consideration will be given to the impact of any action planned.

Regulatory Flexibility Act

In compliance with the Regulatory Flexibility Act (Pub. L. 96–354, 5 U.S.C. 601–612), the FHWA will provide an evaluation of the effects on small entities of any proposed rule developed following receipt of comments from this action.

Executive Order 12612 (Federalism Assessment)

This action has been analyzed in accordance with the principles and criteria contained in Executive Order 12612, and it has been determined that this action does not have sufficient federalism implications to warrant the preparation of a federalism assessment.

Executive Order 12372 (Intergovernmental Review)

Catalog of Federal Domestic Assistance Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to this program.

Paperwork Reduction Act

This action does not contain a collection of information requirement for purposes of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq*.

National Environmental Policy Act

The agency has analyzed this action for the purpose of the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq*.) and has determined that this action would not have any effect on the quality of the environment.

Regulation Identification Number

A regulation identification number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN contained in the heading of this document can be used to cross reference this action with the Unified Agenda.

List of Subjects in 23 CFR Parts 710 Through 740

Grant programs—transportation, Highways and roads, Real property acquisition, Relocation assistance, Rights-of-way.

(23 U.S.C. 101(a), 103, 107, 108, 111, 114, 142(g), 156, 204, 210, 308, 317, 323; 49 U.S.C. 303, 2000, 4633, 4651–4655; 49 CFR 1.48(b), 18, 21 and 24; 23 CFR 1.32)

Issued on: October 27, 1995.

Rodney E. Slater,

Federal Highway Administrator.

[FR Doc. 95–27446 Filed 11–3–95; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 202, 206, and 211

RIN 1010 AC02

Amendments to Gas Valuation Regulations for Federal Leases

AGENCY: Minerals Management Service, Interior.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Minerals Management Service (MMS) is proposing amendments to regulations governing the valuation for royalty purposes of natural gas produced from Federal leases. These changes would add several alternative valuation methods to the existing regulations. The proposed rules represent the consensus decisions reached by MMS' Federal Gas Valuation Negotiated Rulemaking Committee (Committee).

DATES: Comments must be submitted on or before January 5, 1996.

ADDRESSES: Mail written comments, suggestions, or objections regarding the proposed amendment to: Minerals Management Service, Royalty Management Program, Rules and Procedures Staff, P.O. Box 25165, MS 3101, Denver, Colorado, 80225–0165. MMS will publish a separate notice in the Federal Register indicating dates and locations of public hearings regarding this proposed rulemaking.

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

SUPPLEMENTARY INFORMATION: The principal authors of this proposed rule are Lawrence E. Cobb of MMS, John L. Price of MMS, and Peter Schaumberg of the Office of the Solicitor. Members of the Federal Gas Valuation Negotiated Rulemaking Committee also participated in the preparation of this proposed rule.

I. Introduction

On June 2, 1994, the Secretary of the Interior chartered the Committee to advise MMS on a rulemaking to address: (1) The valuation of gas produced from approved Federal unit and communitization agreements (agreements) (particularly when lessees take less than their entitled share of production); and (2) the benchmark valuation system for valuing gas sold under non-arm's-length contracts (59 FR 32944, June 27, 1994). The Committee's scope was limited to examining values for gas produced from Federal leases and its original charter did not include the valuation of gas sold under arm's-length contracts. However, the Committee was faced with a new gas marketing environment which has resulted from deregulation of natural gas production and open access, particularly with the issuance of Federal Energy Regulatory Commission (FERC) Order No. 636 (Order No. 636) (57 FR 13267, April 16, 1992). To simplify valuation for all types of Federal gas sales impacted by today's gas market, MMS concurred with the Committee's recommendation to expand its charter to include the valuation of Federal gas production under both arm's-length and non-arm's-length sales contracts.

Members of the Committee included representatives from the American Petroleum Institute (API), the Council of Petroleum Accountants Societies (COPAS), the Rocky Mountain Oil and Gas Association (RMOGA), the Independent Petroleum Association of America (IPAA)/Independent Petroleum Association of Mountain States (IPAMS), the Natural Gas Supply Association (NGSA), an independent marketer, representatives of large independent producers, MMS, and personnel from the States of Utah, North Dakota, Montana, and New Mexico representing the State and Tribal Royalty Audit Committee (STRAC).

The Committee agreed to operate based on consensus decision making. MMS committed to publish as a proposed rulemaking all consensus decisions. The Committee further agreed that its final report and the resulting proposed rule would not prohibit any Committee member or his/her constituents from commenting on this proposed rule or challenging the final rule, or any order issued under the rule.

The policy of the Department of the Interior is, whenever practicable, to afford the public an opportunity to participate in the rulemaking process. All of the sessions of the Committee were announced in the Federal Register, were open to the public, and provided for an opportunity for public input. In addition, any interested persons may submit written comments, suggestions, or objections regarding this proposed rule to the location identified in the **ADDRESS** section of this preamble.

The rulemaking process has necessarily required that the Committee's consensus be incorporated into the existing regulations as well as in new regulations. In some instances, various participants on the Committee may have longstanding differences of opinion with MMS on the meaning and interpretation of existing regulations, some of which may be under administrative or judicial appeal. The incorporation of the Committee's consensus as expressed in the report into the existing regulatory framework should not be interpreted or infer that consensus was also reached on these differences or that they have been waived or withdrawn.

MMS commends the Committee's ability to compromise and develop a proposal that would simplify royalty payments on natural gas produced from Federal leases, while reducing administrative costs, decreasing litigation costs, and maintaining revenue neutrality.

II. Purpose and Background

In March 1995, the Committee published its final report (''Committee Report''), which summarizes the consensus decisions of the 20-member Committee. This report forms the basis for the proposals in this rulemaking and is an essential part of the regulatory history for this proposed rulemaking. For each recommendation, the report provides background as to why the Committee considered a regulatory change, the alternatives discussed, any related negotiation, the final recommendation, and, if necessary, further explanation of the recommendation, including examples. You may obtain the report by contacting the MMS Valuation and Standards Division at (303) 275–7201 or –7234, or by facsimile at (303) 275–7227.

III. Description of Regulatory Proposals

This proposed rulemaking would accomplish two principal purposes. The first principal purpose is to establish a procedure to value, and to report and pay royalties on, production for operating rights owners of Federal leases that are part of mixed agreements, *i.e.*, Federally-approved agreements that include other than only Federal leases with the same royalty rate and fund distribution. The second principal purpose is to provide lessees with alternative methods to value gas production from Federal leases that would supplement the valuation procedures in the existing regulations in 30 CFR part 206. However, as explained later in this preamble, not all leases would qualify for the alternative valuation methods.

These alternative valuation methods would *not* apply to Indian leases. Therefore, as part of this rulemaking, MMS would have to restructure 30 CFR parts 202 and 206. Basically, the existing provisions of subpart D of parts 202 and 206 currently applicable to both Federal and Indian gas would be retained, but would be applicable only to Indian gas. All references to Federal gas, and those valuation provisions unique to Federal gas, would be removed. In addition, new subparts would be created in both parts 202 and 206 for Federal gas. These new subparts would retain most of the provisions of the existing regulations applicable to Federal gas (of course, with references to Indian gas removed). In addition, these new subparts would include the proposed alternative valuation methods the Committee developed, including simplified procedures to determine applicable transportation allowances.

It should be noted that there is a negotiated rulemaking committee that is considering changes to the procedures for valuing gas production from Indian leases (60 FR 7152, February 7, 1995). However, any regulatory changes resulting from that process would affect only Indian leases and would not directly impact this rulemaking.

A description of the major regulatory changes proposed in this rulemaking as a result of the Committee's recommendations follows:

Part 202

MMS is proposing a new subpart J for 30 CFR part 202 that would be applicable only to Federal gas. MMS correspondingly would amend existing subpart D of part 202 to remove references to Federal gas, but would preserve all the provisions for valuing Indian gas under that subpart.

The new subpart J for Federal gas would retain many of the basic provisions of existing subpart D. Also, based on the Committee's recommendations, several new provisions related to valuing production from, or allocable to, Federal leases in agreements would be included in subpart J.

In new § 202.450(d), MMS is proposing that royalty would be due on the full share of production allocated to a Federal lease under the terms of the agreement at the royalty rate specified in the lease. This would not be a change from the existing rules. The primary proposal is that for each operating rights owner in the lease, royalty would be due on its entitled share of production allocable to the lease based on its percentage ownership. (See the recommendation under section II.D. of the Committee Report and the definition of ''entitlements'' under new § 206.451.) Therefore, for an operating rights owner who owns 25 percent of the operating rights for a Federal lease in the agreement, if 100 MMBtu of gas production are allocable to the lease, royalty is due on 25 MMBtu.

Notwithstanding that royalties are due from each operating rights owner based on its entitled share, the operating rights owner may be able to report and pay royalties on a different basis as will be discussed later in the preamble with respect to changes to part 211.

