excess of 50 percent constitutes control;

(2) Ownership of 10 through 50 percent creates a presumption of control;

(3) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify the percentage of ownership or control of the entity. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other persons who pay royalties, rents, or bonuses on Indian leases.

BIA means the Bureau of Indian Affairs of the Department of the Interior.

BLM means the Bureau of Land Management of the Department of the Interior.

Compression means raising the pressure of gas.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Dedicated means a contractual commitment to deliver gas production (or a specified portion of production) from a lease or well when that production is specified in a sales contract *and* that production must be sold pursuant to that contract to the extent that production occurs from that lease or well.

Drip condensate means any condensate recovered downstream of the facility measurement point without resorting to processing. Drip condensate includes condensate recovered as a result of its becoming a liquid during the transportation of the gas removed from the lease or recovered at the inlet of a gas processing plant by mechanical means, often referred to as scrubber condensate.

Dual Accounting (or *accounting for comparison*) refers to the requirement to pay royalty based on a value which is the higher of the value of gas prior to processing less any applicable allowances as compared to the combined value of drip condensate, residue gas, and gas plant products after processing, less applicable allowances.

Entitlement (or *entitled share*) means the gas production from a lease, or allocable to lease acreage under the terms of an AFA multiplied by the operating rights owner's percentage of interest ownership in the lease or the acreage.

Facility measurement point (or *point of royalty settlement*) means the point where the BLM-approved measurement device is located for determining the volume of gas removed from the lease. The facility measurement point may be on the lease or off-lease with BLM approval.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located.

Gas means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

Gas plant products means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

Gathering means the movement of lease production to: a central accumulation and/or treatment point on the lease, unit, or communitized area; or a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM operations personnel.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of unprocessed gas, residue gas, and gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as compression, dehydration, measurement, and/or field gathering to the extent that the lessee is obligated to perform them at no cost to the Indian lessor, and payments for gas processing rights. Gross proceeds, as applied to gas, also includes but is not limited to reimbursements for severance taxes and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest is exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Index means the calculated composite price ($/MMBtu) of spot-market sales published by a publication that meets MMS- established criteria for acceptability at the index pricing point.

Index pricing point (IPP) means any point on a pipeline for which there is an index.

Index zone means a field or an area with an active spot market and published indices applicable to that field or area that are acceptable to MMS under § 206.172(d)(4) of this subpart.

Indian allottee means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context. For purposes of this subpart, this definition excludes Federal leases.

Lease products means any leased minerals attributable to, originating from, or allocated to a lease.

Lessee means any person to whom the United States, a Tribe, and/or individual Indian landowner issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality lease products means lease products which have similar chemical, physical, and legal characteristics.

Major portion means the lease term providing that the royalty value may be established considering the highest price paid or offered for the major portion of production in the field or area.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that a purchaser will accept them under a sales contract typical for the field or area.

MMS means the Minerals Management Service, Department of the Interior. MMS includes, where appropriate, Tribal auditors acting under agreements under the Federal Oil and Gas Royalty Management Act, 30 U.S.C. 1701 *et seq.* or other applicable agreements.

Minimum royalty means that minimum amount of production royalty that the lessee must pay for the lease year as specified in the lease or in applicable leasing regulations.

Natural gas liquids (*NGL*'s) means those gas plant products consisting of ethane, propane, butane, and/or heavier liquid hydrocarbons.

Net-back method (or *work-back method*) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, and/or manufacturing are deducted from the proceeds received for, or the value of, the gas, residue gas, or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale under an arm's-length contract or comparison to other sales of such products.

Net output means the quantity of residue gas and each gas plant product that a processing plant produces.

Net profit share means the specified share of the net profit from production of oil and gas as provided in the agreement.

Operating rights owner (*working interest owner*) means any person who owns operating rights in a lease subject to this subpart. A record title owner is the owner of operating rights under a lease except to the extent that the operating rights or a portion thereof have been transferred from record title. (See BLM regulations at 43 CFR 3100.0–5(d)).

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Point of royalty measurement means the same as facility measurement point.

Posted price means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

Residue gas means that hydrocarbon gas consisting principally of methane resulting from processing gas.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of gas, residue gas and gas plant products are made. Selling arrangements are described by illustration in the MMS Royalty Management Program Oil and Gas Payor Handbook.

Spot sales agreement means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration. It also does not normally require a cancellation notice to terminate, and does not contain an obligation, or imply an intent, to continue in subsequent periods.

Takes means when the operating rights owner sells or removes production from, or allocated to, the lease, or when such sale or removal occurs for the benefit of an operating rights owner.

Work-back method means the same as net-back method.

§ 206.172 How to value gas produced from leases in an index zone.

(a) *What leases this section applies to.* (1) This section explains how lessees must value, for royalty purposes, gas produced from Indian leases located in an index zone. For other leases, value must be determined under § 206.174 of this subpart, or as otherwise provided in the lease. You must use the valuation provision of this section if your lease is in an index zone and:

(i) Has a major portion provision, or

(ii) Does not have a major portion provision, but the lease provides for the Secretary to determine the value of production.

(2) This section does not apply to carbon dioxide, nitrogen, or other non-hydrocarbon components of the gas stream. However, if they are recovered and sold separately from the gas stream, the value for these products must be determined under § 206.174 of this subpart.

(b) *How to value residue gas and gas prior to processing.* (1) Except as provided in paragraph (e) of this section, this paragraph (b) explains how you must value:

(i) Gas production prior to processing;

(ii) Gas production that you certify on Form MMS–4410 is not processed before it flows into a pipeline with an index but which may be processed later; and

(iii) Residue gas after processing.

(2)(i) Except as provided in paragraph (b)(2)(ii) of this section, the value of gas production which is not sold under dedicated contracts is the index-based value determined in paragraph (d) of this section.

