____

(Name) (Address)

______________________________ [SEAL]

(Principal)

____

(Name) (Address)

______________________________ [SEAL]

(Surety)

Certificate as to Corporate Principal

I, ______________, certify that I am the *______________ of the corporation named as principal in the attached bond; that ______________, who signed the bond on behalf of the principal, was then ______________ of that corporation; that I know his signature, and his signature to the bond is genuine; and that the bond was duly signed, sealed, and attested for and in behalf of the corporation by authority to its governing body.

____

[CORPORATE SEAL]

(To be used when no power of attorney has been filed with the port director of customs.)

*May be executed by the secretary, assistant secretary, or other officer of the corporation.

Approved: April 14, 2000.

Raymond W. Kelly,

Commissioner of Customs.

John P. Simpson,

Deputy Assistant Secretary of the Treasury.

[FR Doc. 00–15202 Filed 6–14–00; 8:45 am]

BILLING CODE 4820–02–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 206

RIN 1010–AC72

Amendments to Gas Valuation Regulations for Indian Leases

AGENCY: Minerals Management Service, Interior.

ACTION: Proposed rule.

SUMMARY: The Minerals Management Service (MMS) is proposing to remove the special timing requirements for adjustments and audits of royalties on gas produced from Indian leases in Montana and North Dakota. These timing requirements may force tribal and MMS auditors to expend additional time and money or postpone ongoing audits to meet the restricted time periods. Removing these timing restrictions should increase royalties collected for Indian leases in these States.

DATES: Comments regarding this proposed rulemaking must be received on or before July 17, 2000.

ADDRESSES: If you wish to comment, you may submit your comments by any one of several methods. You may mail comments to David S. Guzy, Chief, Rules and Publications Staff, Minerals Management Service, Royalty Management Program, P.O. Box 25165, MS 3021, Denver, CO 80225–0165. Courier or overnight delivery address is Building 85, Room A–613, Denver Federal Center, Denver, CO 80225. You may also comment via the Internet to RMP.comments@mms.gov. Please submit Internet comments as an ASCII file avoiding the use of special characters and any form of encryption. Please also include ''Attn: RIN 1010–ACT72'' and your name and return address in your Internet message. If you do not receive a confirmation from the system that we have received your Internet message, contact David S. Guzy directly at (303) 231–3432.

FOR FURTHER INFORMATION CONTACT: David S. Guzy, Chief, Rules and Publications Staff, telephone (303) 231–3432, FAX (303) 231–3385, e-Mail David.Guzy@mms.gov.

SUPPLEMENTARY INFORMATION: The principal author of this proposed rulemaking is Mr. Richard Adamski, Royalty Valuation Division, Royalty Management Program (RMP), MMS.

I. General

On August 10, 1999, MMS published a final rule titled ''Amendments to Gas Valuation Regulations for Indian Leases,'' (64 FR 43506) with an effective date of January 1, 2000. These regulations apply to all gas production from Indian (tribal or allotted) oil and gas leases (except leases on the Osage Indian Reservation). The new regulations resulted from a negotiated rulemaking among Indian tribes and allottees, the oil and gas industry, and MMS.

MMS's stated purposes for those amendments to the valuation of gas production were:

(1) To ensure that Indian mineral lessors receive the maximum revenues from mineral resources on their land consistent with the Secretary of the Interior's (Secretary) trust responsibility and lease terms; and

(2) To improve the regulatory framework so that information is available which would permit lessees to comply with the regulatory requirements at the time that royalties are due.

Among the newly adopted regulations was a provision at 30 CFR 206.174(1) requiring that for Indian leases in Montana and North Dakota, lessees must make adjustments to reported royalty values sooner, and MMS must complete its audits sooner, than either has done historically. This provision does not apply to Indian leases in other States.

Under § 2096.174(1), the timing of adjustments and audits depends on whether allowances are arm's-length or non-arm's-length. If the lessee's royalty value has arm's-length transportation or processing allowances, or no allowances, then: (1) The lessee must make all adjustments to value within 13 months of the production month; and (2) MMS must conclude any audit and order any adjustments to royalty value within 12 months after the lessee's adjustment reporting date. If the lessee's royalty value has non-arm's-length transportation or processing allowances, then: (1) the lessee must make all adjustments to value within 9 months of the date the lessee submits the actual cost allowance report to MMS; and (2) MMS must conclude any audit and order any adjustments to royalty value within 12 months after the lessee's adjustment reporting date.

The final rule limited the adjustment and audit period to Indian leases in Montana and North Dakota because, unlike most other producing regions, there are no acceptable published indexes applicable to that area (64 FR 43510). In areas where this occurs, valuation must be based on other criteria which are most difficult to determine than index prices. Industry was concerned that if audits were not to occur until several years after the production month, any underpayments would include substantial late payment charges. The purpose of § 206.174(1) was to accelerate the audit schedule to provide more valuation certainly for both the lessee and the Indian lessor at an earlier date.

Representatives of Montana and North Dakota tribal and allotted lessors strongly oppose these time limits. They believe that the 1-year audit period is unreasonable and may compromise MMS's efforts to maximize revenues for gas produced from Indian leases consistent with its trust responsibility and lease terms. MMS shares the concern that in areas that do not have published indexes, auditors must be afforded adequate time to take the necessary steps to do quality audits. This may be difficult to accomplish under time limits that are absolute.

MMS and tribal auditors also must retain the discretion to allocate audit resources to obtain the best data when that data becomes available. Indian representatives from Montana and North Dakota believe that time restrictions will force the tribes (especially those tribes with audit programs) and MMS auditors to expend additional time and funds to complete audits and take other necessary actions within the restricted time period. For the most part, the tribes in Montana and North Dakota are the least able to bear the costs of such burdens. In some cases, this will force the tribes to postpone or abandon on-going audits of earlier periods to meet the new deadlines.

Moreover, upon further consideration, MMS believes the reason for placing time limits only on Indian leases in Montana and North Dakota (because there are no acceptable published indexes applicable to that area) is not compelling. The final Indian gas rule (§ 206.172(f) and (g)) permits MMS to exclude Indian tribal leases (upon request of the tribe) or Indian allotted leases (after consultation with the Bureau of Indian Affairs) in any State from valuation under the index-based methodology. To Date, MMS has excluded two tribes and two allotted groups from valuation under this method. Under § 206.172(f)(1)(i) and (g)(1)(ii) of the new regulations, lessees of those tribes and allotted groups therefore must value gas produced from those excluded Indian leases under 30 CFR 206.174, the same section that governs the valuation of gas produced from Indian leases in Montana and North Dakota. Yet,the adjustment and audit time limits in § 206174(l) do not apply to those excluded leases—they apply only to those Indian leases in Montana and North Dakota (64 FR 43510). For this reason, representatives of Montana and North Dakota Indian lessors believe that to the extent time restrictions and additional burdens were placed on the Montana and North Dakota leases alone, they are unfair and represent unwarranted disparate treatment.

Therefore, MMS is proposing to remove § 206.174(1) from the regulation. MMS specifically seeks comment on whether there is a valid reason for differentiating between leases located in other States and leases in Montana and North Dakota when they both may be required to use the same valuation standards. MMS also seeks comments on whether the time limitations on adjustment and audit could have a negative revenue impact on royalties collected from gas produced from Indian lands in Montana and North Dakota.

II. Procedural Matters

1. Public Comment Policy

MMS is limiting the comment period for this proposed rule to 30 days after the date of publication in the **Federal Register** rather than the standard 60 days. MMS believes a 30-day comment period is adequate because the language we propose to remove was recently the subject of an extensive comment period. Because this provision did not receive extensive comments during that period, and the change we are proposing is limited, we believe a 30-day comment period is sufficient.

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

2. Summary Cost and Benefit Data

The objective of this proposed rule is to remove the special timing requirements for adjustments and audits of royalties on gas produced from Indian leases in Montana and North Dakota. We have summarized below the estimated costs and benefits of this rule to the three affected groups: Indian lessors in Montana and North Dakota, industry, and the Federal Government. The cost and benefit information in this Item 2 of Procedural Matters is used as the basis for the Departmental certifications in Items 3–11.

A. Indian Lessors in Montana and North Dakota

In 1997, we estimate that auditors collected additional revenues amounting to 2 percent of the total royalties paid for gas production on certain Indian leases located in Montana.

In 1999, payors submitted about $420,000 in royalties from gas produced from Indian leases in Montana and $49,000 in royalties from gas produced from Indian leases in North Dakota. Using 2 percent to calculate the additional audit revenues that may be expected for the 1999 sales year, MMS should collect an additional $8,400 from leases in Montana and $980 from leases in North Dakota. We conclude that if audits cannot be completed within 1 year of the royalty line adjustments timeframes, Indian lessors could potentially lose these additional revenues, plus applicable late payment interest, annually.

B. Industry

This proposed rule will impose no new reporting burdens on industry. Industry will benefit from the proposed rule by being able to make adjustments to royalty lines beyond the current 1-year period. However, industry will pay an undetermined amount of additional interest on any underpayments discovered during audits that take longer than 1 year to complete.

Small Business Issues. Approximately 17 entities in Montana and 5 entities in North Dakota—most of which are small businesses because they employ 500 or less employees—pay royalties to MMS on gas produced from Indian leases. As discussed above, these 22 entities will pay less than $10,000 in additional royalties annually as a result of an extended adjustment and audit period. This proposed rule benefits small tribes that would otherwise have to hire additional audit staff to handle the burden of performing both past and present audits concurrently. From this information, we conclude that this rule will not have a significant economic impact on a substantial number of small entities.

C. Federal Government

Removing the time limits on audit will help 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.

D. Summary of Costs and Benefits to Affected Groups

Description (see corresponding narrative above)	<Cost>/Benefit amount	
	First year	Subsequent years
Indian Lessors in Montana and North Dakota	$9,380 plus interest	$9,380 plus interest.

Description (see corresponding narrative above)	<Cost>/Benefit amount	
	First year	Subsequent years
Industry	<$9,380 plus interest>	<$9,380 plus interest>.
Federal Government	<0>	<0.>.
Net <Cost> or Benefit	<0>	<0.>.

3. Regulatory Planning and Review (E.O. 12866)

This document is not a significant rule and is not subject to review by the Office of Management and Budget under Executive Order 12866.

(1) This proposed rule will not have an effect of $100 million or more on the economy. It will not adversely affect in a material way the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.