Further, for mixed agreements, that is, agreements comprised of leases with different lessors, royalty rates, and/or funds distributions, to provide some relief to small operating rights owners (defined below) who cannot market their entitled share of production each and every month, MMS is proposing an exception whereby royalties could be paid monthly on takes (defined under new § 206.451), subject to an annual adjustment to entitlements. This issue is addressed in detail in section II.D of the Committee Report (example on page 68).

New § 202.450(d) also would include procedures to value the portion of any production to which an operating rights owner is entitled but does not take. This provision is important because the operating rights owner must pay royalty on the non-taken portion. In most cases, value would be based on the weighted average value of the gas that was taken from the lease. This issue also is addressed in section II.D of the Committee Report.

Part 206

MMS is proposing a new subpart J for 30 CFR Part 206 that would be applicable only to valuation of Federal gas. Like part 202, MMS would amend existing subpart D to remove references to Federal gas, but would preserve all the provisions for valuing Indian gas under that subpart. Therefore, Indian gas valuation would not be affected by this rulemaking.

The new subpart J for Federal gas basically would retain the valuation provisions of existing subpart D applicable to Federal gas. In fact, for some gas production from Federal leases, the valuation rules would not change at all. However, to simplify the rules and to provide new valuation mechanisms responsive to changes in the gas market, MMS is proposing alternative valuation rules that would determine gas values based on published indices. Transportation allowance procedures also would be simplified for all producers. Several of the more important changes are described below.

Section 206.451 Definitions

MMS would retain almost all of the definitions in existing § 206.151. However, § 206.451 also would include many new definitions for terms used in the alternative valuation sections and other new sections of the rules. These definitions are contained in attachment 5 to the Committee Report. Most of these definitions are self-explanatory and are best understood when explained below in the context in which they are used.

MMS is proposing a modified definition for ''gathering'' to assist in distinguishing that function from transportation. Under this proposed definition, some movement of gas which is now gathering would fall within the definition of transportation. This change would be a fundamental change in existing regulations. Under current regulations, transportation constitutes movement of gas to a remote market away from the lease, and gathering constitutes movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS Outer Continental Shelf (OCS) operations personnel for onshore and OCS leases, respectively. The change reflected in the proposed rule's definition is one element of overall negotiated concessions by all parties involved in the Committee proceedings. The basis for the proposed change is addressed in section II.E. of the Committee Report.

A new definition also is proposed for ''small operating rights owner.'' These persons would be granted an exception from the obligation to report and pay royalties on their entitled share of production each month, and could pay based on their takes subject to an annual adjustment to entitlements. This is addressed in § 202.450 and in § 211.18. A small operating rights owner would be defined as a person who produces less than 6,000 Mcf/day total U.S. gas production *and* less than 1,000 bbls/day total U.S. oil production. This includes production from all domestic properties, Federal and non-Federal. (See page 67 of the Committee Report.)

Section 206.452 Valuation Standards—Unprocessed Gas

In most respects this section is the same as existing § 206.152. Therefore, for Federal gas production that is not processed and does not qualify for the proposed alternative valuation methods, discussed below, valuation would occur under this section. The valuation procedures essentially would be the same as under the existing rules in § 206.152.

However, there are a few changes in this proposed rule. Section 206.452(a)(3) would provide that gas which is sold or otherwise transferred to the lessee's marketing affiliate (a defined term) would be valued based upon the sale by the marketing affiliate. Thus, the applicable valuation procedure would depend on the marketing affiliate's sale. That sale would determine whether one of the new alternative valuation methods applies. Therefore, as explained further below, if the marketing affiliate sells unprocessed gas under an arm's-length dedicated contract, it could *not* use the alternative valuation methods. Other types of gas disposition by the marketing affiliate might qualify for the alternative valuation methods. Page 15 of the Committee Report provides a complete explanation of how such gas may be valued.

Under § 206.452(b), the valuation provisions applicable to gas sold under arm's-length contracts, value would be determined the same as under the existing rules, *i.e.*, based on the lessee's gross proceeds. However, if gas is sold under an arm's-length contract that is *not* dedicated (a dedicated contract is a contract where gas is sold from a specific source—see the definition in § 206.451), and if the gas production qualifies for valuation under the alternative valuation methods in § 206.454, then the lessee may *elect* to use those alternative valuation methods instead of the arm's-length valuation procedures in § 206.452(b). What gas qualifies for valuation under § 206.454 is discussed below in the preamble for that section. This issue is covered in detail in section II.A. of the Committee Report.

Paragraph (c) of § 206.452 applies to gas that is not sold under an arm's-length contract. It would provide that the lessee first must determine whether the gas qualifies for valuation under the new alternative valuation methods in § 206.454. Those qualification standards are discussed later in this preamble with respect to § 206.454. If the gas qualifies for valuation under § 206.454, the lessee would be *required* to use that section. (See recommendation on page 15 of the Committee Report.) If the gas does not qualify for valuation under § 206.454, then the benchmark valuation procedures under § 206.452(c) for non-arm's-length dispositions would apply. These procedures are the same as those under existing § 206.152. This issue is also discussed in detail in section II.A. of the Committee Report.

Of all the issues the Committee addressed, only one issue remains outstanding—improved benchmarks for valuing Federal gas sold under non-arm's-length contracts (*i.e.*, §§ 206.452(c) (1), (2) and (3)) when the gas is not subject to valuation under the new provisions of § 206.454. This issue, representing a small portion of overall Federal gas production, is the only issue on which the Committee did not reach consensus. (See section II.B. of the Committee Report.) MMS plans to issue a separate rulemaking that will improve the existing benchmarks. For that rulemaking, MMS will take under consideration the deliberations of the committee and invites any interested party to submit suggestions for improvements to the benchmarks with comments submitted on this proposed rulemaking.

Paragraph (g) of § 206.452 is the provision that corresponds to existing § 206.152(i). The existing provision states that ''Notwithstanding any other provision of this section,'' value cannot be less than the gross proceeds accruing to the lessee for lease production.

MMS is proposing to amend this section to eliminate the above-quoted introductory clause and to expressly exclude gas valued under an index-based method under § 206.454. This change is necessary to make it clear that if a provision of § 206.452 permits a lessee to value gas using an index-based method under the new alternative valuation methods in § 206.454, it would not be required to compare that index-based value to its gross proceeds.

Paragraph (i) of § 206.452, which corresponds to existing § 206.152(j), also would be amended to exclude gas valued using an index-based method under § 206.454. The diligence standard addressed in this paragraph is inapplicable to index-based valuation.

Section 206.453 Valuation Standards—Processed Gas

This section applies to the valuation of gas that is processed by the lessee. The changes proposed to modify this section from existing § 206.153 basically parallel the changes discussed in the previous section regarding the modifications in proposed § 206.452 from existing § 206.152. However, because this section addresses valuation of residue gas and gas plant products, there are some additional differences.

Under § 206.453(b), the valuation provision applicable to residue gas and gas plant products sold under arm's-length contracts, value would be determined the same as under the existing rules; *i.e.,* based on the lessee's gross proceeds.

However, if residue gas is sold under an arm's-length contract that is *not* dedicated (see the definition of ''dedicated'' in § 206.451), and if the gas production qualifies for valuation under the alternative valuation methods under § 206.454, then the lessee could *elect* to apply those provisions instead of the arm's-length valuation procedures in § 206.453(b). This issue is discussed with unprocessed gas in section II.A. of the Committee Report. Likewise, for NGL's, elemental sulfur and drip condensate associated with such residue gas, the lessee may *elect* to apply § 206.454 to value those products. The alternative valuation methods in § 206.454 would not be applicable to carbon dioxide, nitrogen or other non-Btu gas plant products. Section II.C. of the Committee Report provides a more complete explanation of this issue.

Under § 206.453(c), for residue gas or gas plant products not sold under an arm's-length contract, the lessee first must determine whether the residue gas or gas plant product is subject to valuation under § 206.454. For residue gas that is subject to § 206.454, the lessee would be *required* to use that section. (This proposal is explained on page 15 of the Committee Report.) Otherwise, valuation under this section would be the same as under existing § 206.153.

The proposed changes to the remaining paragraphs of § 206.453 are the same as those discussed above for § 206.452. Some additional changes applicable to both unprocessed gas and processed gas (both new §§ 206.452 and 206.453) not previously discussed are:

—MMS would delete all references in this new subpart to FERC maximum lawful prices because of deregulation.
—All references to warranty contracts would be eliminated because MMS does not believe there are any still in effect.
—The provisions of § 206.155 of the existing rules requiring dual accounting for certain Federal gas production (not Indian gas production) are not included in proposed subpart J based on the Committee's recommendation under section II.H. of the Committee Report.

Section 206.454 Alternative Valuation Standards for Unprocessed Gas and Processed Gas

This section is the principal new section for this proposed rule. It would add alternative gas valuation methods to the existing rules using published index prices and other criteria that should facilitate valuation in many circumstances.