(ii) If gas not sold under a dedicated contract was subject to a previous contract which was the subject of a gas contract settlement, then you must compare the index-based value determined in paragraph (d) of this section with the value of that gas under § 206.174. You must pay royalty on the higher of those two values.

(3) The value of gas production which is sold under dedicated contracts is the higher of the index-based value under paragraph (d) of this section or the value of that production determined under § 206.174 of this subpart.

(c) *How to value gas that is processed before it flows into a pipeline with an index*. Except as provided in paragraph (e) of this section, this paragraph (c) explains how you must value gas that is processed before it flows into a pipeline with an index. You must value such gas production based on the higher of:

(1) The value of the gas prior to processing determined under paragraph (b) of this section; or

(2) The value of the gas after processing, which is either the alternative dual accounting value under § 206.173 of this subpart or the sum of:

(i) The value of the residue gas determined under paragraph (b)(2) or (b)(3) of this section, as applicable; and

(ii) The value of the gas plant products determined under § 206.174 of this subpart, less any applicable processing allowances determined under this subpart; and

(iii) The value of any drip condensate associated with the processed gas determined under subpart B of this part.

(d) *How to determine the index-based value for gas production.* (1) To determine the index-based value per MMBtu for production from a lease in an index zone, you must:

(i) For each MMS-approved publication, calculate the average of the highest reported prices for all index pricing points in the index zone, except for any prices excluded under paragraph (d)(6) of this section;

(ii) Sum the averages calculated in paragraph (d)(1)(i) of this section and divide by the number of publications;

(iii) Reduce the number calculated under paragraph (d)(1)(ii) of this section by 10 percent, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu. The result is the index-based value per MMBtu for production from all leases in that index zone.

(2) MMS will publish in the Federal Register the index zones that are eligible for the index-based valuation method under this paragraph. MMS will monitor the market activity in the index zones and, if necessary, hold a technical conference to add or modify a particular index zone. Any change to the index zones will be published in the Federal Register. MMS will consider the following factors and conditions in determining eligible index zones:

(i) Areas for which MMS-approved publications establish index prices that accurately reflect the value of production in the field or area where the production occurs;

(ii) Common markets served;

(iii) Common pipeline systems;

(iv) Simplification; and

(v) Easy identification in MMS' systems, such as counties or Indian reservations.

(3) If market conditions change so that an index-based method for determining value is no longer appropriate for an index zone, MMS will hold a technical conference to consider disqualification of an index zone. MMS will publish notice in the Federal Register if an index zone is disqualified. If an index zone is disqualified, then production from leases in that index zone cannot be valued under this paragraph.

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

(i) Publications buyers and sellers frequently use;

(ii) Publications frequently referenced in purchase or sales contracts;

(iii) Publications which use adequate survey techniques, including the gathering of information from a substantial number of sales;

(iv) Publications which publish the range of reported prices they use to calculate their index; and

(v) Publications independent from DOI, lessors, and lessees.

(5) Any publication may petition MMS to be added to the list of acceptable publications.

(6) MMS may exclude an individual index price for an index zone in an MMS-approved publication if MMS determines that the index price does not accurately reflect the value of production in that index zone. MMS will publish a list of excluded indices in the Federal Register.

(7) MMS will reference which tables in the publications you must use for determining the associated index prices.

(8) The index-based values determined under this paragraph are not subject to deductions for transportation or processing allowances determined under §§ 206.177, 206.178, 206.179, and 206.180 of this subpart.

(e) *How you determine the minimum value for royalty purposes.* (1) Notwithstanding any other provision of this section, the value for royalty purposes of gas production from an Indian lease subject to this section cannot be less than the value determined under this paragraph (e).

(2) By June 30 following any calendar year, you must calculate for each month of that calendar year your safety net price per MMBtu using the procedures in paragraph (e)(3) of this section. You must calculate a safety net price for each month and for each index zone where you have an Indian lease for which you report and pay royalties.

(3) Your safety net price for an index zone must be calculated as the volume weighted average contract price per delivered MMBtu under your arm's-length contracts for the disposition of residue gas or unprocessed gas from the same index zone (which, for purposes of this paragraph (e) only, includes gas from your Indian leases and Federal, State, and fee properties). Do not reduce the contract price for any transportation costs incurred to deliver the gas to the purchaser. You should include in your calculation only sales under those contracts that establish a delivery point beyond the first index pricing point to which the gas flows and that include any gas attributable to one or more of your Indian leases in the index zone. For purposes of paragraph (e) of this section only, the contract price will not include:

(i) Any amounts which you receive in compromise or settlement of a predecessor contract for that gas;

(ii) Adjustments for you or any other person to place gas production in marketable condition or to market the gas; or

(iii) Any amounts related to marketable securities associated with that sales contract.

(4)(i) Next, you must determine for each month the number that is 80 percent of the safety net price you calculated for an index zone under paragraph (e)(3) of this section. You also must calculate the number that equals 125 percent of the monthly index-based value. You must perform this calculation separately for each index zone. For any index zone, if the number you calculated as 80 percent of the safety net price exceeds the number you calculated as 125 percent of the index-based value, then you owe additional royalty on the safety net differential determined under paragraph (e)(4)(ii) of this section.

(ii) To calculate the additional royalties you owe, multiply the safety net differential determined in paragraph (e)(4)(i) of this section by the volume of all your gas production from Indian leases in that index zone that was sold beyond the first index pricing point through which the gas flowed and that was used in the calculation in paragraph (e)(3) (''safety net production'').

(iii) Allocate the additional royalties determined under paragraph (e)(4)(ii) of this section to each Indian lease in the index zone with safety net production. For each Indian lease in the index zone with safety net production, allocate the additional royalties owed as follows:

$[(A)/(B)] \times (C)$

Where:

(A) Is volume (in MMBtu's) of safety net production from that Indian lease;

(B) Is volume (in MMBtu's) of safety net production from all your Indian leases in that index zone; and

(C) Is total additional royalties owed.