(2) This proposed rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency.

(3) This proposed rule will not alter the budgetary effects or entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

(4) This proposed rule does not raise novel legal or policy issues.

4. The Regulatory Flexibility Act

The Department of the Interior certifies that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). See Small Business Issues in Item #2.B. above.

Your comments are important. The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions in this rule, call 1–888–734–3247.

5. Small Business Regulatory Enforcement Act (SBREFA)

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

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

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

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

6. Unfunded Mandates Reform Act

This rule will not impose an unfunded mandate on State, local or tribal governments or the private sector of more than $100 million per year. The rule will not have a significant or unique effect on State, local, or tribal, governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

7. Takings (E.O. 12630)

In accordance with Executive Order 12630, this proposed rule does not have significant takings implications. This rule does not impose conditions or limitations on the use of any private property; consequently, a takings implication assessment is not required.

8. Federalism (E.O. 13132)

In accordance with Executive Order 13132, this proposed rule does not have Federalism implications. This rule does not substantially or directly affect the relationship between Federal and State governments or impose costs on States or localities.

9. Civil Justice Reform (E.O. 12988)

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

10. Paperwork Reduction Act of 1995

This proposed rule does not contain an information collection, as defined by the Paperwork Reduction Act, and the submission of Office of Management and Budget Form 83–I is not required.

11. National Environmental Policy Act

This proposed rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the National Environmental Policy Act of 1969 is not required.

12. Clarity of This Regulation

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this rule easier to understand, including answers to questions such as the following: (1) Are the requirements in the rule clearly stated? (2) does the rule contain technical language or jargon that interferes with its clarity? (3) Does the format of the rule (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity? (4) Would the rule be easier to understand if it were divided into more (but shorter) sections? (A "section" appears in bold type and is preceded by the symbol "§" and a numbered heading; for example, § 206.174 How do I value gas production when an index-based method cannot be used?) (5) Is the description of the rule in the SUPPLEMENTARY INFORMATION section of the preamble helpful in understanding the proposed rule? What else could we do to make the rule easier to understand.

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

List of Subjects in 30 CFR Part 206

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

Dated: June 7, 2000.

Sylvia. V. Baca,

Assistant Secretary—Land and Minerals Management.

For reasons stated in the preamble, MMS proposes to amend 30 CFR part 206 as follows:

PART 206—PRODUCT VALUATION

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

Authority: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2102 *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.*

§ 206.174 [Amended]

2. In § 206.174, remove paragraph (1).

[FR Doc. 00–15201 Filed 6–14–00; 8:45 am]

BILLING CODE 4310–MR–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Care Financing Administration

42 CFR Part 405

[HCFA–3432–N3]

RIN 0938–AJ31

Medicare Program; Criteria for Making Coverage Decisions; Extension of Comment Period

AGENCY: Health Care Financing Administration (HCFA), HHS.

ACTION: Notice of extension of comment period for notice of intent to publish a proposed rule.

SUMMARY: This document extends the comment period for the notice of intent published in the **Federal Register** on May 16, 2000, (65 FR 31124). In that document we announced our intention to publish a proposed rule and solicited advance public comments on the criteria we would use to make certain national coverage decisions and the criteria our contractors would use to make local coverage decisions.

DATES: The comment period is extended to 5 p.m. on July 17, 2000.

ADDRESSES: Mail written comments (one original and three copies) to the following address ONLY: Health Care Financing Administration, Department of Health and Human Services, Attention: HCFA–3432–NOI, P.O. Box 8016, Baltimore, MD 21244–8016.

If you prefer, you may deliver, by courier, your written comments (one original and three copies) to one of the following addresses:

Room 443–G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201, or

C5–14–03, Central Building, 7500 Security Boulevard, Baltimore, MD 21244–1850.

Comments mailed to those addresses may be delayed and received too late for us to consider them.

Because of staffing and resource limitations, we cannot accept comments by facsimile (FAX) transmission. In commenting, please refer to file code HCFA–3432–NOI. Comments received timely will be available for public inspection as they are received, generally beginning approximately 3 weeks after publication of a document, in Room 443–G of the Department's offices at 200 Independence Avenue, SW., Washington, DC, on Monday through Friday of each week from 8:30 a.m. to 5 p.m. (Phone: (202) 690–7890).

FOR FURTHER INFORMATION CONTACT: Susan Gleeson, (410) 786–0542.

SUPPLEMENTARY INFORMATION: On May 16, 2000, we issued a notice of intent to publish a proposed rule in the **Federal Register** (65 FR 31124). The comment period would close on June 15, 2000. Because of the scope of the notice of intent, several organizations that would be affected by the policies requested more time to analyze the potential consequences of the notice of intent. Therefore, we are extending the public comment period until July 17, 2000. We will also hold a Town Hall Meeting to facilitate public discussion. We will publish a **Federal Register** notice announcing the meeting specifics when available. This information will also be available on our web page @ *www.hcfa.gov/quality.*

Authority: Secs. 1102 and 1871 of the Social Security Act (42 U.S.C. 1302 and 1395hh).

(Catalog of Federal Domestic Assistance Program No. 93.773, Medicare—Hospital Insurance; and Program No. 93.774, Medicare—Supplementary Medical Insurance Program)

Dated: June 2, 2000.

Nancy-Ann Min DeParle,

Administrator, Health Care Financing Administration.

Approved: June 12, 2000.

Donna E. Shalala,

Secretary.

[FR Doc. 00–15198 Filed 6–14–00; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF TRANSPORTATION

Coast Guard

46 CFR Parts 10, 12, and 15

[USCG 1999–5610]

RIN 2115–AF83

Training and Certification for Mariners Serving on Certain Ships Carrying More Than 12 Passengers on International Voyages

AGENCY: Coast Guard, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to establish requirements of training and certification for mariners serving on ships—other than roll-on/roll-off (Ro-Ro) ships, covered by another rule—carrying more than 12 passengers on international voyages. (These requirements would not apply to any passenger ships on domestic voyages.) Regulation V/3 of the International Convention for Standards of Training, Certification and Watchkeeping for Seafarers, 1978 (STCW), as amended in 1997, mandated that its Parties ensure this training and certification. This rule would reduce human error, improve the ability of crewmembers to assist passengers during emergencies, and promote safety.

DATES: Comments and related material must reach the Facility of the Docket Management System, or DMS (see **ADDRESSES**), on or before September 13, 2000. Comments sent to the Office of Management and Budget (OMB) (see **ADDRESSES**), on collection of information must reach OMB on or before August 14, 2000.

ADDRESSES: You may submit your comments and related material by any one, but only one, of the following methods:

(1) By mail to the DMS [USCG 1999–5610], U.S. Department of Transportation (DOT), room PL–401, 400 Seventh Street SW., Washington, DC 20590–0001.

(2) In person to the DMS at room PL–401 on the Plaza level of the Nassif Building, 400 Seventh Street SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is 202–366–9329.

(3) By fax to the DMS at 202–493–2251.

(4) Electronically through the Web Site for the DMS at http://dms.dot.gov.

If you submit comments on collection of information to the docket, you must also submit them to the Office of Information and Regulatory Affairs, OMB, 725 17th Street NW., Washington, DC 20503, ATTN: Desk Officer, U.S. Coast Guard.

The DMS maintains the public docket for this rulemaking. Comments and material received from the public, as well as documents mentioned in this preamble as being available in the docket, will become part of this docket and will be available for inspection or copying at room PL–401 on the Plaza level of the Nassif Building, 400 Seventh Street SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. You may also find this docket on the Internet at http://dms.dot.gov.

You may inspect the material proposed for incorporation by reference at room 1210, U.S. Coast Guard

Tuesday
August 10, 1999

Part IV

Department of the Interior

Minerals Management Service

30 CFR Parts 202 and 206

Amendments to Gas Valuation Regulations for Indian Leases; Final 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: Final rule.

SUMMARY: The Minerals Management Service (MMS) is amending its regulations governing the valuation for royalty purposes of natural gas produced from Indian leases. These changes add alternative valuation methods to the existing regulations to ensure that Indian lessors receive maximum revenues from their mineral resources as required by the unique terms of Indian leases and MMS's trust responsibility to the Indian lessor. Further, these changes will improve the accuracy of royalty payments at the time the royalties are due.

DATES: The effective date of this final rule is January 1, 2000.

ADDRESSES: David S. Guzy, Chief, Rules and Publications Staff, Minerals Management Service, Royalty Management Program, PO Box 25165, MS 3021, Denver, Colorado 80225. Courier address is Building 85, Denver Federal Center, Denver, Colorado 80225. E-mail address is RMP.comments@mms.gov.

FOR FURTHER INFORMATION CONTACT: David S. Guzy, Chief, Rules and Publications Staff; phone (303) 231–3432; fax (303) 231–3385; e-mail david.guzy@mms.gov.

SUPPLEMENTARY INFORMATION: The principal authors of this final rule are Donald T. Sant and Richard Adamski of the Royalty Management Program, MMS, and Peter Schaumberg of the Office of the Solicitor, Department of the Interior.

I. Background

MMS's purposes in revising the current regulations regarding the valuation of gas production from Indian leases are:

(1) To ensure that Indian mineral lessors receive the maximum revenues from mineral resources on their land consistent with the Secretary of the Interior's (Secretary) trust responsibility and lease terms; and

(2) To improve the regulatory framework so that information is available which would permit lessees to comply with the regulatory requirements at the time that royalties are due.

II. Comments on Proposed Rule

On September 23, 1996, MMS published a notice of proposed rulemaking (61 FR 49894) to amend the valuation regulations for gas production from Indian leases. The framework for the proposed rule was the product of an Indian Gas Valuation Negotiated Rulemaking Committee (the Committee). The proposed rulemaking provided for a 60-day comment period, which ended November 22, 1996, and was extended to December 3, 1996 (61 FR 59849, November 25, 1996). During the public comment period, MMS received 13 written comments: seven responses from industry, four from industry trade groups or associations, one from an Indian tribe, and one from an Indian agency. A public hearing was held in Oklahoma City, Oklahoma, on October 23, 1996. MMS reopened the public comment period until April 4, 1997 (62 FR 10247, March 6, 1997) to receive comments on the issue of proceeds received from contract settlements. Two comments were received: one from industry and one from an industry trade association.