However, this alternative valuation section would not be applicable to all gas. First, it would not apply at all to unprocessed gas or residue gas sold under a dedicated arm's-length contract, defined in proposed § 206.451 as a contractual commitment to deliver gas from a specific lease or well. For a discussion of why the Committee excluded gas sold under arm's-length dedicated contracts see section II.A.3 of the Committee Report.

Second, this alternative gas valuation section is applicable only to gas production from certain leases. Those leases must be in a zone (MMS-defined geographic area containing blocks or fields as defined in proposed § 206.452) with an active spot market and published indices, or be deepwater OCS leases. A complete discussion of these zones begins on page 48 of the Committee Report.

An active spot market is defined in proposed § 206.451 as a market where one or more MMS-acceptable publications publish bidweek prices (or if bidweek prices are not available, first-of-the-month prices) for at least one index pricing point in the zone. An index pricing point, or IPP, also is a defined term in § 206.451. Page 19 of the Committee Report includes diagrams of IPP's for various connection situations.

If the production does not qualify for valuation under this section because the lease is not in a zone with an active spot market with published indices, then the lessee would be required to value the production under §§ 206.452 or 206.453, as applicable. It also should be noted that this section would not apply to carbon dioxide, nitrogen, or other non-Btu gas plant products because all the alternative valuation methods are Btu-based.

If the production qualifies for valuation under this section, then the lessee would have a series of elections and choices for valuation based on how the production is sold.

1. For *unprocessed* gas sold under an arm's-length non-dedicated contract, the lessee could elect to use either an index-based method under this section (described below) or the gross proceeds valuation provision of § 206.452(b)(1).

2. For *unprocessed gas* sold non-arm's-length, the lessee must value the gas under this section using either an index-based method or, if the gas is sold to the lessee's affiliated purchaser (who is not a marketing affiliate) and if that affiliate sells the gas under an arm's-length contract, then the affiliate's gross proceeds (determined under § 206.452) are the value. Sales to marketing affiliates would be excluded here because, as provided in § 206.452(a)(3), valuation would be required on the basis of the marketing affiliate's sale.

3. For *residue gas* sold under an arm's-length non-dedicated contract, the lessee could elect to use either an index-based method under this section or the gross proceeds valuation procedure of § 206.453(b)(1).

4. For *residue gas* sold non-arm's-length, the procedure is the same as for unprocessed gas sold non-arm's length in paragraph 2 above.

5. If the lessee values residue gas using an index-based method, then the lessee has a choice on how to value the *NGL's, elemental sulfur and drip condensate* associated with that residue gas. It could either use the same index-based price per MMBtu used to value the associated residue gas, or it could use the procedures in §§ 206.453 (b) or (c) depending on whether the products are sold arm's-length or non-arm's-length.

6. If the lessee values the residue gas under an arm's-length non-dedicated contract using § 206.453(b), or if the lessee uses its affiliate's arm's-length gross proceeds under this section (§ 206.454(a)(2)(ii)(B)), then the lessee also has a choice on how to value the *NGL's, elemental sulfur and drip condensate.* It could use the same price per MMBtu used to value the associated residue gas. Alternatively, it could use §§ 206.453 (b) or (c), depending on whether the products are sold arm's-length or non-arm's-length.

Elections 1 and 2 are explained in section II.A.3.b. of the Committee Report. Elections 3, 4, 5, and 6 are explained in section II.C. of the Committee Report.

Paragraph (a)(3) of § 206.454 would provide four conditions to using the alternative valuation methods just described. First, there must be an active spot market for the gas subject to the valuation. As explained above, active spot market is defined in § 206.451.

Second, the gas must actually flow, or be capable of flowing, through at least one pipeline with at least one published index applicable to the zone.

Third, for all leases in a zone:

1. All unprocessed gas and residue gas sold under an arm's-length non-dedicated contract must be valued the same under this section. Therefore, for all such gas in the zone the lessee must make the same election to use either an index-based method or §§ 206.452(b) or 206.453(b), as applicable.

2. All unprocessed gas and residue gas produced from leases in the zone not sold under an arm's-length contract

must be valued using the same method where the lessee has an election. Therefore, if for one lease the lessee's affiliate sells the gas arm's-length and the lessee elects to use that value instead of an index-based value, for every other lease in the zone where the affiliate sells arm's-length the lessee must use the affiliate's arm's-length gross proceeds for valuation. If there are other leases in the same zone where, for example, the lessee's affiliate did *not* sell the gas under an arm's-length contract, under paragraphs (a)(1)(ii) or (a)(2)(ii) of § 206.454 there is no election for those leases and the lessee would be required to use index for those situations.

3. For all residue gas from leases in the zone valued under paragraphs (a)(2)(i) or (ii) of § 206.454 using the index-based method, the lessee must value all the NGL's, elemental sulfur and drip condensate associated with that residue gas using the same method. Thus, the lessee must use either an index-based method to value all such products in the zone or it must use §§ 206.453 (b) or (c), as applicable.

4. For all residue gas from leases in the zone valued under paragraphs (a)(2)(i) or (a)(2)(ii)(B) of § 206.454 using a gross proceeds method, the lessee must value all the NGL's, elemental sulfur and drip condensate associated with that residue gas using the same method. Therefore, the lessee must use either the price per MMBtu of the associated residue gas to value all such products in the zone or it must use §§ 206.453 (b) or (c), as applicable.

Fourth, the lessee's elections for valuation in each zone must be made for a period of 2 calendar years. If the lessee adds production from leases in the zone during that 2-year period, or acquires new leases in the zone, that production would be valued under the same election.

If the lessee does not satisfy all of the four above-described criteria, then it must value production under §§ 206.452 and 206.453. These criteria are listed on page 16 of the Committee Report.

Paragraph (a)(6) of § 206.454 would address an issue that the Committee did not consider. It involves situations where a lessee entered into a gas contract settlement prior to the effective date of a final rule in this matter, and actually receives the settlement payment before or after the effective date of the final rule. Under current MMS interpretation of the gross proceeds requirements, the payment the lessee receives under that gas contract settlement may be attributable in whole or in part to production that occurs after the effective date of this rule. This paragraph would provide that any portion of the gas contract settlement payment attributable to that production would be subject to royalty in addition to any index-based or other value established under § 206.454.

By way of illustration, assume that the lessee entered into a gas contract settlement and received a lump-sum payment in January 1995 for a gas sales contract for lease production that would have been in effect until June 1997. Assume further that under MMS' current royalty valuation procedures, MMS would consider the lump-sum payment to be attributable pro rata to the production that occurs from the lease until June 1997 at the rate of $0.10 per MMBtu. Under paragraph (a)(6) of § 206.454, if the index-based value determined for production for May 1996 were $2.00, the lessee would be required to pay royalty on $2.10.

Paragraph (a)(6) of § 206.454, as proposed, does not require that royalty be paid on any amounts attributable to gas contract settlements entered into after the effective date of the rule where the lessee uses an index-based or other value under § 206.454. (Of course, MMS does consider certain of such payments to be subject to royalty for lessees using gross proceeds to value production, which is not addressed in this paragraph.) MMS specifically requests comment on whether amounts for gas contract settlements entered into after the rule's effective date should be subject to royalty for lessees who use index-based or other values under § 206.454.

Paragraph (b) of § 206.454 would explain how to determine the index value for gas production when the lessee must use, or elects to use, an index-based method. Determination of the index value depends on whether the gas flows or could flow through a single connect, a split connect or a multiple connection. This determination must be made for each well on a lease because different wells may have different connections. A discussion of determining index values begins on page 18 of the Committee Report under *Index Pricing Points*.

For a single connect, the index value is the index price for the first index pricing point (IPP). For that IPP, the lessee will have selected a publication from the MMS-acceptable list in accordance with § 206.454(d). The price published in that publication for that month for that IPP would be used to value all production from the well that month.

If the well has a split connect or a multiple connection, the lessee would be required to elect one of two methods to calculate the index value:

1. Weighted-average index value. This index would be calculated by first multiplying the volume of gas from the well *actually* flowing to each IPP by the applicable index price for that IPP (using the publication the lessee selected under paragraph (d) of § 206.454).

(Example: IPP1—10,000 MMBtu × $1.20/MMBtu = $12,000; IPP2—20,000 MMBtu × $1.30/MMBtu = $26,000; IPP3—10,000 MMBtu × $1.20/MMBtu = $12,000). The numbers for each IPP are then added, equaling a total of $50,000. That sum is divided by the total volume (40,000 MMBtu) and the resulting quotient ($1.25/MMBtu) is the index value. The amount of gas actually flowing to each IPP is determined by using the nominations confirmed at the first of the month or the total nominations confirmed during the month, applied consistently for the two-year election period. If the actual flow of the gas during the month is different from the flow determined by the confirmed nominations used to calculate the value under this paragraph, the weighted average index value will not be recalculated using the actual flow volume. This index value would apply to all production from the well no matter which IPP the gas actually flowed through.