(5) You have the following responsibilities to comply with the minimum value for royalty purposes:

(i) You must report the safety net price for each index zone to MMS on Form MMS–4411 no later than June 30 following each calendar year.

(ii) You must pay and report on Form MMS–2014 additional royalties due no later than June 30 following each calendar year.

(iii) MMS has 1 year from the date it receives your Form MMS–4411 to order you to amend your safety net price calculation. If MMS does not order any amendments within the 1-year period, your safety net price calculation is final.

§ 206.173 Alternative methodology for dual accounting.

(a) *Election for a dual accounting method.* (1) If you are required to perform the accounting for comparison (dual accounting) under § 206.176 of this subpart, you have two choices. You may elect to perform the dual accounting calculation according to either § 206.176(a) of this subpart (called *actual dual accounting*), or paragraph (b) of this section (called the alternative methodology for dual accounting).

(2)(i) Your election to use the alternative methodology for dual accounting must be made separately for your Indian leases in each MMS-designated area. Your election for a designated area must apply to all of your Indian leases in that area. MMS will publish in the Federal Register a list of the leases that will be associated with each designated area for purposes of this section. The MMS-designated areas are:

(A) Alabama-Coushatta;
(B) Blackfeet Reservation;
(C) Crow Reservation;
(D) Fort Belknap Reservation;
(E) Fort Berthold Reservation;
(F) Fort Peck Reservation;
(G) Jicarilla Apache Reservation;
(H) MMS-designated groups of counties in the State of Oklahoma;
(I) Navajo Reservation;
(J) Northern Cheyenne Reservation;
(K) Rocky Boys Reservation
(L) Southern Ute Reservation;
(M) Turtle Mountain Reservation;
(N) Ute Mountain Ute Reservation;
(O) Uintah and Ouray Reservation;
(P) Wind River Reservation; and
(Q) Any other area that MMS designates. MMS will publish a new area designation in the Federal Register.

(ii) You may elect to begin using the alternative methodology for dual accounting at the beginning of any month. The first election to use the alternative methodology will be effective from the time of election through the end of the following calendar year. Thereafter, each election to use the alternative methodology must remain in effect for 2 calendar years. You may return to the actual dual accounting method only at the beginning of the next election period or with the written approval of MMS and the Tribal lessor for Tribal leases, and MMS for Indian allottee leases in the designated area.

(iii) When you elect to use the alternative methodology, any new wells or newly-acquired leases commencing production in the designated area during the term of the election must use the alternative methodology.

(b) *How to calculate the alternative methodology for dual accounting.*

(1) The alternative methodology adjusts the value of gas prior to processing determined under either § 206.172 or § 206.174 of this subpart to provide an after-processing value. You must use the after-processing value for royalty payment purposes. The amount of the increase depends on your relationship with the owner(s) of the plant where the gas is processed. If you have no direct or indirect ownership interest in the processing plant, then the increase is lower. If you have a direct or indirect ownership interest in the plant where the gas is processed, the increase is higher.

(2)(i) To calculate the alternative methodology for dual accounting, you must apply the increase to the value prior to processing, determined in either § 206.172 or § 206.174 of this subpart, as follows:

Post-processing value = (value determined in either § 206.172 or § 206.174) $\times$ (1 + increment for dual accounting).

(ii) In this equation, the increment for dual accounting is the number you take from the applicable Btu range in the following table:

BTU range	Increment if lessee has no ownership interest in plant	Increment if lessee has an ownership interest in plant
1001 to 1050	.0275	.0375
1051 to 1100	.0400	.0625
1101 to 1150	.0425	.0750
1151 to 1200	.0700	.1225
1201 to 1250	.0975	.1700
1251 to 1300	.1175	.2050
1301 to 1350	.1400	.2400
1351 to 1400	.1450	.2500
1401 to 1450	.1500	.2600
1451 to 1500	.1550	.2700
1501 to 1550	.1600	.2800
1551 to 1600	.1650	.2900
1601 to 1650	.1850	.3225
1651 to 1700	.1950	.3425
1700+	.2000	.3550

(3) The applicable Btu for purposes of this section is the volume weighted-average Btu for the lease computed from measurements at the facility measurement point(s) for gas production from the lease.

(4) If you process any gas from the lease during a month and the weighted-average quality of the gas from the lease that month determined under paragraph (b)(3) of this section is:

(i) Greater than 1,000 Btu's per cubic foot (Btu/cf), all gas production from the lease is subject to dual accounting, and you must use the alternative method for all that gas production;

(ii) Less than or equal to 1,000 Btu/cf, only the volumes of lease production measured at facility measurement points whose quality exceeds 1,000 Btu/cf is subject to dual accounting, and you may use the alternative methodology for these volumes. For gas measured at facility measurement points for these leases where the quality is equal to or less than 1,000 Btu/cf, you are not required to do dual accounting.

§ 206.174 How to value gas production when an index-based method cannot be used.

(a)(1) This section applies to the valuation of gas production when your lease is not in an index zone and any other gas production that cannot be valued under § 206.172 of this subpart. It also applies to the valuation of gas from all Indian leases that is sold under a dedicated contract, to the valuation of gas plant products, and to components of the gas stream that have no Btu value (for example, carbon dioxide, nitrogen, etc.). If your lease is in an index zone and you sell your gas under a dedicated contract, then the value of your gas is the higher of the value under this section or the value under § 206.172 of this subpart.

(2) The value of gas production, for royalty purposes, subject to this subpart is the value of gas determined under this section less applicable allowances determined under this subpart.

(3) You must determine the value of gas production that is processed and is subject to accounting for comparison using the procedure in § 206.176 of this subpart.