MMS has considered carefully all of the public comments received during this rulemaking. MMS hereby adopts final regulations governing the valuation of gas produced from Indian leases. These regulations will apply prospectively to gas produced on or after the effective date specified in the DATES section of this preamble.

This final rule reflects certain changes to the proposed rule. However, none of these changes are significant in that they affect the basic structure or approach of the new gas valuation rules.

General Comments

All commenters endorsed the concept of revising the existing regulations to provide simplicity and certainty, decrease administrative costs, and decrease litigation. Industry generally supports the use of independent published index prices for valuing gas produced from Indian leases. Industry also supports the concept of an alternative ''percentage increase'' to satisfy the dual accounting requirement contained in most Indian leases to the extent the lessee chooses to use this alternative methodology voluntarily. Industry objects to the following parts of the proposed rule:

- The safety net concept for nondedicated sales.
- The separate dual accounting requirement on natural gas liquids.
- The gross proceeds requirement if gas production was subject to a previous contract that was part of a gas contract settlement.

The Rocky Mountain Oil and Gas Association (RMOGA) states in its comments that ''it believes the inclusion of a safety net provision is a profound violation of the original consensus on gross proceeds and major portion lease requirements.'' RMOGA also states that ''Indeed, the concept of a safety net was not raised until many months after the vote on the formula had been taken.'' The Independent Petroleum Association of Mountain States (IPAMS) also objects to ''the belated introduction of the ''safety net'' requirement which, as discussed in more detail below, undermines the compromise that was reached on the major portion index value and dual accounting formulae.'' The Council of Petroleum Accountants Societies (COPAS) states ''The COPAS representative on the Committee voted in favor of the original index-based formula at the Committee's May 1995 meeting based on the belief that the use of that formula would satisfy both the gross proceeds and major portion clauses contained in most Indian leases, with the exception of gas sold under certain high-priced dedicated contracts. The record will show that this was clearly the focus of the Committee's discussions leading up to the vote, and that the prospect of a ''safety net'' for nondedicated contracts was not raised until several months later, and came as a surprise to the industry members.''

Response. A review of the record generally contradicts these comments. The first formal proposals for valuation of gas production using index formulas were made at the April 12–13, 1995, meeting of the Committee. The proposal of the Federal Government members was patterned after the Federal Gas Valuation Negotiated Rulemaking Committee proposal (Final Report, March 1995) and included an analysis of gross proceeds for sales before the index point to ensure the validity of index-based values. The proposal offered by the Indian representatives included the concept of a safety net. The proposal to be taken back to the committee members' constituents, dated April 13, 1995, 2:45 p.m. version, stated that ''a safety net must be developed to protect the Indian lessor in certain circumstances.''

The meeting notes for the June 14–15, 1995, meeting at which the index formula was adopted included, under the ''safety net'' heading: ''big discussion as to what to compare to the formula value. Is it the amount accruing to the lessee (because we do not want to use the term gross proceeds)?'' A subgroup was formed at the July 12–13, 1995, meeting to bring safety net options to the next meeting. A second subgroup was formed at the August 8–10, 1995, meeting to further analyze the options for the safety net. The options these subgroups developed all had some concept of obtaining additional royalty for high-value sales beyond the index-pricing point or of gathering data to validate the index. The safety net was voted on and approved at the next meeting on October 17–19, 1995.

Certainly, the group may have adopted a different proposal had different dynamics occurred within the group or a different sequence of events occurred. But the proposed safety net was a product of the decisions the Committee made.

MMS and the one Indian commenter believe that the safety net is an essential part of the proposed rule, and MMS will retain the safety net in the final rule. The Indian comment aptly summarizes the issue: ''The once-a-year calculation of a safety net price is a small concession by Indian lessees to accomplish certainty and to foster general confidence in the validity of the published index prices. The calculation of the safety net price does not require a detailed ''tracing'' of molecules produced from all Indian leases to all distant sales points.'' In addition, the regulation permits only 1 year for MMS to verify a lessee's safety net calculation. There should not be a continuation of audit disputes and litigation over the safety net or problems in administering it.

MMS agrees that the gross proceeds requirement in the proposed rule dealing with the issue of gas contract settlements changed the Committee's agreement that the index formula was to replace both the gross proceeds requirement and the major portion requirement. The comment period was specifically reopened to address this issue. Only two comments were received. In addition, courts in two different circuits have issued decisions in gas contract settlements cases during and after the comment period, as explained more fully below, that affect the handling of the gas contract settlements issue in this rule. This final rule includes the concept that some contract settlement proceeds are royalty bearing, as explained below, but does not require a monthly gross proceeds comparison to the index formula. Those contract settlement proceeds that are royalty-bearing will be part of gross proceeds when value is determined by gross proceeds. Examples include production under a dedicated contract and gas produced in nonindex areas where the initial value is determined by gross proceeds. For index areas, MMS will require the gross proceeds for gas sold under nondedicated contracts to be calculated only if the contract settlement proceeds per MMBtu, when added to 80 percent of the safety net price, exceed the index formula value for the month, including any increase for dual accounting. This computation would be made after the safety net prices were reported to MMS by the lessee.

After publication of the final rule, MMS plans to hold training sessions with industry to illustrate the various procedures for computing value under this rule.

Specific Comments and Other Principal Changes to the Proposed Rule

Comment on § 202.550(a)(1)—now § 202.550(b). MMS received five comments on this issue. The commenters did not object to the tribe rather than MMS deciding when the lessor would take gas as royalty in kind as long as the Indian lessor was subject to the same rules of notification with which MMS must comply.

Response. The tribe will abide by the terms of notification in the lease. No change is made in the final rule.

Comment on § 202.550(a)(2)—now § 202.550(d). MMS specifically requested comment on whether the Department should continue to approve requests for royalty rate reductions on allotted leases when a lessee demonstrates economic hardship. Twelve commenters believe that MMS should continue to provide this approval because of the difficulty in identifying and locating allottee lessors. Two commenters believe that the lease language and the language in 25 U.S.C. 396 do not expressly allow the Secretary to approve a reduction without full consent of every lessor.

Response. MMS agrees that under current law the Secretary may not approve royalty rate reductions without full consent. No change is made in the final rule.

Comment on § 202.550(b)—now § 202.551. Four commenters supported the concept that you should pay royalties on your entitled share of gas production from Indian leases not in approved Federal unit or communitization agreements rather than on your actual takes.

Response. MMS disagrees and we changed the final rule to require royalties on your actual takes for leases not in an approved Federal agreement (AFA). This is consistent with the requirement for Federal leases under the Royalty Simplification and Fairness Act of 1996 (Pub. L. 104–185, as corrected by Pub. L. 104–200). If another person takes some of your entitled share but does not pay for the royalties owed, you are liable for those royalties.

Comment on § 202.550(d)—now § 202.555. Five commenters stated that transportation field fuel and reinjected unprocessed gas, gas plant products, and residue should also be listed as gas not subject to royalty.

Response. Any production that is reinjected and is not produced from the lease, is not subject to royalty until it is again produced and removed from the lease. Transportation field fuel is subject to the requirements of the regulation. We do not believe the suggested change is necessary.

Structure changes to part 202. In an effort to make the final rule easier to read, we restructured § 202.550 to create more sections with headings. Also, we made some changes to clarify the regulatory provisions in this part. None of these changes were intended to change the principal intent of the rule.

One change was made to proposed § 202.550(b), now § 202.551. This section explains the volumes for which you must pay royalties for leases not committed to an approved Federal unit or communitization agreement. Under this section you are liable for royalties on your entitled share of production. Thus, if you hold 40 percent of the operating rights, you are liable for 40 percent of the royalties. However, under this section you must report and pay royalties based on your takes. So if you take 30 percent of the gas production, you must report and pay on that volume. The same applies if you take 50 percent. To address concerns about liability for volumes not taken, we added a new provision to this section so that all interest owners for the lease may ask MMS for permission to report and pay on entitlements. If MMS grants the request, it will provide valuation instructions consistent with the provisions in part 202 for over-taken and under-taken volumes. See the new §§ 202.552, 202.553, and 202.554 (proposed § 202.550(c)) which explain how to value over-taken and under-taken volumes for leases in approved Federal unit or communitization agreements. MMS will apply a similar approach for stand-alone leases.

Comment on § 206.170(c). Eleven commenters believe that the lessee and tribal lessor should be allowed to negotiate alternate valuation methods on their own without MMS approval. The commenters agree that MMS should be part of the negotiation process between lessees and allottees.

Response. MMS is confident that tribes can negotiate independently with lessees. Consistent with the Secretary's trust responsibility, MMS will review and approve agreements for alternate valuation methodologies that are negotiated by the tribe and do not breach the trust responsibility of the Secretary. MMS will take a more active role in negotiations between lessees and allottee lessors. MMS does not believe it is necessary to change the language in the final rule.

Comment on § 206.171. Ten commenters recommend that the definition of ''marketing affiliate'' be reinstated in the final rule. Two commenters noted that in the definition of ''posted price'' it is unnecessary and misleading to refer to marketable condition. They state that gas, in a publicly available price bulletin, is by definition in marketable condition.

Response. We know of no company that meets the requirements of the regulatory definition of ''marketing affiliate'' at 30 CFR 206.171. MMS did not include the definition in the final rule. MMS agrees that the definition of ''posted price'' is unnecessary and has removed the definition in the final rule. MMS has also removed references to ''posted price'' under the benchmarks at § 206.174(c)(2) and the transportation factor under § 206.178(a)(5).

Comment on § 206.172. One commenter listed the following concerns:

• How would a publication become approved?

Response. Publications will be approved if they meet MMS's criteria, which are listed under § 206.172(d)(4).

• What kind of market condition changes will be considered to require a Technical Conference for disqualifying an index zone?

Response. MMS will closely monitor the market sales prices realized in the short and long-term markets. If it appears that index-based values no longer represent reasonable values obtained in the entire market, then MMS will convene a Technical Conference.

• How often will MMS publish the list of acceptable publications in the **Federal Register**?

Response. We plan to update the list of acceptable publications whenever we need to add a new publication or we need to drop a current publication.

• How will independent payors who do not receive the **Federal Register** be notified?

Response. MMS will make sure that all payors are notified through periodic ''Dear Payor Letters'' and publication of those letters on the Internet.

• Which tables within the publications will be used and can they vary from month to month?