2. Fixed index value. First, for each IPP through which gas from the well flows *or could flow,* determine the average of the applicable monthly index prices for the *previous* calendar year using the publication selected for that year. Array the average prices determined for each IPP from highest at the top to lowest at the bottom. If there are only two IPP's, select the IPP associated with the highest average price. If there are three or more IPP's, select the IPP associated with the second highest average price. For whichever IPP is selected, go to the publication selected for that IPP for the current year (which could be a different publication than the one used the previous year). The index price for the current month for the IPP in that publication is the index value for all gas production from the well that month no matter where the gas actually flows. Example: Last year's 12-month average and this month's index price for each IPP through which the lessee's gas flows or could flow are:

	Last year's average	Current month
IPP2	$1.89/MMBtu	$2.05/MMBtu.

	Last year's average	Current month
IPP3	$1.86/MMBtu	$2.00/MMBtu.
IPP1	$1.85/MMBtu	$2.10/MMBtu.

The second IPP in the array, IPP3, is used to value production in the current year. For this month, the index price in the publication selected for IPP 3 is $2.00/MMBtu. This index value is used to value all production from the well.

If the result of the calculation is that the selected average index price (either the highest or second highest, as applicable) is identical to another average index price, then the calculation of the average index prices for the previous year would have to be redone to eight decimal places, and the process would then proceed the same.

The lessee would be required to elect to use either the weighted average index method or the fixed index method for the two-calendar-year election period. The lessee also would have to apply the same elected method to all wells connected to the same split connect or multiple connection. But the lessee could use the weighted average index method for one split connect in a zone and the fixed index method for another split connect in the same zone. For the Committee's discussion of this issue, see pages 20–23 of the Committee Report.

Paragraph (c) of § 206.454 would provide that the lessee would be entitled to deduct an applicable transportation allowance from the index value to determine the value for royalty purposes. Transportation allowances are addressed later in this preamble.

Paragraph (d) of § 206.454 would explain how a lessee selects an acceptable publication for the index price from a list of acceptable publications that MMS periodically will publish in the Federal Register. (See Committee Report discussion under *Choice of Index Publication,* beginning on page 29.)

Paragraph (e) of proposed § 206.454 relates to determination of the final safety net median value. In summary, as is explained in substantial detail at pages 33 to 45 of the Committee Report, the lessee would be required to compare its alternative value determined under this section to the final safety net median value for each zone. If its alternative value is lower than the final safety net median value (which would be based on arm's-length gross proceeds valuation information reported to MMS on Form MMS–2014 and other sources), then the lessee would be required to pay additional royalty and, in some cases, late payment interest.

Paragraphs (e)(1) through (e)(3) of § 206.454 would explain in substantial detail what reported information and other data MMS would use to calculate the final safety net median value.

Paragraph (e)(4) of § 206.454 would explain that the final safety net median value for a zone would be calculated by arraying the prices per MMBtu derived from the collected data from highest to lowest (at the bottom). The final safety net median value would be that price at which 50 percent plus 1 MMBtu of the production (starting from the bottom) is sold. This value would apply for a calendar year.

The proposed rules would provide in paragraph (e)(7) of § 206.454 that a lessee could request a technical procedural review of the final safety net median value from the Associate Director for Royalty Management. The Associate Director's decision following that review would be a final Departmental decision not subject to further administrative review.

Paragraphs (e)(8) through (e)(10) of § 206.454 would explain how the lessee must determine whether it owes additional royalty based on the difference between the annual weighted average value of its production determined under this section and the final safety net median value for each zone. If its annual weighted-average value is lower than the final safety net median value, this proposed rule explains in detail what percentage of the difference the lessee must pay as additional royalty. That percentage depends upon what product is being valued (*e.g.* unprocessed gas, residue gas, or plant products) and which alternative valuation method is used. If the lessee's annual weighted average value is higher than the final safety net median value, it would owe no additional royalty and would not receive any credit or refund.

Under paragraph (e)(11) of § 206.454, for leases on certain OCS deepwater blocks that MMS specifies, the additional royalty calculations under paragraphs (e)(8), (e)(9), and (e)(10) would be made using adjusted transportation allowances because of the unusual distances involved. MMS also would use the final safety net median value for the closest zone where production flows or could flow.

Paragraph (e)(6) of § 206.454 would require that MMS publish the final safety net median value within 2 years after the end of the relevant calendar year. The Committee did not address the consequences of MMS not publishing the final safety net median value within two years. MMS requests comments on the appropriate consequences in this event. Options could include: (1) Using the initial safety net median value; or (2) having no additional royalties due; or (3) suspending interest until the final safety net median value is published.

Paragraph (e)(12) of § 206.454 would provide that MMS will endeavor to publish an *initial* safety net median value within 6 months following the end of the calendar year to give lessees an up-front approximation of the safety net median value. The lessee could then pay any additional royalty that may be due. If the lessee made an estimated payment following publication of the initial safety net median value and if the final safety net median value is lower than the initial safety net median value, then the lessee would receive a credit or refund of its overpayment.

This paragraph also would provide that the lessee could report any additional royalty payments using a one-line entry on Form MMS–2014 for each zone. If the lessee reports an estimated payment following the initial safety net median value, then following publication of the final safety net median value it must file an amended Form MMS–2014 adjusting any payments for each zone, if necessary. On this amended report, the lessee may recoup any overpayment by filing a credit adjustment. This *first* credit adjustment would not be subject to section 10 of the Outer Continental Shelf Lands Act, 43 U.S.C. § 1339, for the same reasons that adjustment of an estimated transportation or processing allowance from estimated to actual is not subject to section 10. See 30 CFR 230.461(f). However, if the lessee makes a second adjustment to that line for any zone, it would be subject to all of section 10's provisions including the 2-year limit and the approval requirements.

Finally, under this section, late payment interest would not accrue on any additional royalty owed until the date MMS publishes the *initial* safety net value. Therefore, for example, for calendar 1997, if the initial safety net value is published June 30, 1998, and if the lessee makes an estimated payment July 31, 1998, it would owe only 1-month's interest. If it did not pay any additional royalty until the final safety net median value is published, or if its estimated payment were deficient, interest would run from June 30, 1998, until the deficient royalty payments were made. The issue of interest is explained on pages 42–43 of the Committee Report.

These proposed rules would require in paragraph (e)(5) of § 206.454 that the final safety net median value must be based on a representative sample of data reflecting gross proceeds sales. Paragraph (f) of § 206.454 would explain how that representative sample would be determined. (See *Representative Sample* discussion beginning on page 44 of the Committee Report.)

Paragraph (g) of § 206.454 would provide that MMS would publish in the Federal Register the zones with an active spot market and published indices that are eligible for an index-based valuation method. MMS would consider such criteria as common markets served, common pipeline systems, simplification and easy identification, such as an offshore block or an onshore county. Under paragraph (h) of § 206.454, MMS would hold a technical conference if necessary and publish notice in the Federal Register that a zone is disqualified for the following calendar year. That notice would be published by September 1 of the preceding year.

Section 206.456 Transportation Allowances—General

If a lessee values gas at a point off the lease, this section would authorize a transportation allowance for the reasonable costs of transporting identifiable, measurable gas to that point. This section would also provide for an exception whereby MMS could approve an allowance for the transportation of bulk deepwater production upon request of the lessee. No allowance would be authorized for gathering costs. The basis for this proposal is contained in section II.E. of the Committee Report. The Committee Report used the term ''location differential,'' but this proposed rule uses the term ''transportation allowance'' for the same purpose. The transportation allowance would be applicable to unprocessed gas, residue gas and gas plant products, and would be available both in situations where production is valued under §§ 206.452 and 206.453, as well as under the new alternative valuation methods in § 206.454.

If gas flows (or, for some alternative valuation methods, gas *could* flow) through more than one pipeline segment to the point where value is determined, the applicable transportation allowance would be based on the total allowance for each segment determined under § 206.457. Therefore, if the gas flows through a jurisdictional pipeline and then a non-jurisdictional pipeline before it gets to the point where value is determined, the allowance would be based on the total for both segments.

MMS would add a new provision in § 206.456(a)(2) providing that the lessee's costs of compression downstream of the facility measurement point (FMP), incurred either by the payment of such cost under a contract or by performance of the compression by the lessee, is allowable as a transportation cost. Also, under this new provision, costs of boosting or compressing residue gas after processing would be part of the lessee's transportation allowance for residue gas. This issue is addressed in section II.F. of the Committee Report.

The remaining provisions are the same as in existing § 206.156, including limitations on the allowances.

Section 206.457 Determination of Transportation Allowances

This section would be organized differently from existing § 206.157. In addition to determining whether the transportation cost is arm's-length or non-arm's-length, the lessee would have to differentiate in some cases between jurisdictional pipelines (defined in § 206.451 as a pipeline with a rate regulated by FERC or a state agency) and non-jurisdictional pipelines (not FERC or state-agency regulated). This distinction is based on the Committee's recommendations for classifying pipeline systems on pages 23–24 of the Committee Report.