(4)(i) This paragraph applies if your lease has a major portion provision. It also applies if your lease does not have a major portion provision but the lease provides for the Secretary to determine value. The value of production you must initially report and pay is the value determined in accordance with the other paragraphs of this section. Within 90 days of each report month, MMS will determine the major portion value and notify you in writing of that value. The value of production for royalty purposes for your lease is the higher of either the value determined under this section which you initially used to report and pay royalties, or the major portion value calculated under this paragraph (a)(4). If the major portion value is higher, you must submit an amended Form MMS–2014 to MMS within 30 days of when you receive written notice from MMS of the major portion value. Late-payment interest under 30 CFR 218.54 on any underpayment will not begin to accrue until the date the amended Form MMS–2014 is due to MMS.

(ii) MMS will calculate the major portion value for each designated area (which are the same designated areas as under § 206.173 of this title) using values reported for unprocessed gas and residue gas on Form MMS–2014 for gas produced from leases on that Indian reservation or other designated area. MMS will array the reported prices from highest to lowest price. The major portion value is that price at which 25 percent (by volume) of the gas (starting from the highest) is sold. MMS cannot unilaterally change the major portion value after you are notified in writing of what that value is for your leases.

(b)(1)(i) The value of gas, residue gas, or any gas plant product you sell under an arm's-length contract is the gross proceeds accruing to you, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. You have the burden of demonstrating that your contract is arm's-length.

(ii) In conducting reviews and audits for gas valued based upon gross proceeds under this paragraph, MMS will examine whether or not your contract reflects the total consideration actually transferred either directly or indirectly from the buyer to you for the gas, residue gas, or gas plant product. If the contract does not reflect the total consideration, then MMS may require that the gas, residue gas, or gas plant product sold under that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to you, including the additional consideration.

(iii) If MMS determines for gas valued under this paragraph that the gross proceeds accruing to you under an arm's-length contract do not reflect the value of the gas, residue gas, or gas plant products because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the gas, residue gas, or gas plant product be valued under paragraphs (c)(2) or (c)(3) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your value.

(2) MMS may require you to certify that your arm's-length contract provisions include all of the consideration the buyer pays, either directly or indirectly, for the gas, residue gas, or gas plant product.

(c) If your gas, residue gas, or any gas plant product is not sold under an arm's-length contract, then you must value the production using the first applicable method as follows:

(1) The gross proceeds accruing to you under your non-arm's-length contract sale (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). For residue gas or gas plant products, the comparable arm's-length contracts must be for gas from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors will be considered: Price, time of execution, duration, market or markets served, terms, quality of gas, residue gas, or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the gas, residue gas, or gas plant products; or

(2) A value determined by consideration of other information relevant in valuing like-quality gas, residue gas, or gas plant products, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, or for residue gas or gas plant products from the same gas plant or other nearby processing plants. Other factors to consider include posted prices for gas, residue gas, or gas plant products, prices received in spot sales of gas, residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the salability of such gas, residue gas, or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) If you determine the value of production under paragraph (c) of this section, you must retain all data relevant to the determination of royalty value. Such data will be subject to review and audit, and MMS will direct you to use a different value if it determines upon review or audit that the value you reported is inconsistent with the requirements of these regulations.

(2) You must make certain data available upon request to the authorized MMS or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other authorized persons. You must make available your arm's-length sales and volume data for like-quality gas, residue gas, and gas plant products that are sold, purchased, or otherwise obtained from the same processing plant or from nearby processing plants, or from the same or nearby field or area.

(e) If MMS determines that you have not properly determined value, you must pay the difference, if any, between royalty payments made based upon the value you used and the royalty payments that are due based upon the value MMS established. You also must pay interest computed on that difference under 30 CFR 218.54. If you are entitled to a credit, MMS will provide instructions how to take that credit.

(f) You may request a value determination from MMS. In that event, you must propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. You must submit all available data relevant to your proposal. MMS will quickly determine the value based upon your proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria this subpart authorizes. That determination will remain effective for the period stated therein. After MMS issues its determination, you must make the adjustments in accordance with paragraph (e) of this section. MMS will provide notice of its decision to the Indian Tribes for their Tribal leases.

(g)(1) For gas, residue gas, and gas plant products valued under this section, under no circumstances may the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for gas, residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined under this subpart.

(2) For gas plant products valued under this section and not valued under § 206.173, the alternative methodology for dual accounting, the minimum value of production for each gas plant product is:

(i)(A) For production from leases in Colorado in the San Juan Basin, New Mexico, and Texas, the monthly average minimum price reported in commercial price bulletins for the gas plant product at Mont Belvieu minus 8.0 cents per gallon.

(B) For production in Arizona, in Colorado outside the San Juan Basin, Minnesota, Montana, North Dakota, Oklahoma, South Dakota, Utah, and Wyoming, the monthly average minimum price reported in commercial price bulletins for the gas plant product at Conway minus 7.0 cents per gallon.

(ii) You may use any commercial price bulletin, but you must use the same bulletin for all of the calendar year. If the commercial price bulletin you are using stops publication, you may use a different commercial price bulletin for the remaining part of the calendar year.

(iii) If you use a commercial price bulletin that is published monthly, the monthly average minimum price is the bulletin's minimum price. If you use a commercial price bulletin that is published weekly, the monthly average minimum price is the arithmetic average of the bulletin's weekly minimum prices. If you use a commercial price bulletin that is published daily, the monthly average minimum price is the arithmetic average of the bulletin's minimum prices for each Wednesday in the month.

(h) You are required to place gas, residue gas and gas plant products in marketable condition at no cost to the Indian lessor unless otherwise provided in the lease agreement. When your gross proceeds establish the value under this section, that value must be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is your responsibility to place the gas, residue gas, or gas plant products in marketable condition.