Response. When MMS publishes the list of acceptable publications, we will be very specific as to the proper tables and pipelines within the publications you should use in computing the index-based formula price.

• How will MMS determine that the published price does not reflect value accurately?

Response. MMS will closely monitor published prices and compare them to prices published in other publications and to prices received in the entire gas market. MMS will investigate price changes.

• Does this mean each payor will have to subscribe to all MMS-approved publications?

Response. No, MMS will calculate the index-based formula price for each index zone on a monthly basis and provide this information to all interested payors.

• Why is a safety net price required if rates have been accepted by MMS previously?

Response. The safety net price is intended to capture the significantly higher values for sales occurring beyond the index point.

Comment on § 206.172(b)(1)(ii). Two commenters recommended that this paragraph be modified to refer to gas that is not processed before it flows into a mainline and should not be limited to pipelines with an index point.

Response. The Committee spent time discussing the best way to describe when and where gas is or is not processed. The Committee believed the term ''mainline'' was not used consistently throughout the industry. MMS will change § 206.176 of this title to state that dual accounting is not required if gas is not processed before it flows into a mainline pipeline for nonindex areas. MMS believes that for index areas the language of the proposed rule is the proper terminology. We did not define ''mainline'' but intend to have the same characteristics as a pipeline in an index zone with an index.

Comment on § 206.172(b)(2)(ii)—now 206.172(b)(2). Twelve commenters objected to the inclusion of the contract settlement provision in the proposed rule because in addition to the index-based value calculation, it would require a gross proceeds calculation. The same commenters stated that the Committee did not agree to include gas contract settlement language and recommended that this paragraph be deleted. One commenter supported the inclusion of gas contract settlement language because of the position that royalty is due, at a minimum, on all the components of a lessee's gross proceeds.

Response. The Committee was unable to reach consensus on the issue of contract settlements. The Committee spent considerable time discussing whether contract settlement amounts should be included in the safety net calculation. The Committee agreed to language in the proposed rule which would exclude contract settlement amounts from the safety net value and agreed to address the issue in 30 CFR 206.172 of the proposed rule.

MMS acknowledges that the issue of royalty on contract settlement proceeds is currently in litigation. Under judicial decisions issued as of the time of this rule, some contract settlement payments are or may be royalty-bearing while others are not. The final rule includes contract settlement amounts as part of royalty value only when value is determined by gross proceeds and only when the contract settlement payment is of the type that is royalty-bearing as a part of gross proceeds. Value is determined by gross proceeds when valuing production sold under dedicated contracts or the initial value in nonindex areas. For nondedicated contracts, gross proceeds will only need to be calculated when the safety net price plus the royalty-bearing contract settlement proceeds increment exceeds the index formula value including the dual accounting increase. We will modify the current policy whenever necessary to conform with the outcome of ongoing litigation.

This rule does not change which contract settlement payments are royalty-bearing or to what extent a particular payment is royalty-bearing. If and to the extent that a particular contract settlement payment would be royalty-bearing as part of the lessee's gross proceeds before this rule, it is royalty-bearing under this rule when value is determined by gross proceeds. If a contract settlement payment is not royalty-bearing before this rule, it likewise has no royalty consequence under this rule.

In *Mobil Exploration and Producing U.S. Inc.* (MMS–94–0151–OCS, May 4, 1998), the Department determined that contract settlement payments to buy out of the terms of a gas contract and terminate the sales relationship entirely are not royalty-bearing. It also determined that payments to compromise Mobil's purchaser's liability for accrued but unpaid take-or-pay liabilities were not royalty-bearing.

In *United States* v. *Century Offshore Management Corp.,* 111 F.3d 443 (6th Cir., 1997), the Sixth Circuit Court of Appeals concluded that MMS could collect royalties on what MMS had identified as a ''buydown'' payment.

Comment on § 206.172(c)(1) and (2). Two commenters suggested that these paragraphs should make it clear that both transportation and processing allowances are used in dual accounting. These same commenters stated that the reference in paragraph (c)(2)(iii) to subpart B of this part should be more specific.

Response. We have included ''and/or transportation allowances'' in § 206.172(c)(2)(ii). The reference to the entire subpart B of this part is necessary so that drip condensate may be valued correctly under various sale scenarios.

Comment on § 206.172(d) (1) through (6). One commenter stated that the index-based valuation formula accomplished the Committee's goals of availability, timeliness, and satisfying the Indian lease language. One commenter believed that the 10 percent reduction to the index-based value may be considerably lower than actual transportation prices. This commenter suggests the reduction should be between 15 and 20 percent. Five commenters recommended that MMS should clarify in § 206.172(d)(6) that individual index prices will be excluded if MMS determines the index price does not accurately reflect the value of production in that index zone ''on a prospective basis only.''

Response. The 10 percent reduction to the index-based value was a compromise reached by the Committee to reflect average transportation costs. MMS believes that this percentage combined with the administrative savings realized by not having to file forms and track actual costs should adequately compensate the lessee in most cases. MMS believes that § 206.172(d)(6) makes clear our intent to exclude an individual index price only after notification by publication in the **Federal Register**. We do not believe the suggested change adds to or clarifies the sentence.

Comment on § 206.172(e). One commenter stated that the safety net comparison of values is absolutely essential for the protection of the Indian lessor and for the validation of the published index price ranges. Twelve commenters strenuously object to inclusion of a ''safety net'' for the following reasons:

(1) The index-based formula will yield a value that is far in excess of market value. This formula price should satisfy the gross proceeds and major portion clauses of an Indian lease without any need for a ''safety net'' on nondedicated sales.

(2) The safety net provision, to tie value to markets downstream of an index point, implies a duty to market even further from the field or area.

(3) The concept of a safety net was not raised until many months after the vote on the formula had been taken.

(4) The certainty, simplicity, and any administrative benefits gained from the use of the index-based valuation formula are negated with the safety net.

(5) The safety net provision would require tracing gas, and would inevitably lead to a continuation of the current cycle of endless audit disputes and litigation with regard to gas valuation on Indian leases.

Response. The comment that the idea of a safety net was not raised until many months after the vote on the index-based formula was taken is inaccurate. As discussed above, a review of the Committee's meeting minutes for April 1995 indicates that the concept of some type of safety net was part of the original valuation proposal from the Indian representatives and part of the original draft of the index-based formula. The safety net was conceived as a comparison of the index-based value to some other value that would represent the actual proceeds accruing to the lessee. In June 1995, the Committee voted on and adopted the index-based formula. The safety net provision, although part of the proposal, had not yet been discussed in detail by the Committee. A subgroup composed of industry, Indian, and Federal representatives was formed in July 1995 to explore the safety net issue. The Committee continued to periodically discuss the safety net issue over the next year and voted in October 1995 to include a safety net in the proposed rule and finally adopted the language that is contained in the proposed rule in May 1996.

The safety net, by comparing index prices to prices that reflect sales made beyond an index point, ensures that the index-based value represents the value of all market transactions. The safety net is calculated using prices received for gas sold downstream of the index point. The lessee includes only sales under those contracts that establish a delivery point beyond the first index-pricing point to which the gas flows. It includes only the lessee's or its affiliate's sales prices, and it does not require detailed calculations for the costs of transportation. The safety net price captures the significantly higher values for sales occurring beyond the index point. Although the safety net requires tracing the gas beyond the index-pricing point, confidentiality should not be an issue because only the lessee's and its affiliate's sales prices are used in the volume weighted average calculation. MMS has added ''or your affiliate's'' at § 206.172(e)(3) to make it clear it is either the lessee's or its affiliate's arm's-length sales contract that is used in the safety net.

MMS has only 1 year from the date the lessee's safety net prices on Form MMS–4411, Safety Net Report, are due to order the lessee to amend its safety net price calculation. If MMS does not order any adjustment, then the safety net price is final. This provides certainty to the lessee and alleviates extended audit disputes. MMS has determined that the safety net is necessary to ensure that Indian lessors receive royalties on the proper value of production as discussed above.

MMS has added at § 206.172(e)(4)(i) that 80 percent of the safety net value minus 125 percent of the index formula value is the safety net differential.

MMS has revised § 206.172(e)(4)(ii) to clarify that additional royalty is due if the safety net differential under § 206.172(e)(4)(i) is a positive number. The proposed rule did not include a multiplication by any lease royalty rates. In the final rule, paragraph (e)(5)(i) identifies the Indian leases which had production that was sold beyond the index-pricing point and multiplies the production by the safety net differential and by the royalty rate in the lease. Paragraph (e)(5)(ii) describes how you allocate production to Indian leases when production has been commingled with non-Indian production and then sold beyond the first index pricing point.

Comment on § 206.173. Nine commenters supported the use of the alternative methodology for dual accounting, if its use is optional. Two commenters stated that § 206.173(a)(2)(iii) of this title is grammatically incorrect and should be revised to read: ''When you elect to use the alternative methodology for a designated area, you must also use the alternative methodology for any new wells commenced and any new leases acquired in the designated area during the term of the election.''

Response. We agree with the comment and made the suggested wording change to § 206.173(a)(2)(iii) in the final rule.

Also, § 206.173(b)(4) is modified to read ''if any of your gas from the lease is processed during a month'' instead of ''if you process any gas from the lease'' to make it clear that dual accounting is required for all lease production if any of your production is processed, not just for the gas production you process from your Indian lease.

The last sentence of § 206.174(a)(1) was changed to make it clear that a separate major portion calculation other than the index value is not required for leases in an index zone with dedicated contracts.

Comment on § 206.174(a)(4)(ii)—now 206.174(a)(4)(iii). Five commenters suggested that MMS include in the final rule a process by which industry may contest MMS's major portion calculation. These same commenters recommended insertion of the phrase ''less applicable allowances'' after the phrase ''Form MMS–2014'' in the first sentence to clarify that allowances will be deducted before the major portion price is calculated.

Response. A lessee or Indian lessor may appeal the major portion value under 30 CFR part 290. MMS will calculate the major portion value using values from Form MMS–2014, Report of Sales and Royalty Remittance, which have been reduced by applicable transportation allowances. MMS does not agree that the suggested wording change is clarifying or necessary.