Paragraph (a) of § 206.457 would explain that if the lessee uses gross proceeds to value its gas, then the transportation allowance would be determined under paragraphs (b) or (c) of § 206.457, depending upon whether the pipeline is jurisdictional or non-jurisdictional and whether or not the transportation arrangement is arm's-length. If the lessee elects an index-based method to value its gas, then, as provided in paragraph (d) of § 206.457, the transportation allowance would also be determined under paragraphs (b) or (c) of § 206.457, if the lessee actually transports some gas to the IPP used for value. If the lessee elects an index-based method but *does not* flow any gas to the IPP used for value, then the transportation allowance would be determined under paragraph (d)(5) of § 206.457.

Paragraph (b) of § 206.457 would apply if the lessee determines value under § 206.452 or 206.453, or under the provisions applicable to arm's-length sales of gas by the lessee's affiliate (§§ 206.454(a)(1)(ii)(B) and 206.454(a)(2)(ii)(B)). If the value is determined under those sections and if the lessee transports either unprocessed gas, residue gas, gas plant products, or drip condensate through a *jurisdictional* pipeline, the transportation allowance would be based on the reasonable, actual contract rate paid. (See Committee recommendation on page 23 of the Committee Report.) This would apply to both arm's-length and non-arm's-length situations. Similarly, if the lessee values under those sections and transports production though a *non-jurisdictional* pipeline under an *arm's-length contract*, the transportation allowance also would be based on the reasonable, actual contract rate paid. (See Committee recommendation on page 24 of the Committee Report.)

The remaining provisions of paragraph (b) are essentially the same as the arm's-length contract rate provisions in existing § 206.157.

Paragraph (c) of § 206.457 would apply in situations where value is determined under §§ 206.452 and 206.453 and transportation is through a *non-jurisdictional* pipeline under a *non-arm's-length contract* or no contract situations (see page 24 of the Committee Report). The transportation allowance provision that would apply would depend upon how much gas is transported through that pipeline under arm's-length transportation contracts.

If 30 percent or less of the gas in the pipeline flows under arm's-length transportation contracts, the allowance would be based on either:

(1) The lessee's reasonable actual costs determined under paragraph (c)(2) of § 206.457, which contains basically the same cost calculations as under the existing regulations; or

(2) A rate of $0.02/MMBtu for OCS leases or a *de minimis* rate for onshore leases not to exceed $0.09/MMBtu. MMS would periodically determine the onshore rate based upon available transportation cost data and publish it in the Federal Register. The rate would be applicable for 1 calendar year.

If more than 30 percent of the gas is transported under arm's-length contracts, the lessee could use either:

(1) Its reasonable actual costs for transportation; or

(2) A rate determined by arraying all of the arm's-length rates for the pipeline from highest at the top to the lowest at the bottom. The applicable rate would be the one closest to the 25th percentile from the bottom. An example is provided on page 26 of the Committee Report.

As noted above, the provisions of § 206.457(c)(2) used to determine reasonable actual costs are essentially the same as under existing § 206.157(b)(2). A new provision would be added to paragraph (c)(2)(iv)(A) of § 206.457 related to depreciation for purchased systems. This issue is discussed on pages 28 and 29 of the Committee Report.

Paragraph (d) of § 206.457 would apply to determine transportation allowances each month for gas valued under the new *index-based* valuation methods in § 206.454(b). The transportation allowance would be determined by the type of connection to the well (*i.e.*, single connect, split connect or multiple connection) and the type of index valuation method used. This issue is discussed under section II.A. of the Committee Report under *Location Differential (LD).*

Under § 206.457(d)(2), for a single connect, the transportation allowance for volumes actually transported to the IPP where value is determined would be determined under § 206.457 (b) or (c), as applicable. Thus, for example, if it is a jurisdictional pipeline or a non-jurisdictional pipeline with an arm's-length contract, § 206.457(b) would apply and the allowance would be based on the lessee's contract rate. By contrast, if it is a non-jurisdictional pipeline and the lessee has a non-arm's-length transportation contract, the allowance would be determined under § 206.457(c) based on the lessee's actual costs or one of the other alternatives in that paragraph. These proposals are listed on pages 23–24 of the Committee Report.

If the lessee's gas does not actually flow to the IPP, then the transportation allowance for that pipeline would be determined under § 206.457(d)(5) discussed below.

Paragraph (d)(3) of § 206.457 applies to situations where the lessee's gas production from a well with a split connect or multiple connection is valued using the weighted average index method under § 206.454(b)(2)(i). The lessee first would be required to determine the applicable transportation allowance, using either paragraph (b) or (c) of § 206.457, as applicable, for gas volumes actually transported to each IPP used in the calculation to value the lessee's gas from the well. Thus, if there are five IPP's used in the weighted average calculation, five allowances must be calculated. The lessee then must determine the volume weighted average transportation allowance per MMBtu for those five pipelines. That rate per MMBtu could then be deducted as the transportation allowance against the weighted average index value per MMBtu for all the lessee's production from the well. Page 25 of the Committee Report provides an example of calculating the weighted average transportation allowance.

Finally, paragraph (d)(4) of § 206.457 applies where the lessee's gas production from a well with a split connect or multiple connection is valued using the fixed index value method under § 206.454(b)(2)(ii) and where some of the lessee's gas actually flows to the IPP selected for value. In that situation, the transportation allowance for all the lessee's gas from the well would be determined based on the lessee's transportation allowance rate per MMBtu, determined under § 206.457 (b) or (c), as applicable, to transport gas to that IPP. Therefore, if IPP5 is the selected IPP for valuation purposes, and 20 percent of the lessee's gas from the well actually flows to that IPP, the transportation allowance rate per MMBtu for the pipeline to IPP5 also would be applied to the other 80 percent of the lessee's gas from the same well. If none of the lessee's gas actually flows to that IPP, then the lessee must use § 206.457(d)(5) to determine the allowance.

As noted above, there may be situations where gas does not actually flow to an IPP that is used to determine value. However, a transportation allowance rate must be determined for the pipeline or pipelines, to that IPP. Under § 206.457(d)(5), if it is a jurisdictional pipeline, the rate would be the maximum interruptible transportation (IT) rate for the pipeline that month (see page 23 of the Committee Report).

If the pipeline is a non-jurisdictional pipeline and the lessee is not affiliated with the owners of that pipeline, the rate would be based on either:

(1) A rate MMS would calculate for the lessee for a fee to cover MMS administrative costs; or

(2) A rate determined by the lessee based on such factors as rates paid under arm's-length contracts for that pipeline, the pipeline's published rates, and rates the lessee actually pays to the pipeline (see page 24 of the Committee Report).

If it is a non-jurisdictional pipeline and the lessee *is* affiliated with the owners of that pipeline, the applicable transportation allowance rate would be determined under the cost-based provisions of § 206.457(c) applicable to other non-arm's-length or no contract situations (see page 24 of the Committee Report).

Paragraph (e) of § 206.457 would require that the transportation allowance must be reported as a separate line item on the Form MMS–2014 unless MMS approves a different procedure (see page 23 of the Committee Report). However, all gas transportation allowance forms would be eliminated to make reporting simple. See section II.G. of the Committee Report for the Committee's recommendation on this issue.

The other paragraphs relating to interest assessments, adjustments, and actual or theoretical losses are essentially the same as under the existing rules. Certain changes would be made to account for the reduction in the reporting procedures.

Section 206.458 Processing Allowances—General

This section, which would allow a deduction for the reasonable actual costs of processing when value is determined under § 206.453, is the same as existing § 206.158. Therefore, the same limitations on allowances would apply as under the existing rules. No processing allowance would be applicable to gas plant products valued under § 206.454.

Section 206.459 Determination of Processing Allowances

This section would explain how the processing allowance is determined based on whether the lessee has an arm's-length or non-arm's-length (or no contract) processing agreement. This section is the same as existing § 206.159 with a few changes. Under § 206.459(b)(2)(iv)(A), which is part of the actual cost calculation for non-arm's-length or no contract processing situations, a new provision would be added regarding depreciation for newly acquired facilities. The issue regarding depreciation is discussed on page 24 of the Committee Report.

The most significant change would be in paragraph (c) of § 206.459. As with transportation allowances, the reporting requirements would be simplified by eliminating all processing allowance forms. The lessee only would be required to report the processing allowance as a separate line on the Form MMS–2014 unless MMS approves a different reporting procedure. (See section II.G. of the Committee Report.) Of course, all allowances are subject to audit, and the interest assessment and adjustment provisions in §§ 206.459 (d) and (e) would apply.