(i) For gas, residue gas, and gas plant products valued under this section, value must be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if you fail to take proper or timely action to receive prices or benefits to which you are entitled, you must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments must be in writing and signed by all parties to an arm's-length contract. If you make timely application for a price increase or benefit allowed under your contract but the purchaser refuses, and you take reasonable measures, which are documented, to force purchaser compliance, you will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph is not intended to permit you to avoid your royalty payment obligation in situations where your purchaser fails to pay, in whole or in part, or timely, for a quantity of gas, residue gas, or gas plant product.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in an MMS redetermination of value under this section will be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including transportation allowances and processing allowances, may be exempted from disclosure under the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this subpart must be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

(l) Time limitations on adjustments and audits for certain Indian leases.

(1) If you determine the value of production under this section from leases in Montana and North Dakota, you have time limits to make adjustments to your reported royalty value. If you know of an adjustment that would result in additional royalty owed, you are required to report that adjustment and pay the additional royalty by the time limit established in this paragraph. MMS also has time limits to complete royalty audits for these leases only. There are exceptions to these time limits in paragraph (l)(2) of this section.

(i) If your royalty valuation does not include a non-arm's-length allowance under this subpart, you have until the last day of the 13th month following the production month to report any adjustments on Form MMS–2014. MMS must complete royalty audits timely and may not issue demands or orders or initiate other action to collect royalty underpayment for this production from the lessee after the last day of the 12th month following the last day to make adjustments.

(ii) If your royalty valuation includes a non-arm's-length allowance under this subpart, you have until the last day of the 9th month following the month you submit to MMS your actual transportation allowance report, or your actual processing allowance report, to report any adjustments on Form MMS–2014. MMS must complete royalty audits timely and may not issue demands or orders or initiate any other action to collect royalty underpayments for this production from the lessee after the last day of the 12th month after the last day to report adjustments.

(2) Exceptions to the time limits in paragraph (l)(1) of this section are:

(i) If you have a pending dispute with your purchaser, the time periods to make adjustments in paragraphs (l)(1)(i) and (l)(1)(ii) of this section will be extended for 6 months after your dispute is finally resolved. The time period to complete audits and issue demands or orders is correspondingly extended;

(ii) If you have a pending dispute with the person transporting or processing your gas production, the time periods to make adjustments in paragraphs (l)(1)(i) and (l)(1)(ii) of this section will be extended for 6 months after your dispute is finally resolved. The time period to complete audits and issue demands or orders is correspondingly extended;

(iii) If there is a written agreement between you and MMS or its delegee if applicable, the time period is extended for the period stated in the agreement;

(iv) If there is a pending regulatory proceeding by any agency with jurisdiction over sales prices for gas that could affect the value of the gas, the time period to make adjustments in paragraphs (l)(1)(i) and (l)(1)(ii) of this section will be extended for 90 days after final resolution of the pending regulatory proceeding, including any period for judicial review. The time period to complete audits and issue demands or orders is correspondingly extended;

(v) If the lessee fails or refuses to provide records or information in its possession or control necessary to complete the audit, the time period to issue demands or orders will be extended for any time periods that MMS cannot obtain the records or information;

(vi) The time period in paragraphs (l)(1)(i) and (l)(1)(ii) of this section will not apply in situations involving fraud or intentional misrepresentation or concealment of a material fact for the purpose of evading a payment obligation.

(3) For purposes of this paragraph (l), demand or order means an order to pay a specific amount or an amount that the lessee easily may calculate. It also includes an order to perform a restructured accounting based upon repeated, systemic reporting errors for a significant number of leases or a single lease for a significant number of reporting months. The order to perform a restructured accounting must specify the reasons and the factual bases for the order.

(4) If an audit discloses overpayments for any lease, the lessee may credit those overpayments against any underpayments due on that same lease.

§ 206.175 How to determine quantities and qualities of production for computing royalties.

(a) For unprocessed gas, you must pay royalties on the quantity and quality at the facility measurement point BLM either allowed or approved.

(b) For residue gas and gas plant products, you must pay royalties on your share of the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(c) If you have no ownership interest in the processing plant and you do not operate the plant, you may use the contract volume allocation to determine your share of plant products.

(d) If you have an ownership interest in the plant or you operate it, use the following procedure to determine the quantity of the residue gas and gas plant products attributable to you for royalty payment purposes:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which you must pay royalty is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease must be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of non-uniform content, the volumes of residue gas and gas plant products allocable to each lease are based on theoretical volumes of residue gas and gas plant products measured in the lease gas stream. You must calculate the portion of net plant output of residue gas and gas plant products attributable to each lease as follows:

(i) First, compute the theoretical volumes of residue gas and gas plant products by multiplying the lease volume of the gas stream by the tested residue gas content (mole percentage) or gas plant product (GPM) content of the gas stream.

(ii) Second, calculate the theoretical volume of residue gas and gas plant products delivered from all leases by summing the theoretical volumes of residue gas and gas plant products delivered from each lease.

(iii) Third, calculate the theoretical quantities of net plant output of residue gas and gas plant products attributable to each lease by multiplying the net plant output of residue gas and gas plant products by the ratio of the theoretical volume of residue gas and gas plant products delivered from all leases.

(4) You may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If MMS approves a different method, it will be applicable to all gas production from your Indian leases that is processed in the same plant.

(e) You may not take any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas incurred prior to the facility measurement point will not be subject to royalty if BLM determines that the loss was unavoidable.

§ 206.176 How to do accounting for comparison.

(a) This section applies if you process your Indian lease gas and that Indian lease requires accounting for comparison (also referred to as actual dual accounting). Except as provided in paragraphs (b) and (c) of this section, the actual dual accounting value, for royalty purposes, is the greater of:

(1) The combined value of:

(i) The residue gas and gas plant products resulting from processing the gas determined under either § 206.172 or § 206.174 of this subpart, including any applicable allowances; and

(ii) Any drip condensate associated with the processed gas recovered downstream of the point of royalty settlement without resorting to processing determined under § 206.174 of this subpart, including applicable allowances; or

(2) the value of the gas prior to processing determined under either § 206.172 or § 206.174 of this subpart, including any applicable allowances.