Comment on § 206.174(g)(2). One commenter suggested that the final rule require that the minimum value for gas plant products be based on the highest price, or at the very least, the average of the highest prices found in commercial price bulletins. Twelve commenters believe that the ''minimum value'' for gas plant products would effectively establish a dual accounting requirement for liquids values within the dual accounting calculation, and a major portion requirement on liquids within the major portion calculation, neither of which is required or even suggested by the lease terms. These same twelve commenters believed that the index-based formula would satisfy the gross proceeds and major portion requirements for the entire gas stream. One commenter stated that prices published in one of the publications MMS suggested are not available until 90 days after production. This would make timely reporting of gas plant product values impossible. Twelve commenters responded to MMS's request for comments on several specific issues as follows:

- Is a minimum value needed when a lessee chooses the actual dual accounting methodology?

Comment. No. It was demonstrated during the review of the percentage dual accounting alternative that liquid valuation was not a significant factor in the calculation.

- Are there other better methods to use?

Comment. No. No method is preferable to any other because the concept of a minimum value for gas plant products is objectionable.

- Are Conway and Mont Belvieu the proper locations to look for prices for gas plant products?

Comment. Eleven commenters stated that the proper location to look for gas plant products values is the point at which the products are sold. This would be consistent with the lease language which refers to the field or area. One commenter stated that if MMS is looking for some form of gas plant liquid postings, then it should look to the locations of those postings.

- Are the 7.0 and 8.0 cents per gallon the right deductions for transportation and fractionation?

Comment. Eleven commenters found this question irrelevant because the entire concept is objectionable. One commenter stated that the deductions appear reasonable for Conway and Mount Belvieu price postings.

- Would a percentage of the price or actual rates paid be a better deduction?

Comment. Eleven commenters found this question irrelevant because the entire concept is objectionable. One commenter stated that a percentage might provide more certainty but that may be difficult to develop because of price fluctuations.

Response. The Indian lease terms require that ''value'' be calculated based on the highest price paid or offered for the major portion of oil, gas, and all other hydrocarbon substances produced and sold from the field. To ensure that Indian lessors receive the maximum revenues from mineral resources on their land consistent with the Secretary's trust responsibility and lease terms, MMS is adopting a minimum value for gas plant products in the final rule. We have researched the problem with the availability of published price data and determined that the necessary pricing data are available within a week after the end of the month. We appreciate the comments received in response to the specific issues and because no viable alternatives were suggested we will not make any changes in the final rule.

Non-Binding Guidance Under § 206.174(f)

The rule provides that lessees can request and MMS can provide non-binding valuation guidance. MMS cannot issue binding guidance regarding valuation. If a lessee seeks binding guidance, it must ask the Assistant Secretary.

Comment on § 206.174(l)(1). Seven commenters stated that audit closure should not just be limited to leases in Montana and North Dakota. The same commenters also recommend deleting the requirement to report adjustments that would result in additional royalty.

Response. MMS has determined that lessees must make adjustments sooner, and MMS must complete audits sooner for leases in Montana and North Dakota. 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. The Committee discussed what would happen if an area such as the San Juan Basin were disqualified as an index area, and agreed that time limitations would not be appropriate in that case. Naming Montana and North Dakota was the most straightforward way to write the rule. Otherwise, we would need to discuss what happens if an area such as the San Juan Basin becomes disqualified as an index area. We did not make any changes in the final rule.

Comment on § 206.174(l)(1)(ii). Two commenters suggested that to conform to parallel language in paragraph (l)(1)(i), the closing language of the last sentence should be amended to read, ''after the last day of the 12th month *following* the last day to report adjustments.''

Response. We agree and made the change in the final rule.

Comment on § 206.174(l)(2)(i). Two commenters suggested amending the opening phrase of this paragraph to read, ''If you have a pending dispute with your purchaser *that affects valuation.* * * *'' These commenters feel that MMS might otherwise unnecessarily try to avoid audit closure.

Response. MMS agrees and we made the change in the final rule.

Comment on § 206.174(l)(2)(i). Two commenters suggested amending the opening phrase of this paragraph to read, ''If you have a pending *dispute that affects valuation* with the person transporting. * * *''

Response. MMS agrees and we made the change in the final rule. We also consolidated paragraphs (i) and (ii) in the final rule and adjusted the numbering accordingly.

Comment on § 206.174(l)(2)(ii). Two commenters suggested that this provision should be modified to read, ''If there is a written agreement between you and MMS or its delegee *to extend the time limit,* the time period is extended * * *.''

Response. We made the proposed change in the final rule.

Comment on § 206.176(a)(1)(i) and (ii). Five commenters recommended replacing the word ''*including* * * * applicable allowances'' with the word ''less'' to avoid the implication that allowances are not deductible.

Response. We agree and made the suggested word change where appropriate in the final rule.

Comment on § 206.176(c). Eight commenters stated that the Committee agreed that the gas must be traced to the mainline. Whether the pipeline has an index is irrelevant and in any case does not take into account valuation in nonindex areas. This reference should also be corrected in § 206.172(b)(1)(ii) and wherever discussed in the preamble.

Response. We generally agree with the commenters and note that although the Committee spent considerable time trying to determine the correct wording, no decision was ever reached. We changed the wording of the first sentence in § 206.176(c) of the final rule by adding the phrase ''* * * or into a *mainline pipeline* not in an index zone.'' We did not change the wording in § 206.172(b)(1)(ii) for the reasons discussed above. We did not define mainline but intend it to have the same characteristics as a pipeline in an index zone with an index. We have also added wording clarifying that accounting for comparison is not required if the gas produced from the lease is not processed.

Comment on § 206.176(e). Two commenters believe there is no need to compute the weighted average Btu when the alternative method is not being used. This paragraph need only state that you do not have to perform dual accounting for a facility measurement point with a Btu content of less than 1,000 Btu/cf. Likewise, the cross-reference to § 206.173 is not necessary.

Response. We believe that the cross-reference adds clarity, and we did not make the change in the final rule.

Comment on § 206.178(a)(1)(i). One commenter stated that transportation contracts, invoices, or non-arm's-length transportation cost documentation should be made available only upon audit and review. One commenter supported the routine submittal of transportation contracts because the information contained in those contracts will permit the timely verification of the deduction and satisfies the Committee's goal related to closure.

Response. MMS agrees with the need to routinely submit transportation contracts, and we did not make any changes in the final rule.

Comment on § 206.178(f). Two commenters stated that the first sentence of this paragraph should specify that ''you are required to report and pay additional royalties *on the difference,* plus interest * * *.''

Response. We do not believe that the additional wording is necessary and did not make any changes in the final rule.

Comment on § 206.178(g). Seven commenters recommended that the exception for Federal Energy Regulatory Commission (FERC) or State-approved tariffs contained in the regulations published in 1988 be reinstated in the final rule.

Response. We will allow the lessee to deduct only those costs associated with specifically identifiable actual or theoretical losses that are part of the lessee's arm's-length transportation contract. We did not make any change in the final rule.

Comment on § 206.179. One commenter agreed that MMS should not allow extraordinary cost deductions. Two commenters believe that the provisions in the 1988 regulations covering extraordinary processing allowances should be reinstated in the rule.

Response. MMS believes at this time that it is a better exercise of the Secretary's trust responsibility to not allow extraordinary cost allowances for Indian leases.

Comment on § 206.179(f). Two commenters believe that this paragraph is out of place. It should be moved to § 220.550(d) and should include unprocessed gas as well as residue gas and gas plant products.

Response. We assume that the commenters made a typographic error and the correct cite should be § 202.550(d). We do not believe that moving the paragraph will add to or clarify the rule. No change was made in the final rule.

FERC Order 636 Changes. On December 16, 1997, MMS issued a final regulation amending the existing transportation allowance regulation for both Federal and Indian leases (62 FR 65753). These changes result from FERC Order 636.

Many of the transportation allowance provisions changed in that rulemaking were the same as those proposed in this rulemaking. Therefore, this final rule incorporates changes to the transportation allowance rules in §§ 206.177 and 206.178 resulting from the recent final rule.

Paperwork Reduction Act

MMS requested comments on two new forms, Form MMS–4410, Certification for Not Performing Accounting for Comparison (Dual Accounting), and Form MMS–4411, Safety Net Report, as they relate to the Paperwork Reduction Act.

Comment on the Paperwork Reduction Act. Eleven commenters believe that Form MMS–4410 is unnecessary because the same result can be more efficiently accomplished through the use of a specific transaction code on Form MMS–2014. These same commenters stated that because they are totally opposed to the entire ''safety net'' concept, Form MMS–4411 is not needed. The eleven commenters also believe that MMS's estimate of additional costs to the entire industry of only $935,000 per year is absurdly low.

Response. Form MMS–4410 will ensure that the lessee is not in violation of lease terms specifying dual accounting by verifying whether or not dual accounting is required. The form will benefit industry because, by submitting the form, the lessee will not have to perform dual accounting. Further, the form is only a one time certification, which will require less burden than using a reporting code on Form MMS–2014 that would have to be used for every report month. Form MMS–4411 is critical in using the index pricing method to satisfy the gross proceeds and major portion requirements of Indian leases. The form is necessary to ensure that index pricing represents market value and that the tribes do not suffer significant revenue losses. The commenters' statement that the $935,000 estimate is too low was not supported with any verifying data of what the estimate should be. MMS performed an analysis to determine this estimate, as explained in the September 23, 1996, proposed rule, and maintains that this estimate is reasonable.

III. Principal Changes between the Proposed Rule and the Final Rule

Addition of § 206.172(f) and (g). The final rule adds additional paragraphs (f) and (g) to § 206.172. Paragraph (f) permits an Indian tribe to request that some or all of its leases be excluded from valuation under § 206.172. If MMS, after consultation with the Bureau of Indian Affairs (BIA), approves the request, value is determined under § 206.174 beginning with production on the first day of the second month following the date MMS publishes notice in the **Federal Register**. If the tribe requests to exclude only some of its leases, the request will only be approved if the leases may be segregated into one or more groups based on fields within the reservation.

This change is included in the final rule because a revenue analysis indicated the Jicarilla Apache Tribe would receive less revenue under the index methodology than under a gross proceeds methodology. Specifically, royalties reported to MMS on MMS's Form MMS–2014 for 1995 and 1996 exceeded the calculated values using the index formula in § 206.172. The proposed rule provided for MMS to disqualify an index zone, but not to disqualify a reservation within an index zone.

A tribe may also ask MMS to terminate this exclusion. If MMS, after consultation with the BIA, terminates the exclusion, value would be determined under § 206.172. Termination of an exclusion cannot take effect earlier than 1 year after the first day of the production month that the exclusion was effective.