Part 211

In a separate rulemaking, MMS has proposed regulations regarding who is liable for royalty and other payments due on Federal and Indian leases (60 FR 30492, June 9, 1995). That rulemaking also explains who is required to report and pay royalties. MMS does not address in that other rulemaking the reporting requirements for mixed agreements and, instead, is proposing those rules in this rulemaking. Therefore, MMS is proposing here paragraph (c) of what would be a new § 211.18 regarding who is required to report and pay royalties.

The Committee was requested to consider payment and reporting for agreements which contain only Federal leases with the same royalty rate and funds distribution. The Committee concurred with an MMS draft proposal that payment should be made on a takes basis with an exception to seek approval for payment on an entitlements basis. (See pages 63–64 of Committee report.) Because this subject was beyond the Committee's charge, MMS included it in that separate rulemaking (60 FR 30492, June 9, 1995).

This new paragraph would explain royalty reporting requirements for leases in mixed agreements. The basic requirement is that an operating rights owner in a Federal lease in a mixed agreement must report and pay royalties each month based on its entitled share of production. This issue is described in section II.D. of the Committee Report.

However, in a provision parallel to what is proposed in this rulemaking for § 202.450(d), discussed above, an operating rights owner who meets the definition of small operating rights owner in § 206.451 could report and pay royalties each month based on its takes. Then, within 6 months after the end of the calendar year, it would have to adjust its reports and pay based on its entitled share if it is greater than the takes.

This proposed rule would allow a credit for overtaken volumes for the calendar year. MMS specifically requests comments on how this credit should be processed.

Under § 211.18(c)(2)(iii), if the volume of production the small operating rights owner reported and paid on for the calendar year is equal to or greater than its entitled share of production for the year, no interest would be assessed for any individual months where volumes were underreported. However, MMS would assess interest for any volumes reported on takes but where the value of those volumes is underpaid. For example, assume that the entitled share of production is 10 MMBtu of production each month. For the year, the small operating rights owner reported and paid on 120 MMBtu. However, in July, only 5 MMBtu with a value of $1.00 per MMBtu was reported. The correct value should have been $2.00 per MMBtu. No interest is owed for the underreported 5 MMBtu that month. However, for the 5 MMBtu that were reported, interest is owed on the $1.00 of underreported value.

If the total volume the small operating rights owner reported and paid on for the calendar year is less than its entitled share for that year, it would be required to pay interest on all underreported volumes and any associated underpaid royalties.

The rule would provide an exemption from the basic requirement that all operating rights owners must report pay based on entitlements if they agree among themselves to use an alternative method. The only condition is that royalties must be reported and paid on the full volume of production for the lease and the agreement.

Finally, under many of the proposals contained in this rulemaking, additional reporting on the Report of Sales and Royalty Remittance (Form MMS–2014) would be necessary to implement the proposals. For example, where a small operating rights owner pays on its takes, MMS would need to be alerted via the Form MMS–2014 that it may not receive royalties on the full share of production allocable to the lease during the calendar year. Lessees using index-based methods, as well as lessees using alternative methods to value the gas plant products, would need to notify MMS on the Form MMS–2014 in order for MMS to apply the safety net median value procedure. Also, lessees paying on gross proceeds in zones with an active spot market would need to alert MMS on the Form MMS–2014 whether or not those gross proceeds are based on arm's-length or non-arm's-length contracts. MMS requests input on how to best accommodate this supplementary reporting.

IV. Procedural Matters

The Regulatory Flexibility Act

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

Executive Order 12630

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

Executive Order 12778

The Department has certified to the Office of Management and Budget that these final regulations meet the applicable standards provided in Sections 2(a) and 2(b)(2) of Executive Order 12778.

Executive Order 12866

This rule is significant under Executive Order 12866 and has been reviewed by the Office of Management and Budget.

The Committee's many objectives for improving the process included simplicity, administrative cost savings, and revenue neutrality for both lessees and lessors.

A key component of the Committee's recommendations, the ''safety net,'' assured MMS and the States that index-based values would not result in substantially lower revenues than those received under the current method of gross proceeds. The ''safety net'' allows MMS the ability to monitor the revenue impact of index-based valuation by comparing index values to the median value of all gross proceeds in the area.

The Committee was not able to demonstrate empirically the revenue neutrality of this proposed rule for a number of reasons. Although revenue neutrality could not be documented, the Committee anticipated that the use of published indices may ultimately reduce MMS' and industry's administrative costs related to royalty payments.

The benefits of the proposed rule to both MMS and its constituents are numerous. Benefits to independent producers include: (1) The ability to continue to pay royalties on gross proceeds received under dedicated arm's-length contracts and (2) an option to eliminate administrative costs associated with natural gas liquid royalty payments by paying on a wellhead value for non-dedicated arm's-length contracts.

Benefits to all producers include: (1) An option to value production from arm's-length non-dedicated contracts on published indices in areas with active spot markets; (2) elimination of the requirement to submit transportation and processing forms for Federal gas leases; (3) elimination of dual accounting for gas produced from Federal leases; and (4) greatly simplified definitions of gathering and compression.

MMS and State governments realize administrative cost savings through: (1) Reduction in audit, enforcement, and litigation costs associated with determining the proper value of federal gas sold in the FERC Order 636 environment; (2) reduction in retroactive adjustments made to royalty reports to account for sales adjustments made from gas pools and market centers; and (3) elimination of resources necessary to collect and verify all forms related to transportation and processing allowances.

Paperwork Reduction Act

This rule does not contain information collection requirements which require approval by the Office of Management and Budget. The proposed amendments to the gas valuation regulations would reduce reporting requirements by not requiring the following forms to be filed for gas production from Federal onshore and offshore mineral leases:

MMS–4109—Gas Processing Allowance Summary Report (OMB No. 1010–0075)

MMS–4295—Gas Transportation Allowance Report (OMB No. 1010–0075)

National Environmental Policy Act of 1969

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

List of Subjects

30 CFR Parts 202 and 206

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

30 CFR Part 211

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

Dated: August 4, 1995.

Bob Armstrong,

Assistant Secretary—Land and Minerals Management.

For the reasons set out in the preamble, parts 202, 206, and 211 of title 30 of the Code of Federal Regulations are proposed to be amended as follows:

PART 202—ROYALTIES

1. The authority citation for part 202 is revised 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.*

Subpart B—Oil, Gas, OCS Sulfur, General

2. Section 202.51 is amended by revising paragraph (b) to read as follows:

§ 202.51 Scope and definitions.

* * * * *

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

3. The heading of subpart D is revised to read ‘‘Indian Gas.’’

4. Section 202.150 is amended by adding a new sentence at the beginning of paragraph (a) as set forth below and by removing the words ‘‘, except helium produced from Federal leases,’’ in the first sentence of paragraph (a); removing the words ‘‘a Federal or’’ from paragraph (b)(1), paragraph (e)(2), and paragraph (f), and substituting the word ‘‘an’’ in their place; removing the words ‘‘or if MMS determines that gas was unavoidably lost or wasted from an OCS lease,’’ in paragraph (c); removing the words ‘‘Federal or’’ from the first and third sentences of paragraph (e)(1); and by removing the words ‘‘Federal and’’ from paragraph (f) introductory text.

§ 202.150 Royalty on gas.

(a) This subpart applies only to Indian leases. * * *

* * * * *

5. Section 202.151 is amended by removing the phrase ‘‘Federal and’’ in the second sentence of paragraph (a).

6. Section 202.152 is amended by removing the words ‘‘, except that for OCS leases in the Gulf of Mexico, gas volumes and BTU heating values shall be reported at a standard pressure base of 15.025 psia and a standard temperature base of 60 °F,’’ from the second sentence of paragraph (a)(1).

7. A new subpart J is added as follows:

Subpart J—Federal Gas

Sec.
202.450 Royalty on gas.
202.451 Royalty on processed gas.
202.452 Standards for reporting and paying royalties on gas.

Subpart J—Federal Gas

§ 202.450 Royalty on gas.

(a) *Royalty rate.* Royalties due on gas production from leases subject to the requirements of this subpart must be at the rate established by the terms of the lease. Royalty must be paid in value unless MMS requires payment in kind. When paid in value, the royalty due must be the value, for royalty purposes, determined under 30 CFR part 206 multiplied by the royalty rate in the lease.

(b) *Gas subject to royalty.* (1) All gas (except gas unavoidably lost or used on, or for the benefit of, the lease, including that gas used off-lease for the benefit of the lease when such off-lease use is permitted by MMS or BLM, as appropriate) produced from a Federal lease to which this subpart applies is subject to royalty. However, except as provided in § 202.451(b), in no instances will any gas be approved for use royalty free downstream of the facility measurement point approved for the gas.

(2) When gas is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of MMS or BLM, as appropriate, or at a production facility handling unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty free.

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

(c) *Avoidably lost and wasted gas and compensatory royalty.* (1) If BLM determines that gas was avoidably lost or wasted from an onshore lease, or that gas was drained from an onshore lease for which compensatory royalty is due, or if MMS determines that gas was avoidably lost or wasted from an OCS lease, then the value of that gas must be determined in accordance with 30 CFR part 206.