(b) If you are required to account for comparison, you may elect to use the alternative dual accounting methodology provided for in § 206.173 of this subpart instead of the provisions in paragraph (a) of this section.

(c) Accounting for comparison is not required for gas if no gas from the lease is processed until after the gas flows into a pipeline with an index located in an index zone. If you do not perform dual accounting, you must certify to MMS that gas flows into such a pipeline before it is processed.

(d) Except as provided in paragraph (e) of this section, if you value any gas production from a lease for a month using the dual accounting provisions of this section (including § 206.173 of this subpart), then the value of that gas is the minimum value for any other gas production from that lease for that month flowing through the same facility measurement point.

(e) If the weighted average Btu quality for your lease is less than 1,000 Btu's per cubic foot, see § 206.173(b)(4)(ii) to determine if you must perform a dual accounting calculation.

§ 206.177 General provisions regarding transportation allowances.

(a) When you value gas under § 206.174 of this subpart at a point off the lease (for example, sales point or point of value determination), you may deduct from value a transportation allowance to reflect the value, for royalty purposes, at the lease. The allowance is based on the reasonable actual costs you incurred to transport unprocessed gas, residue gas, or gas plant products from a lease to a point off the lease. This would include, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant. You may not deduct any allowance for gathering costs.

(b) You must allocate transportation costs among all products you produce and transport as provided in § 206.178 of this subpart.

(c)(1) Except as provided in paragraph (c)(2) of this section, your transportation allowance deduction for each selling arrangement must not exceed 50 percent of the value of the unprocessed gas, residue gas, or gas plant product. For purposes of this section, natural gas liquids are considered one product.

(2) If you ask MMS, it may approve a transportation allowance deduction in excess of the limitations in paragraph (c)(1) of this section. To receive this approval, you must demonstrate that the transportation costs incurred in excess of the limitations in paragraph (c)(1) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances may an allowance reduce the value for royalty purposes under any selling arrangement to zero.

(d) If MMS conducts a review and/or audit and determines that you have improperly determined a transportation allowance authorized by this subpart, then you will be required to pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54. Alternatively, you may be entitled to a credit, but you will not receive any interest on your overpayment.

§ 206.178 How to determine a transportation allowance.

(a) If you have an arm's-length transportation contract, the provisions of this section explain how to determine your allowance.

(1)(i) If you have an arm's-length contract for transportation of your production, the transportation allowance is the reasonable, actual costs you incur for transporting the unprocessed gas, residue gas and/or gas plant products under that contract. Paragraphs (a)(1)(ii) and (a)(1)(iii) of this section provide a limited exception. You have the burden of demonstrating that your contract is arm's-length. Your allowances also are subject to paragraph (f) of this section. You are required to submit to MMS a copy of your arm's-length transportation contract(s) and all subsequent amendments to the contract(s) within 2 months of the date MMS receives your report which claims the allowance on the Form MMS–2014.

(ii) When either MMS or a Tribe conducts reviews and audits, they will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from you to the transporter for the transportation. If the contract reflects more than the total consideration, then MMS may require that the transportation allowance be determined under paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the value of the transportation because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the transportation allowance be determined under paragraph (b) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your transportation costs.

(2)(i) If your arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs must be allocated in a consistent and equitable manner to each of the products transported. To make this allocation, use the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, you cannot take an allowance for the costs of transporting lease production which is not royalty bearing without MMS approval, or without lessor approval on Tribal leases.

(ii) As an alternative to paragraph (a)(2)(i) of this section, you may propose to MMS a cost allocation method based on the values of the products transported. MMS will approve the method if it determines that:

(A) the methodology in paragraph (a)(2)(i) of this section cannot be applied; or

(B) your proposal is more reasonable than the methodology in paragraph (a)(2)(i) of this section.

(3)(i) If your arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, you must propose an allocation procedure to MMS. You may use the transportation allowance determined in accordance with your proposed allocation procedure until MMS decides whether to accept your cost allocation.

(ii) You are required to submit all relevant data to support your allocation proposal. MMS will then determine the gas transportation allowance based upon your proposal and any additional information MMS deems necessary.

(4) If your payments for transportation under an arm's-length contract are not based on a dollar per unit, you must convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a reduction for a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. You may use the transportation factor to determine your gross proceeds for the sale of the product. However, the transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *How to determine a transportation allowance if you have a non-arm's-length or no contract.* (1)(i) This paragraph applies where you have a non-arm's-length transportation contract or no contract, including those situations where you perform transportation services for yourself. In these circumstances, the transportation allowance is based upon your reasonable, allowable, actual costs for transportation as provided in this paragraph.

(ii) All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. You must submit the actual cost information to support the allowance to MMS on Form MMS–4295 within 3 months after the end of the 12-month period to which the allowance applies. However, MMS may approve a longer time period. MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may require you to modify your actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations is based upon your actual costs for transportation during the reporting period. Allowable costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment (in accordance with paragraph (b)(2)(iv)(A)

of this section), or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which you can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which you can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) You may use either depreciation with a return on undepreciated capital investment or a return on depreciable capital investment. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. Once you make an election, you may not change methods without MMS approval. A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for purposes of the allowance calculation. With or without a change in ownership, a transportation system may be depreciated only once. Equipment may not be depreciated below a reasonable salvage value. To compute a return on undepreciated capital investment, you will multiply the undepreciated capital investment in the transportation system by the rate of return determined under paragraph (b)(2)(v) of this section.

(B) To compute a return on depreciable capital investment, you will multiply the initial capital investment in the transportation system by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance will be provided for depreciation. This alternative will apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return is the industrial rate associated with Standard and Poor's BBB rating. The rate of return is the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and is effective during the reporting period. The rate must be redetermined at the beginning of each subsequent transportation allowance reporting period which is determined under paragraph (4) of this section.