Paragraph (g) for Indian allotted leases contains provisions similar to paragraph (f) and provides that MMS, with BIA consultation, may exclude any allotted leases from valuation under § 206.172.

Addition of § 206.174(a)(4)(iv). A new paragraph (iv) in § 206.174(a)(4) permits using data other than values reported on Form MMS–2014 in calculating the major portion value. The alternative data would be data for production in the designated area reported to a State tax authority or price data from leases MMS has reviewed in the designated area. This change was needed because the revenue analysis indicated that some Indian leases in Oklahoma would receive less revenue under the index methodology than under a gross proceeds methodology and we therefore expect that several tribes in Oklahoma will request their leases to be excluded from index valuation. Indian gas production is only about 2 percent of production in Oklahoma. Since this amount of gas is too small to be representative of all gas production values in a designated area, we needed an additional data source beyond information on a Form MMS–2014. The revenue analysis for the Jicarilla Apache reservation showed similar results and under § 206.172(f), and MMS expects the Jicarilla Apache will request its leases to be excluded from index valuation.

IV. Procedural Matters

Your Comments Are Important

The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions in this final rule, call 1–888–734–3247.

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.*).

Approximately 700 entities pay royalties to MMS on production from Indian lands, 400 of which are small businesses because they employ 500 or less employees. This rule will not have a significant administrative impact on these small entities because it decreases rather than increases the reporting burden. The reduced reporting results from using the alternative method for dual accounting and the relief from complying with major portion requirements under index pricing. For example, the average Indian royalty payor will expend approximately $8,500 less annually for administrative costs to comply with this amended rule than under existing regulations. We estimate that the 200 smallest companies (0–4 employees) would have an average administrative savings of $700 per year.

The rule would also have a royalty impact on small businesses due to the index pricing formula for index-based areas and the major portion provision for non-index areas. We estimate that 35 percent of the total gas royalties paid on Indian tribal lands derive from the 400 small businesses that pay Indian gas royalties.

In our cost benefit analysis of the rule's impact, we estimated that the index pricing formula would increase Indian revenues by about $ 2.4 million annually. Therefore, small businesses would incur an annual increase of about $2,100 per company ($2,400,000 x .35 ÷ 400). This represents about a 5 percent increase in royalties, so a very small company (e.g., 0–4 employees) that pays, for example, only $500 per year in royalties would pay approximately an additional $25.

In non-index areas, we estimate that the major portion provisions of the new rule would increase Indian revenues by $57,000 annually. Small businesses on average would account for about $50 each ($57,000 × .35 ÷ 400). However, given the significant administrative savings of the rule described above, we believe any increase in royalties paid by small companies will be more than offset by savings in reporting burdens.

Likewise, this rule will not adversely impact small tribal governments. This rule will increase annual royalty revenues to tribal governments by approximately $2.5 million.

Unfunded Mandates Reform Act of 1995

This Department has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1531 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on local, tribal, State governments, or the private sector.

Executive Order 12630

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

Executive Order 12988

The Department has certified to the Office of Management and Budget that this rule meets the applicable 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. MMS estimates that this rule will result in an overall $7.4 million administrative cost savings to industry.

Paperwork Reduction Act

This final rule contains information collection requirements. These requirements have been approved by the Office of Management and Budget (OMB) and assigned OMB Control Numbers 1010–0075.

As discussed below, this final rule impacts an existing collection of information on Forms MMS–4109 and MMS–4295, which has 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 Publications Staff, PO Box 25165, MS 3021, Denver, Colorado 80225–0165; courier address is: Building 85, Denver Federal Center, Denver, Colorado 80225; e-Mail address is: RMP.comments@mms.gov.

As a predecessor to this rulemaking, on September 23, 1996, MMS published in the **Federal Register** a Notice of Proposed Rulemaking (NPR) (61 FR 49894) to amend its regulations governing the valuation for royalty purposes of natural gas produced from Indian leases. The NPR introduced two new forms—Form MMS–4410, Certification for Not Performing Accounting for Comparison (Dual Accounting) (OMB Control Number 1010–0104), and Form MMS–4411, Safety Net Report (OMB Control Number 1010–0103). These forms were approved by OMB on November 5, 1996. Forms MMS–4295 and 4109 were also mentioned in this NPR. No comments were received from the public on these allowance forms.

OMB may make a decision to approve or disapprove this collection of information after 30 days from receipt of our request. Therefore, your comments are best assured of being considered by OMB if OMB receives them within that time period. However, MMS will consider all comments received to determine if a further rulemaking is necessary.

The burden hours associated with the existing information collection titled Gas Processing Allowance Summary Report (Form MMS–4109) and Gas Transportation Allowance Report (Form MMS–4295), OMB Control Number 1010–0075, will be reduced by this final rulemaking. Instead of submitting estimated processing or transportation cost information on the forms and then following up with actual cost information at the end of the reporting cycle, the rule will require only responses with actual cost information. In addition, Indian lessees that have arm's-length transportation and processing contracts will submit copies of the actual contracts to MMS.

MMS estimates that 65 Indian lessees will submit approximately 3,000 allowance data lines annually. Lessees may be involved in more than one type of allowance proposal and may submit both a processing allowance line and a transportation allowance line. Based on past experience, MMS estimates that lessees can complete an allowance data line in about ¼ hour.

The estimate of the total annual burden hours to respondents for this information collection is 750 hours (3,000 allowance data lines × ¼ hour). The Gas Transportation Allowance Report, Form MMS–4295, accounts for approximately 2,400 responses annually (80 percent of the forms received), and the Gas Processing Allowance Summary Report, Form MMS–4109, accounts for approximately 600 responses annually (20 percent of the forms received). Therefore, the annual estimate of the burden hours by form is 600 hours for Form MMS–4295 and 150 hours for Form MMS–4109.

The MMS estimates that this information collection will result in a decrease to industry of about 2,755 burden hours annually. The MMS attributes this decrease primarily to the decrease in the number of responses to only actual cost information as discussed above. A further decrease will result from certain lessees electing the alternative method for valuing processed gas, which requires no processing allowance to be taken and no accompanying allowance report to be submitted.

In compliance with the Paperwork Reduction Act of 1995, Section 3506 (c)(2)(A), we are notifying you, members of the public and affected agencies, of this collection of information, and are inviting your comments. For instance your comments may address the following areas. Is this information collection necessary for us to properly do our job? Have we accurately estimated the industry burden for responding to this collection? Can we enhance the quality, utility, and clarity of the information we collect? Can we lessen the burden of this information collection on the respondents by using 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 determined that this rulemaking is not a major Federal action significantly affecting the quality of the human environment, and a detailed statement under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) is not required.

List of Subjects

30 CFR Part 202

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

30 CFR Part 206

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

Dated: March 23, 1999.

Sylvia V. Baca,

Assistant Secretary—Land and Minerals Management.

For the reasons set out in the preamble, 30 CFR parts 202 and 206 are 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.*

§ 202.51 [Amended]

2. Paragraph (b) of § 202.51 is revised to read as follows:

* * * * *

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

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

Subpart D—Federal Gas

§ 202.150 [Amended]

4. In § 202.150 the words ''or Indian'' are removed from. (b)(1), (e)(1) and (e)(2).

§ 202.150 [Amended]

5. In § 202.150 the words ''and Indian'' and ''or Indian'' are removed from paragraph (f).

§ 202.151 [Amended]

6. In § 202.151, the words ''and Indian'' are removed from paragraph (a)(2).

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

Subpart J—Gas Production from Indian Leases

Subpart J— Gas Production From Indian Leases

§ 202.550 How do I determine the royalty due on gas production?

If you produce gas from an Indian lease subject to this subpart, you must determine and pay royalties on gas production as specified in this section.

(a) *Royalty rate.* You must calculate your royalty using the royalty rate in the lease.

(b) *Payment in value or in kind.* You must pay royalty in value unless:

(1) The Tribal lessor requires payment in kind; or

(2) You have a lease on allotted lands and MMS requires payment in kind.

(c) *Royalty calculation.* You must use the following calculations to determine royalty due on the production from or attributable to your lease.

(1) When paid in value, the royalty due is the unit value of production for royalty purposes, determined under 30 CFR part 206, multiplied by the volume of production multiplied by the royalty rate in the lease.

(2) When paid in kind, the royalty due is the volume of production multiplied by the royalty rate.

(d) *Reduced royalty rate.* The Indian lessor and the Secretary may approve a request for a royalty rate reduction. In your request you must demonstrate economic hardship.

(e) *Reporting and paying.* You must report and pay royalties as provided in part 218 of this title.

§ 202.551 How do I determine the volume of production for which I must pay royalty if my lease is not in an approved Federal unit or communitization agreement (AFA)?

(a) You are liable for royalty on your entitled share of gas production from your Indian lease, except as provided in §§ 202.555, 202.556, and 202.557.

(b) You and all other persons paying royalties on the lease must report and pay royalties based on your takes. If another person takes some of your entitled share but does not pay the royalties owed, you are liable for those royalties.

(c) You and all other persons paying royalties on the lease may ask MMS for permission to report and pay royalties based on your entitlements. In that event, MMS will provide valuation instructions consistent with this part and part 206 of this title.

§ 202.552 How do I determine how much royalty I must pay if my lease is in an approved Federal unit or communitization agreement (AFA)?

You must pay royalties each month on production allocated to your lease under the terms of an AFA. To determine the volume and the value of your production, you must follow these three steps:

(a) You must determine the volume of your entitled share of production allocated to your lease under the terms of an AFA. This may include production from more than one AFA.

(b) You must value the production you take using 30 CFR part 206. If you take more than your entitled share of production, see § 202.553 for information on how to value this production. If you take less than your entitled share of production, see § 202.554 for information on how to value production you are entitled to but do not take.

§ 202.553 How do I value my production if I take more than my entitled share?

If you take more than your entitled share of production from a lease in an AFA for any month, you must determine the weighted-average value of all of the production that you take using the procedures in 30 CFR part 206, and use that value for your entitled share of production.

§ 202.554 How do I value my production that I do not take if I take less than my entitled share?

If you take none or only part of your entitled production from a lease in an AFA for any month, use this section to value the production that you are entitled to but do not take.