(2) If a lessee receives insurance compensation for unavoidably lost gas, royalties are due on the amount of that compensation. This paragraph does not apply to compensation through self-insurance.

(d) *Agreements.* (1) Royalties are due on production allocated to Federal leases under the terms of an agreement in accordance with the following requirements:

(i) Royalty rate—Royalties are due based on the royalty rate specified in the lease (or as modified by the agreement).

(ii) Volume—Royalties are due each month on the full share of production allocated to the lease under the terms of the agreement. For each operating rights owner (working interest owner) in the lease, royalties are due on its entitled share of production allocable to the lease; *provided that,* for production allocable to a small operating rights owner (defined in § 206.451) of a lease committed to a mixed agreement (also defined in § 206.451), royalties may be reported and paid on a monthly basis on takes volumes, even if the total volume reported and paid for that lease for the month is less than the total volume of production allocable to the lease under the agreement; *provided further,* for each calendar year in which royalties are paid by or on behalf of a small operating rights owner based on its takes volumes, within 6 months after the end of that calendar year the operating rights owner must compare its total entitled volumes of production for the calendar year to its total takes volume for that calendar year and pay additional royalties on any portion of its annual entitled volumes not taken during the calendar year based on the value determined under paragraph (d)(1)(iii)(D) of this section. If the small operating rights owner has taken more than its entitled share of production for the calendar year and has paid royalty on that taken volume, the small operating rights owner will be entitled to a credit for the over-taken volumes.

(iii) Value—The value of production that an operating rights owner in a Federal lease takes must be determined under 30 CFR part 206. However, if an operating rights owner in a Federal lease in a mixed agreement takes more than its entitled share of production for any month, the value of its entitled share must be the weighted-average value of the production, determined under 30 CFR part 206, that the operating rights owner takes during that month based on the acceptable method.

(iv) Value for mixed agreements—untaken volumes—For mixed agreements, the value of production that an operating rights owner in a Federal lease is entitled to but does not take for any month must be determined as follows:

(A) Where the operating rights owner takes a portion of its entitled share of production from a lease, value for the untaken volumes must be based on the weighted average of the value of the production taken by that owner for that month from the same lease in the agreement as determined under 30 CFR part 206.

(B) If the operating rights owner takes none of its entitled share and that production would have been valued using an index-based method under § 206.454 had it been taken, then the value of production not taken for that month must be determined under § 206.454(b) as if it had been taken. If the operating rights owner uses a weighted-average index value under § 206.454(b)(2)(i), the most recent prior month's confirmed nominations must be used in calculating the weighted-average index value.

(C) If the operating rights owner takes none of its entitled share of production from a lease and that production cannot be valued under paragraph (B) above, then the value of production not taken for that month must be determined based on the first applicable of the following methods:

(*1*) The weighted average of the operating rights owner's gross proceeds under arm's-length contracts during the previous three months for production from or attributable to the same lease in the agreement;

(*2*) The weighted average of the operating rights owner's gross proceeds under arm's-length contracts during the previous three months for production from or attributable to other leases in the agreement;

(*3*) The weighted average of the operating rights owner's gross proceeds under arm's-length contracts for that month in the field or area.

(*4*) An index-based value for that month determined under § 206.454 if the lease is in a zone with an active spot market and acceptable published indices and the gas production flows or could flow to an IPP.

(*5*) A value determined for that month under §§ 206.452(c) or 206.453(c), as applicable.

(D) For a small operating rights owner of a Federal lease who elects to pay royalties on takes under paragraph (d)(1)(ii) of this section, the value of any portion of its entitled share not taken during the calendar year must be based on the first applicable of the following methods:

(*1*) The weighted-average value of the production the operating rights owner takes from the same lease in the agreement during the calendar year;

(*2*) The weighted-average value of the production the operating rights owner takes from other leases in the agreement during the calendar year;

(*3*) A value determined under §§ 206.452(c) or 206.453(c), as applicable.

(v) Reporting and payment—Royalties must be reported and paid as provided in part 211 of this title.

(2) If a lessee takes less than its entitled share of agreement production for any month, but royalties are paid on the full volume of its entitled share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods at the time the lessee subsequently takes more than its entitled share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

(3) If a Federal lessee takes less than its entitled share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (d)(1) of this section, but consistent with the purpose of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(e) *Exception for all agreement production.* For production from Federal leases which are committed to agreements, upon request of a lessee MMS may establish the value of production under a method other than the method required by the regulations in this title if: (1) the proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms and agreement terms; (2) to the extent practical, persons with an interest in the agreement, including royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

§ 202.451 Royalty on processed gas.

(a) A royalty, as provided in the lease, must be paid on the value of: (1) any drip condensate; and (2) residue gas and all gas plant products resulting from processing the gas produced from a lease subject to this part. MMS will authorize a processing allowance for the reasonable, actual costs of processing the gas produced from Federal leases. Processing allowances must be determined in accordance with Subpart J of 30 CFR Part 206.

(b) A reasonable amount of residue gas will be allowed 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 each lease's residue gas necessary for the operation of the processing plant will be allowed royalty free.

(c) No royalty is due on residue gas, or any gas plant product resulting from processing gas, which is reinjected into a reservoir within the same lease, unit area, or communitized area, when the reinjection is included in a plan of development or operations and the plan has received BLM or MMS approval for onshore or offshore operations, respectively, until such time as they are finally produced from the reservoir for sale or other disposition off-lease.

§ 202.452 Standards for reporting and paying royalties on gas.

(a)(1) Gas volumes and Btu heating values, if applicable, must be determined under the same degree of water saturation. Gas volumes must be reported in units of one thousand cubic feet (Mcf), and Btu heating value must be reported at a rate of Btu's per cubic foot, at a standard pressure base of 14.73 psia and a standard temperature base of 60°F, except that for OCS leases in the Gulf of Mexico, gas volumes and Btu heating values must be reported at a standard pressure base of 15.025 psia and a standard temperature base of 60°F. Gas volumes and Btu heating values must be reported, for royalty purposes, on the same water vapor saturated or unsaturated basis prescribed in the lessee's gas sales contract.

(2) The frequency and method of Btu measurement as set forth in the lessee's contract must be used to determine Btu heating values for reporting purposes. However, the lessee must measure the Btu value at least semiannually by recognized standard industry testing methods even if the lessee's contract provides for less frequent measurement.

(b)(1) Residue gas and gas plant product volumes must be reported as specified in this paragraph.

(2) Carbon dioxide (CO_2), nitrogen (N_2), helium (He), residue gas, and any other gas marketed as a separate product must be reported by using the same standards specified in paragraph (a) of this section.

(3) Natural gas liquids (NGL's) must be reported in standard U.S. gallons (231 cubic inches) at 60°F, except for zones with an active spot market and valid published indices. In those zones, NGL's must be reported based on its heating value in accordance with the MMS Oil and Gas Payor Handbook.

(4) Sulfur (S) volumes must be reported in long tons (2,240 pounds).

PART 206—PRODUCT VALUATION

8. The authority citation for part 206 is revised 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.*.

Subpart D [Revised]

9. The heading of subpart D is revised to read "Indian Gas."

§ 206.150 [Amended]

10. Section 206.150 is amended by removing the words "Federal and" from paragraph (a); removing paragraph (e)(1); redesignating paragraph (e)(2) as paragraph (e)(1); redesignating paragraph (e)(3) as paragraph (e)(2); and by removing paragraph (e)(4).

11. Section 206.151 is amended by removing the words "Federal and" from the definition of *Audit*; removing the third sentence from the definition of *Field*; removing the words "Federal or" from the fourth sentence of the definition of *Gross proceeds*; removing the words "Outer Continental Shelf or onshore Federal or" from the definition of *Lease products;* removing the words "Federal and" from the definition of *Net profit share*; removing the definitions of *Outer Continental Shelf (OCS)* and *Section 6 lease*; and by adding two new sentences at the end of the definition of *Lease* as set forth below.

§ 206.151 Definitions.

* * * * *

Lease * * * For purposes of this subpart, this definition excludes Federal leases. However, where the term *lease* is used in reference to an agreement, this term may refer to non-Indian leases (e.g., Federal leases, State leases, or fee leases) where the context requires.

§ 206.152 [Amended]

12. Section 206.152 is amended by removing the words "Federal or" from paragraph (e)(2).

§ 206.153 [Amended]

13. Section 206.153 is amended by removing the words "Federal or" from paragraph (e)(2).

§ 206.154 [Amended]

14. Section 206.154 is amended by removing the words "or MMS for onshore and OCS leases, respectively" from paragraph (a)(1); and by removing the words "Federal and" from the second sentence of paragraph (c)(4).

§ 206.157 [Amended]

15. Section 206.157 is amended by removing the words "(for both Federal and Indian leases)" and "or a State regulatory agency (for Federal leases)" from the second sentence in paragraph (b)(5); removing the words "For lessees transporting production from onshore Federal and Indian leases," from paragraph (e)(2); and by removing paragraph (e)(3).