(3)(i) The deduction for transportation costs must be determined based on your cost of transporting each product through each individual transportation system. If you transport more than one product in a gaseous phase, the allocation of costs to each of the products transported must be made in a consistent and equitable manner. The allocation should be the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, you may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(ii) As an alternative to the requirements of paragraph (b)(3)(i) of this section, you may propose to MMS a cost allocation method based on the values of the products transported. MMS will approve the method upon determining that:

(A) The methodology in paragraph (b)(3)(i) of this section cannot be applied; or

(B) Your proposal is more reasonable than the method in paragraph (b)(3)(i) of this section.

(4) Your transportation allowance under this paragraph (b) must be determined based upon a calendar year or other period if you and MMS agree to an alternative.

(5) If you transport both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to MMS. You may use the transportation allowance determined in accordance with your proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. You are required to submit all relevant data to support your proposal. MMS will then determine the transportation allowance based upon your proposal and any additional information MMS deems necessary.

(c) *Alternative transportation calculation.* (1) As an alternative to computing your transportation allowance under paragraph (b) of this section, you may use as the transportation allowance 10 percent of your gross proceeds but not to exceed 30 cents per MMBtu.

(2) Your election to use the alternative transportation allowance calculation in paragraph (c)(1) of this section must be made at the beginning of a month and must remain in effect for an entire calendar year. When you first make the election, it will remain in effect until the end of the succeeding calendar year, except for elections effective January 1 which will be effective only for that calendar year.

(d) *Reporting requirements.* (1) If MMS requests, you must submit all data used to determine your transportation allowance. The data must be provided within a reasonable period of time that MMS will determine.

(2) You must report transportation allowances as a separate item on Form MMS–2014. MMS may approve a different reporting procedure on allottee leases, and with lessor approval on Tribal leases.

(e) *Interest assessments if you claim a transportation allowance that is too large.* (1) If you report a transportation allowance which results in an underpayment of royalties, you must pay late-payment interest on the amount of that underpayment.

(2) The interest you are required to pay will be determined under 30 CFR 218.54.

(f) *Adjustments.* If for any month the actual transportation allowance you are entitled to is less than the amount you took on Form MMS–2014, you are required to report and pay additional royalties due plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month you deducted the improper transportation allowance. If the actual transportation allowance you are entitled to is greater than the amount you took on Form MMS–2014 for any royalties during the reporting period, you are entitled to a credit. No interest will be paid on the overpayment.

(g) *Actual or theoretical losses.* If you are paying any specifically identifiable actual or theoretical losses as part of your arm's-length transportation contract, you may deduct those costs. In all other circumstances you may not deduct those costs.

(h) *Other transportation cost determinations.* You must follow the provisions of this section to determine transportation costs when establishing value using either a net-back valuation procedure or any other procedure that allows deduction of actual transportation costs.

§ 206.179 General provisions regarding processing allowances.

(a) When you value any gas plant product under § 206.174 of this subpart, you may deduct from value the reasonable actual costs of processing.

(b) You must allocate processing costs among the gas plant products. You must determine a separate processing allowance for each gas plant product and processing plant relationship. Natural gas liquids are considered as one product.

(c) The processing allowance deduction based on an individual product may not exceed 66⅔ percent of the value of each gas plant product determined under § 206.174 of this subpart. Before you calculate the 66⅔ percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under § 206.177 of this subpart.

(d) Processing cost deductions will not be allowed for placing lease products in marketable condition. These costs include among others, dehydration, separation, compression upstream of the facility measurement point, or storage, even if those functions are performed off the lease or at a processing plant. Costs for the removal of acid gases, commonly referred to as sweetening, are not allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, you will be eligible for a processing allowance determined under this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(e) You will be allowed a reasonable amount of residue gas royalty free for operation of the processing plant, but no allowance will be made for expenses incidental to marketing, except as provided in 30 CFR part 206. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of your residue gas necessary for the operation of the processing plant will be allowed royalty free.

(f) You do not owe royalty on residue gas, or any gas plant product resulting from processing gas, which is reinjected into a reservoir within the same lease, or agreement, until such time as those products are finally produced from the reservoir for sale or other disposition off-lease. This paragraph applies only when the reinjection is included in a BLM-approved plan of development or operations.

(g) If MMS determines that you have determined an improper processing allowance authorized by this subpart, then you will be required to pay any additional royalties plus late-payment interest determined under 30 CFR 218.54. Alternatively, you may be entitled to a credit, but you will not receive any interest on your overpayment.

§ 206.180 How to determine an actual processing allowance.

(a) *How to determine a processing allowance if you have an arms's-length processing contract.* The provisions of this paragraph explain how you determine an allowance under an arm's-length processing contract.

(1)(i) The processing allowance is the reasonable actual costs you incur to process the gas under that contract. Paragraphs (a)(1)(ii) and (a)(1)(iii) of this section provide a limited exception. You have the burden of demonstrating that your contract is arm's-length. You are required to submit to MMS a copy of your arm's-length contract(s) and all subsequent amendments to the contract(s) within 2 months of the date MMS receives your first report which deducts the allowance on the Form MMS–2014.

(ii) When it conducts reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from you to the processor for the processing. If the contract reflects more than the total consideration, then MMS may require that the processing allowance be determined under paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length processing contract does not reflect the value of the processing because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the processing allowance be determined under paragraph (b) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your processing costs.

(2) If your arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product must be determined in accordance with the contract. You cannot take an allowance for the costs of processing lease production which is not royalty-bearing.

(3) If your arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, you must propose an allocation procedure to MMS. You may use your proposed allocation procedure until MMS issues its determination. You are required to submit all relevant data to support your proposal. MMS will then determine the processing allowance based upon your proposal and any additional information MMS deems necessary. You cannot take a processing allowance for the costs of processing lease production which is not royalty-bearing.