(a) If you take a significant volume of production from your lease during the month, you must determine the weighted average value of the production that you take using 30 CFR part 206, and use that value for the production that you do not take.

(b) If you do not take a significant volume of production from your lease during the month, you must use paragraph (c) or (d) of this section, whichever applies.

(c) In a month where you do not take production or take an insignificant volume, and if you would have used § 206.172(b) to value the production if you had taken it, you must determine the value of production not taken for that month under § 206.172(b) as if you had taken it.

(d) If you take none of your entitled share of production from a lease in an AFA, and if that production cannot be valued under § 206.172(b), then you must determine the value of the production that you do not take using the first of the following methods that applies:

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

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

(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.

(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.

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

(e) You may take less than your entitled share of AFA production for any month, but pay royalties on the full volume of your entitled share under this section. If you do, 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. The provisions of this paragraph (e) also apply when the other AFA participants pay you money to balance your account.

§ 202.555 What portion of the gas that I produce is subject to royalty?

(a) All gas produced from or allocated to your Indian lease is subject to royalty except the following:

(1) Gas that is unavoidably lost.

(2) Gas that is used on, or for the benefit of, the lease.

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

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

(b) 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 for one of the following purposes:

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

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

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

§ 202.556 How do I determine the value of avoidably lost, wasted, or drained gas?

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 under 30 CFR part 206.

§ 202.557 Must I pay royalty on insurance compensation for unavoidably lost gas?

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.

§ 202.558 What standards do I use to report and pay royalties on gas?

(a) You must report gas volumes as follows:

(1) Report gas volumes and Btu heating values, if applicable, under the same degree of water saturation. Report gas volumes and Btu heating value at a standard pressure base of 14.73 psia and a standard temperature of 60 degrees Fahrenheit. Report gas volumes in units of 1,000 cubic feet (Mcf).

(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) You must report residue gas and gas plant product volumes as follows:

(1) 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) Report natural gas liquid (NGL) volumes in standard U.S. gallons (231 cubic inches) at 60 degrees F.

(3) Report sulfur (S) volumes in long tons (2,240 pounds).

PART 206—PRODUCT VALUATION

8. The authority citation for 30 CFR 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 does this subpart contain?

This subpart contains 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 on Indian allotted lands, 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 What definitions apply to this subpart?

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 departmental regulations.

Area means a geographic region at least as large as the defined limits of an oil or gas field, in which oil or gas lease products have similar quality, economic, or legal characteristics. An area may be 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. The following percentages (based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership) determine if persons are affiliated:

(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 under 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. However, it does not include residue gas.

Gathering means the movement of lease production to a central accumulation 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, 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)(2).

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 (including operating rights owners) 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.

Marketable condition means a condition in which lease products are sufficiently free from impurities and otherwise so conditioned 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 of 1982, 30 U.S.C. 1701 *et seq.* or other applicable agreements.

Minimum royalty means that minimum amount of annual royalty that the lessee must pay 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, or heavier liquid hydrocarbons.

Net-back method (or *work-back method*) means a method for calculating market value of gas at the lease under which costs of transportation, processing, and 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 (or *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.

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, desulphurization (or "sweetening"), 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 do I value gas produced from leases in an index zone?

(a) *What leases this section applies to.* 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.

(1) You must use the valuation provision of this section if your lease is in an index zone and meets one of the following two requirements:

(i) Has a major portion provision;

(ii) Does not have a major portion provision, but 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, you must determine the value of these products under § 206.174.

(b) *Valuing residue gas and gas before processing.* (1) Except as provided in paragraphs (e), (f), and (g) of this section, this paragraph (b) explains how you must value the following four types of gas:

(i) Gas production before processing;

(ii) Gas production that you certify on Form MMS–4410, Certification for Not Performing Accounting for Comparison (Dual Accounting), is not processed before it flows into a pipeline with an index but which may be processed later;

(iii) Residue gas after processing; and

(iv) Gas that is never processed.

(2) The value of gas production that is not sold under an arm's-length dedicated contract is the index-based value determined under paragraph (d) of this section unless the gas was subject to a previous contract which was part of a gas contract settlement. If the previous contract was subject to a gas contract settlement and if the royalty-bearing contract settlement proceeds per MMBtu added to the 80 percent of the safety net prices calculated at § 206.172(e)(4)(i) exceeds the index-based value that applies to the gas under this section (including any adjustments required under § 206.176), then the value of the gas is the higher of the value determined under this section (including any adjustments required under § 206.176) or § 206.174.

(3) The value of gas production that is sold under an arm's-length dedicated contract is the higher of the index-based value under paragraph (d) of this section or the value of that production determined under § 206.174(b).

(c) *Valuing gas that is processed before it flows into a pipeline with an index.* Except as provided in paragraphs (e), (f), and (g) 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 this gas production based on the higher of the following two values:

(1) The value of the gas before processing determined under paragraph (b) of this section.

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

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

(ii) The value of the gas plant products determined under § 206.174, less any applicable processing and/or transportation 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) *Determining 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 use the following procedures:

(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; and

(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 five 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's 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 the following five criteria:

(i) Publications buyers and sellers frequently use;

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

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

(iv) Publications that 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.

(e) *Determining the minimum value for royalty purposes of gas sold beyond the first index pricing point.* (1) Notwithstanding any other provision of this section, the value for royalty purposes of gas production from an Indian lease that is sold beyond the first index pricing point through which it flows 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 (S) for an index zone is the volume-weighted average contract price per delivered MMBtu under your or your affiliate's arm's-length contracts for the disposition of residue gas or unprocessed gas produced from your Indian leases in that index zone as computed under this paragraph (e)(3).

(i) Include in your calculation only sales under those contracts that establish a delivery point beyond the first index pricing point through which the gas flows, and that include any gas produced from or allocable to one or more of your Indian leases in that index zone, even if the contract also includes gas produced from Federal, State, or fee properties. Include in your volume-weighted average calculation those volumes that are allocable to your Indian leases in that index zone.

(ii) Do not reduce the contract price for any transportation costs incurred to deliver the gas to the purchaser.

(iii) For purposes of this paragraph (e), the contract price will not include the following amounts:

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

(B) Deductions for you or any other person to put gas production into marketable condition or to market the gas; and

(C) Any amounts related to marketable securities associated with the sales contract.

(4) Next, you must determine for each month the safety net differential (SND). You must perform this calculation separately for each index zone.

(i) For each index zone, the safety net differential is equal to: $SND = [(0.80 \times S) - (1.25 \times I)]$ where (I) is the index-based value determined under 30 CFR 206.172(d).

(ii) If the safety net differential is positive you owe additional royalties.

(5)(i) To calculate the additional royalties you owe, make the following calculation for each of your Indian leases in that index zone that produced gas 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) of this section:

Lease royalties owed = $SND \times V \times R$, where R = the lease royalty rate and V = the volume allocable to the lease which produced gas that was sold beyond the first index pricing point.

(ii) If gas produced from any of your Indian leases is commingled or pooled with gas produced from non-Indian properties, and if any of the combined gas is sold at a delivery point beyond the first index pricing point through which the gas flows, then the volume allocable to each Indian lease for which gas was sold beyond the first index pricing point in the calculation under paragraph (e)(5)(i) of this section is the volume produced from the lease multiplied by the proportion that the total volume of gas sold beyond the first index pricing point bears to the total volume of gas commingled or pooled from all properties.

(iii) Add the numbers calculated for each lease under paragraph (e)(5)(i) of this section. The total is the additional royalty you owe.

(6) 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, Safety Net Report, 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; and

(iii) MMS may order you to amend your safety net price within one year from the date your Form MMS–4411 is due or is filed, whichever is later. If MMS does not order any amendments within that one-year period, your safety net price calculation is final.

(f) *Excluding some or all tribal leases from valuation under this section.* (1) An Indian tribe may ask MMS to exclude some or all of its leases from valuation under this section. MMS will consult with BIA regarding the request.

(i) If MMS approves the request for your lease, you must value your production under § 206.174 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the **Federal Register**.

(ii) If an Indian tribe requests exclusion from an index zone for less than all of its leases, MMS will approve the request only if the excluded leases may be segregated into one or more groups based on separate fields within the reservation.

(2) An Indian tribe may ask MMS to terminate exclusion of its leases from valuation under this section. MMS will consult with BIA regarding the request.

(i) If MMS approves the request, you must value your production under § 206.172 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the **Federal Register**.

(ii) Termination of an exclusion under paragraph (f)(2)(i) of this section cannot take effect earlier than 1 year after the first day of the production month that the exclusion was effective.

(3) The Indian tribe's request to MMS under either paragraph (f)(1) or (2) of this section must be in the form of a tribal resolution.

(g) *Excluding Indian allotted leases from valuation under this section.* (1)(i) MMS may exclude any Indian allotted leases from valuation under this section. MMS will consult with BIA regarding the exclusion.

(ii) If MMS excludes your lease, you must value your production under § 206.174 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the **Federal Register**.

(iii) If MMS excludes any Indian allotted leases under this paragraph (g)(1), it will exclude all Indian allotted leases in the same field.

(2)(i) MMS may terminate the exclusion of any Indian allotted leases from valuation under this section. MMS will consult with BIA regarding the termination.

(ii) If MMS terminates the exclusion, you must value your production under § 206.172 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the **Federal Register**.

§ 206.173 How do I calculate the alternative methodology for dual accounting?

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

(2) You must make a separate election to use the alternative methodology for dual accounting 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.

(i) MMS will publish in the **Federal Register** a list of the lease prefixes that will be associated with each designated area for purposes of this section. The MMS-designated areas are as follows:

(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 for a designated area, you must also use the alternative methodology for any new wells commenced and any new leases acquired in the designated area during the term of the election.

(b) *Calculating value using the alternative methodology for dual accounting.* (1) The alternative methodology adjusts the value of gas before processing determined under either § 206.172 or § 206.174 to provide the value of the gas after processing. You must use the value of the gas after processing 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, as provided in the table in paragraph (b)(2)(ii) of this section. If you have a direct or indirect ownership interest in the plant where the gas is processed, the increase is higher, as provided in paragraph (b)(2)(ii) of this section.

(2) To calculate the value of the gas after processing using the alternative methodology for dual accounting, you must apply the increase to the value before processing, determined in either § 206.172 or § 206.174, as follows:

(i) Value of gas after processing = (value determined under either § 206.172 or § 206.174, as applicable) × (1 + increment for dual accounting); and

(ii) In this equation, the increment for dual accounting is the number you take from the applicable Btu range, determined under paragraph (b)(3) of this section, 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
1701+	.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 any of your gas from the lease is processed during a month, use the following two paragraphs to determine which amounts are subject to dual accounting and which dual accounting method you must use.

(i) Weighted-average Btu content determined under paragraph (b)(3) of this section is 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 if you elected to use the alternative method under this section.

(ii) Weighted-average Btu content determined under paragraph (b)(3) of this section is 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 are 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 do I value gas production when an index-based method cannot be used?

(a) *Situations in which an index-based method cannot be used.* (1) Gas production must be valued under this section in the following situations.

(i) Your lease is not in an index zone (or MMS has excluded your lease from an index zone).

(ii) If your lease is in an index zone and you sell your gas under an arm's-length dedicated contract, then the value of your gas is the higher of the value received under the dedicated contract determined under § 206.174(b) or the value under § 206.172.

(iii) Also use this section to value any other gas production that cannot be valued under § 206.172, as well as gas plant products, and to value components of the gas stream that have no Btu value (for example, carbon dioxide, nitrogen, etc.).

(2) The value for royalty purposes of gas production 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.

(4) 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.

(i) The value of production you must initially report and pay is the value determined in accordance with the other paragraphs of this section.

(ii) MMS will determine the major portion value and notify you in the **Federal Register** 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 by the due date specified in the 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.

(iii) Except as provided in paragraph (a)(4)(iv) of this section, MMS will calculate the major portion value for each designated area (which are the same designated areas as under § 206.173) 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.

(iv) MMS may calculate the major portion value using different data than the data described in paragraph (a)(4)(iii) of this section or data to augment the data described in paragraph (a)(4)(iii) of this section. This may include price data reported to the State tax authority or price data from leases MMS has reviewed in the designated area. MMS may use this alternate or the augmented data source beginning with production on the first day of the month following the date MMS publishes notice in the **Federal Register** that it is calculating the major portion using a method in this paragraph (a)(4)(iv) of this section.

(b) *Arm's-length contracts.* (1) 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 or your affiliate, except as provided in paragraphs (b)(1)(ii)–(iv) of this section.

(i) 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 or your affiliate 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 or your affiliate, including the additional consideration.

(iii) If MMS determines for gas valued under this paragraph that the gross proceeds accruing to you or your affiliate 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 (3) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your value.

(iv) This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price specified in the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessees must value all over-delivered volumes under paragraph (c)(2) or (3) of this section.

(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) *Non-arm's-length contracts.* 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 of the following three methods:

(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.

(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 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.

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

(d) *Supporting data.* 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.

(1) Such data will be subject to review and audit, and MMS will direct you to use a different value if we determine upon review or audit that the value you reported is inconsistent with the requirements of these regulations.

(2) You must make all such data available upon request to the authorized MMS or Indian representatives, to the Office of the Inspector General of the Department, or other authorized persons. This includes 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) *Improper values.* 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 on how to take that credit.

(f) *Value guidance.* You may ask MMS for guidance in determining value. You may propose a valuation method to MMS. Submit all available data related to your proposal and any additional information MMS deems necessary. MMS will promptly review your proposal and provide you with a non-binding determination of the guidance you request.

(g) *Minimum value of production.* (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 (including its affiliates) 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 as follows:

(i) Leases in certain States and areas have specific minimum values.

(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, Texas, 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, Kansas, 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; and (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) *Marketable condition/Marketing.* You are required to place gas, residue gas, and gas plant products in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. 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 to place the gas, residue gas, or gas plant products in marketable condition or to market the gas, the cost of which ordinarily is your responsibility.

(i) *Highest obtainable price or benefit.* 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) *Non-binding MMS reviews.* 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 against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) *Confidential information.* 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 limits 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 following the last day to report adjustments.

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

(i) If you have a pending dispute with your purchaser or with the person transporting or processing your gas production that affects valuation, the time periods to make adjustments in paragraphs (l)(1)(i) and (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 there is a written agreement between you and MMS or its delegee (if applicable) to extend the time limit, the time period is extended for the period stated in the agreement;

(iii) 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 (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;

(iv) 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; and

(v) The time period in paragraphs (l)(1)(i) and (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 may easily 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 do I 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 if 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 of gas plant products attributable to the lease 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 volumes of residue gas and of gas plant products delivered from all leases by summing the theoretical volumes of residue gas and of gas plant products delivered from each lease; and

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

(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 do I perform accounting for comparison?

(a) This section applies if the gas produced from your Indian lease is processed 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 the following two values:

(1) The combined value of the following products:

(i) The residue gas and gas plant products resulting from processing the gas determined under either § 206.172 or § 206.174, less 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 § 206.52, less applicable allowances.

(2) The value of the gas prior to processing determined under either § 206.172 or § 206.174, 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 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 or into a mainline pipeline not 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 or the alternative dual accounting methodology of § 206.173, 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.

Transportation Allowances

§ 206.177 What general requirements regarding transportation allowances apply to me?

(a) When you value gas under § 206.174 at a point off the lease, unit, or communitized area (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, unit, or communitized area. 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, unit, or communitized area. This would include, if appropriate, transportation from the lease to a gas processing plant off the lease, unit, or communitized area 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.

(c)(1) Except as provided in paragraphs (c)(2) and (3) of this section, your transportation allowance deduction for each selling arrangement may 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, MMS 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. Under no circumstances may an allowance reduce the value for royalty purposes under any selling arrangement to zero.

(3) Your application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination.

(d) If MMS conducts a review 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 do I determine a transportation allowance?

(a) *Determining a transportation allowance under an arm's-length contract.* (1) This paragraph explains how to determine your allowance if you have an arm's-length transportation contract.

(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 (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 (e) 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 of 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) This paragraph explains how to allocate the costs to each product 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.

(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 that the volume of each product (excluding waste products which have no value) bears 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 that 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 we determine that it meets one of the two following requirements:

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

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

(3) This paragraph explains how to allocate costs to each product 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.

(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 price, 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 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) *Determining a transportation allowance under a non-arm's-length or no contract.* (1) This paragraph explains how to determine your allowance if you have a non-arm's-length transportation contract or no contract.

(i) When you have a non-arm's-length transportation contract or no contract, including those situations where you perform transportation services for yourself, 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, Gas Transportation Allowance Report, 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) This paragraph explains what actual transportation costs are allowable under a non-arm's-length contract or no contract situation. 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) that 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 that 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 that 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 that 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 that is determined under paragraph (b)(4) of this section.

(3) This paragraph explains how to allocate transportation costs to each product and transportation system.

(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 in the same proportion that the volume of each product (excluding waste products that have no value) bears to the volume of all products in the gaseous phase (excluding waste products that have no value). Except as provided in this paragraph, you may not take an allowance for transporting a product that 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 it meets one of the two following requirements:

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

(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) *Using the alternative transportation calculation when you have a non-arm's-length or no contract.* (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. Your first election will remain in effect until the end of the succeeding calendar year, except for elections effective January 1 that will be effective only for that calendar year.

(d) *Reporting your transportation allowance.* (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 line item on Form MMS–2014. MMS may approve a different reporting procedure on allottee leases, and with lessor approval on tribal leases.

(e) *Adjusting incorrect allowances.* If for any month the 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 from the first day of the first month you deducted the improper transportation allowance until the date you pay the royalties due. If the 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.

(f) *Determining allowable costs for transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS–2014. You must modify the Form MMS–2014 by the amount received or credited for the affected reporting period.

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC orders in 18 CFR part 284.

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service.

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines.

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs.

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses.

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-

arm's-length transportation arrangements.

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as ''parking'' or ''banking''), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less.

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under § 206.174(h).

(g) *Determining nonallowable costs for transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days.

(2) *Aggregater/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production.

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to the following:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within tolerances.

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline.

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub.

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(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.

Processing Allowances

§ 206.179 What general requirements regarding processing allowances apply to me?

(a) When you value any gas plant product under § 206.174, 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 66 2/3 percent of the value of each gas plant product determined under § 206.174. Before you calculate the 66 2/3 percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under § 206.177.

(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 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 that 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, that is reinjected into a reservoir within the same lease, unit, or approved Federal agreement, until such time as those products are finally produced from the reservoir for sale or other disposition. 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 do I determine an actual processing allowance?

(a) *Determining a processing allowance if you have an arms's-length processing contract.* (1) This paragraph explains how you determine an allowance under an arm's-length processing contract.

(i) The processing allowance is the reasonable actual costs you incur to process the gas under that contract. Paragraphs (a)(1)(ii) and (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 that deducts the allowance on the Form MMS–2014.

(ii) When MMS conducts reviews and audits, we 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 may not take an allowance for the costs of processing lease production that 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 may not take a processing allowance for the costs of processing lease production that is not royalty-bearing.

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

(b) *Determining a processing allowance if you have a non-arm's-length contract or no contract.* (1) This paragraph applies if you have a non-arm's-length processing contract or no contract, including those situations where you perform processing for yourself.

(i) If you have a non-arm's-length contract or no contract, the processing allowance is based upon your reasonable actual costs of processing as provided in paragraph (b)(2) 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, Gas Processing Allowance Summary Report, 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 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) that 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 that 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 that 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 that 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. A processing plant may be depreciated only once, regardless of whether there is a change in ownership. Equipment may not be depreciated below a reasonable salvage value. To compute a return on undepreciated capital investment, you must 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 must 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 may not take an allowance for the costs of processing lease production that is not royalty-bearing.

(c) *Reporting your processing allowance.* (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 line item on the Form MMS–2014. MMS may approve a different reporting procedure for allottee leases, and with lessor approval on tribal leases.

(d) *Adjusting incorrect processing allowances.* If for any month the 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 from the first day of the first month you deducted a processing allowance until the date you pay the royalties due. If the 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.

(e) *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 How do I establish processing costs for dual accounting purposes when I do not process the gas?

Where accounting for comparison (dual accounting) is required for gas production from a lease but neither you nor someone acting on your behalf processes the gas, and you have elected to perform actual dual accounting under § 206.176, you must use the first applicable of the following methods to establish processing costs for dual accounting purposes:

(a) 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.

(b) 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.

(c) 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.

(d) Processing costs based on the regulations in §§ 206.179 and 206.180.

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