(4) If your payments for processing under an arm's-length contract are not based on a dollar per unit, you must convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *How to determine a processing allowance if you have a non-arm's-length or no contract.* (1)(i) This paragraph applies if you have a non-arm's-length processing contract or have no contract, including those situations where you perform processing for yourself. In these circumstances the processing allowance is based upon your reasonable actual costs for processing as provided in paragraph (b) of this section.

(ii) All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. You must submit the actual cost information to support the allowance to MMS on Form MMS–4109 within 3 months after the end of the 12-month period for which the allowance applies. MMS may approve a longer time period. MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may require you to modify your actual processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations is based upon your actual costs for processing during the reporting period. Allowable costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment (in accordance with paragraph (b)(2)(iv)(A) of this section), or a cost equal to the

initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which you can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) You may use either depreciation with a return on undepreciable capital investment or a return on depreciable capital investment. After you elect to use either method for a processing plant, you may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. Once you make an election, you may not change methods without MMS approval. A change in ownership of a processing plant will not alter the depreciation schedule that the original processor/lessee established for purposes of the allowance calculation. However, for processing plants you or your affiliate purchase that do not have a previously claimed MMS depreciation schedule, you may treat the processing plant as a newly installed facility for depreciation purposes. With or without a change in ownership, a processing plant may be depreciated only once. Equipment may not be depreciated below a reasonable salvage value. To compute a return on undepreciated capital investment, you will multiply the undepreciable capital investment in the processing plant by the rate of return determined under paragraph (b)(2)(v) of this section.

(B) To compute a return on depreciable capital investment, you will multiply the initial capital investment in the processing plant by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance will be provided for depreciation. This alternative will apply only to plants first placed in service after March 1, 1988.

(v) The rate of return is the industrial rate associated with Standard and Poor's BBB rating. The rate of return is the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) Your processing allowance under this paragraph (b) must be determined based upon a calendar year or other period if you and MMS agree to an alternative.

(4) The processing allowance for each gas plant product must be determined based on your reasonable and actual cost of processing the gas. You must base your allocation of costs to each gas plant product upon generally accepted accounting principles. You can not take an allowance for the costs of processing lease production which is not royalty-bearing.

(c) *Reporting.*

(1) If MMS requests, you must submit all data used to determine your processing allowance. The data must be provided within a reasonable period of time, as MMS determines.

(2) You must report gas processing allowances as a separate item on the Form MMS–2014. MMS may approve a different reporting procedure for allottee leases, and with lessor approval on Tribal leases.

(d) *Interest assessments if you claim a processing allowance that is too large.* (1) If you report a processing allowance which results in an underpayment of royalties, you must pay interest on the amount of that underpayment.

(2) The interest you are required to pay will be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If for any month the actual gas processing allowance you are entitled to is less than the amount you took on Form MMS–2014, you are required to pay additional royalties plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month you deducted a processing allowance. If the actual processing allowance you are entitled is greater than the amount you took on Form MMS–2014, you are entitled to a credit. However, no interest will be paid on the overpayment.

(f) *Other processing cost determinations.* You must follow the provisions of this section to determine processing costs when establishing value using either a net-back valuation procedure or any other procedure that requires deduction of actual processing costs.

§ 206.181 Processing allowances for use in certain dual accounting situations.

(a) Where accounting for comparison (dual accounting) is required for gas production from a lease but you or someone on your behalf does not process the gas, and you have elected to perform actual dual accounting under § 206.176 of this subpart, you must use the first applicable method as follows to establish processing costs for dual accounting purposes:

(1) The average of the costs established in your current arm's-length processing agreements for gas from the lease, provided that some gas has previously been processed under these agreements; or

(2) The average of the costs established in your current arm's-length processing agreements for gas from the lease, provided that the agreements are in effect for plants to which the lease is physically connected and under which gas from other leases in the field or area is being or has been processed; or

(3) A proposed comparable processing fee submitted to either the Tribe and MMS (for tribal leases) or MMS (for allotted leases) with your supporting documentation submitted to MMS. If MMS does not take action on your proposal within 120 days, the proposal will be deemed to be denied and subject to appeal to the MMS Director under 30 CFR part 290; or

(4) Processing costs based on the regulations in § 206.179 and § 206.180 of this subpart.

Note: Forms are published for comments only and will not be codified in the CFR.

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[GRAPHIC] [TIFF OMITTED] TP23SE96.024

[[**Page** 49917]]

[GRAPHIC] [TIFF OMITTED] TP23SE96.025

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OMB 1010-
Expires

CERTIFICATION FOR NOT PERFORMING ACCOUNTING FOR COMPARISON (DUAL ACCOUNTING)

PAYOR'S NAME ____________________

ADDRESS ____________________

CITY/STATE ____________________ ZIP __________

PAYOR CODE |__|__|__|__|__|

LEASE NUMBER ____________________

DUAL ACCOUNTING IS NOT REQUIRED BECAUSE: (PLEASE SIGN AND DATE)

I certify that gas produced from this property is not processed before entering a pipeline with an index located in an index zone.

Authorized Official ____________________ Date __________

FORM MMS-4410 (8/96)

OMB 1010-
Expires

The Paperwork Reduction Act of 1995 requires us to inform you that this information is being collected to aid the Minerals Management Service in its compliance efforts. 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.

SAFETY NET REPORT

PAYOR'S NAME ______________________

ADDRESS ______________________

CITY/STATE ______________________ ZIP ________

PAYOR CODE |_|_|_|_|_|

REVIEW PERIOD: ______________________

NAME OF INDEX ZONE: ______________________

MONTH	SAFETY NET PRICE (volume weighted average price per MMBtu)	INDEX VALUE ($/MMBtu)	SAFETY NET DIFFERENTIAL* ($/MMBtu)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

* Please refer to 30 CFR § 206.172 (e) (4) (i) for instructions on how to calculate the safety net differential.

Prepared By: ______________________ Phone No. ____________ Date ________

FORM MMS-4411 (8/96)

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