§ 206.159 [Amended]

16. Section 206.159 is amended by removing the words "For lessees processing production from onshore Federal and Indian leases," from paragraph (e)(2); and by removing paragraph (e)(3).

17. A new Subpart J is added as follows:

Subpart J—Federal Gas

Sec.

Subpart J—Federal Gas

§ 206.450 Purpose and scope.

(a) This subpart is applicable to all gas production from Federal oil and gas leases. 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 Indian leases.

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

(c) All royalty payments made to MMS are subject to audit and adjustment.

§ 206.451 Definitions.

For purposes of this subpart:

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 zone.

Agreement means a federally-approved unit or communitization agreement.

Allowance means a deduction in determining value for royalty purposes. *Processing allowance* means an allowance for the reasonable costs for processing gas determined under this subpart. *Transportation allowance* means an allowance for the cost of moving royalty bearing substances (identifiable, measurable oil and gas, including gas that is not in need of initial separation) from the point at which it is first identifiable and measurable to the sales point or other point where value is established under this subpart.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

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.

(1) For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

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

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

(iii) 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.

(2) 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 ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

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

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.

Entitlement (or entitled share) means, for leases in an agreement, the gas production allocable to lease acreage under the agreement terms, multiplied by the operating rights owner's percentage of interest ownership in that acreage.

Facility measurement point (or point of royalty settlement) means the point at which the measurement device is located that was approved by MMS or BLM for determining the volume of gas removed from the lease.

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. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by MMS.

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

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

Gathering means the movement of an unseparated, bulk production stream to a point, on or off the lease, where the production stream undergoes initial separation into identifiable oil, gas, or free water.

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, or gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as compression, dehydration, measurement, and/or field gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government, 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 Federal royalty interest may be 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 the first point on any pipeline connected to a well which is a single connect or split connect for which there is an index. For a multiple connection, it means the first point on each pipeline segment after the pipeline connected to the well splits for which there is an index.

Jurisdictional pipeline means a pipeline with a rate regulated and approved by the Federal Energy Regulatory Commission (FERC) or a state agency.

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 Indian leases. However, where the term ''lease'' is used in reference to an agreement, the term may refer to non-Federal leases (*e.g.* Indian leases, State leases, or fee leases) where the context requires.

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

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

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

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

Marketing affiliate means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

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

Mixed agreement means an agreement that includes leases other than only Federal leases with the same royalty rate and fund distribution.

Multiple connection means a situation where one pipeline is connected to the well, platform, central delivery point, or plant, but that pipeline splits prior to an IPP or IPP's.

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

Net-back method (or work-back method) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from 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, to ascertain value at the lease.

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.

Non-jurisdictional pipeline means a pipeline with no rates regulated or approved by Federal Energy Regulatory Commission (FERC) or a state agency.

Operating rights owner (working interest owner) means a 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) and MMS regulations at 30 CFR 256.62).

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. § 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Percentage-of-proceeds contract means a contract for the sale of gas prior to processing which provides for the consideration to be determined based upon a percentage of the purchaser's proceeds resulting from processing and selling the gas and the gas plant products.

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

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

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

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

Section 6 lease means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

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.

Single connect means a situation where only one pipeline is connected to the well, platform, central delivery point, or plant, and that pipeline does not split prior to an IPP.

Small operating rights owner is a person who produces less than 6,000 Mcf/day total U.S. gas production at 14.73 pounds per square inch absolute (psia) at 60 °F *and* less than 1,000 bbls/day total U.S. oil production at 60 °F.

Split connect means a situation where more than one pipeline connects to the well, platform, central delivery point, or plant prior to or at the IPP or IPP's.

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, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor 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.

Zone means a geographic area containing blocks or fields as defined by MMS.

§ 206.452 Valuation standards—unprocessed gas.

(a)(1) This section applies to the valuation of gas that is not processed and gas that is processed but is sold or otherwise disposed of by the lessee under an arm's-length contract prior to processing (including gas sold under an arm's-length percentage-of-proceeds contract). Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, § 206.453 of this subpart will apply instead of this section.

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

(3) For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate must be valued depending on how the marketing affiliate resells the gas.

(b)(1)(i) The value of gas sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (iii) of this section, and except as provided in § 206.454 of this subpart to the extent that section applies to gas sold under an arm's-length contract that is not dedicated. The lessee will have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. Also, for arm's-length percentage-of-proceeds contracts, the value of production, for royalty purposes, must never be less than a value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits for gas valued based upon gross proceeds under this paragraph, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then MMS may require that the gas sold under that contract be valued in accordance with paragraphs (c) (2) or (3) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If MMS determines for gas valued under this paragraph that the gross proceeds accruing to the lessee under an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS will require that the gas production be valued under paragraphs (c) (2) or (3) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) If gas is not sold under an arm's-length contract, the lessee must first determine whether the gas is subject to valuation under § 206.454. If that section is applicable, the lessee must use it to value the production. For gas not subject to valuation under that section and for other gas that must be valued under this paragraph, the value of gas must be the first applicable of the following:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (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). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

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

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

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

(2) Any Federal lessee will make available upon request to the authorized MMS or state representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(e) If MMS determines that a lessee has not properly determined value, the lessee must pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee must also pay interest on that difference computed under 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee must propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee must submit all available data relevant to its proposal. MMS will expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination will remain effective for the period stated therein. After MMS issues its determination, the lessee must make the adjustments in accordance with paragraph (e) of this section.

(g) For gas valued under this section (but not for any gas valued using an index-based method under § 206.454), under no circumstances may the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined under this subpart.

(h) The lessee is required to place gas in marketable condition at no cost to the Federal Government unless otherwise provided in the lease agreement. Where the value established under this section is determined by a lessee's gross proceeds, that value must be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

(i) For gas valued under this section (but not for any gas valued using an index-based method under § 206.454), value must be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it 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 the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph may not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

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

(k) Certain information submitted to MMS to support valuation proposals, including transportation or extraordinary cost 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 law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

§ 206.453 Valuation standards—processed gas.

(a)(1) This section applies to the valuation of gas that is processed by the lessee (including gas where the lessee has an agreement with a gas processing plant that provides for the retention of the gas plant products by the plant owner and for the payment, in kind or in value, to the lessee for the plant thermal reduction). This section also applies to any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 206.452 of this subpart, including situations where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, is the combined value of the residue gas and all gas plant products determined under this section, plus the value of any drip condensate determined under this part, less applicable transportation allowances and processing allowances determined under this part. No processing allowance is applicable to any gas plant products valued under § 206.454.

(3) For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate must be valued depending on how the marketing affiliate resells the gas.

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section, and except as provided in § 206.454 of this subpart to the extent that section applies. The lessee will have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit.

(ii) In conducting these reviews and audits for gas valued based upon gross proceeds under this paragraph, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then MMS may require that the residue gas or gas plant product sold under that contract be valued in accordance with paragraph (c) (2) or (3) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

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

(2) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) If residue gas or any gas plant product is not sold under an arm's-length contract, the lessee must first determine whether the residue gas or gas plant product is subject to valuation under § 206.454. For residue gas subject to valuation under § 206.454, the lessee must use that section to value the residue gas. For residue gas or any gas plant product not subject to valuation under that section and for other residue gas and gas plant products that must be valued under this paragraph, the value must be the first applicable of the following:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (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 residue gas or gas plant products 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 shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of 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 residue gas or gas plant products; or

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

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

(2) Any Federal lessee will make available upon request to the authorized MMS or state representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(e) If MMS determines that a lessee has not properly determined value, the lessee must pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee must also pay interest computed on that difference under 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee must propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee must submit all available data relevant to its proposal. MMS will expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination will remain effective for the period stated therein. After MMS issues its determination, the lessee must make the adjustments in accordance with paragraph (g) of this section.

(g) For residue gas and gas plant products valued under this section (but not for residue gas or gas plant products valued under §§ 206.454(a)(2)(i), (ii)(A), (iii) or (iv)), under no circumstances may the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined under this subpart.

(h) The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Federal Government unless otherwise provided in the lease agreement. Where the value established under this section is determined by a lessee's gross proceeds, that value must be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition.

(i) For residue gas and gas plant products valued under this section (but not for any residue gas or gas plant product valued using an index-based method under § 206.454), 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 the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it 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 the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph may not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

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

(k) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost 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 law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

§ 206.454 Alternative valuation standards for unprocessed gas and processed gas.

(a) *Applicability*. This section provides an alternative method to value for royalty purposes unprocessed gas and processed gas produced from Federal leases. However, it does not apply to unprocessed gas or residue gas sold under a dedicated arm's-length contract. It also does not establish value for carbon dioxide, nitrogen, or other non-Btu components of the gas stream. This section applies only to gas production from leases that are in zones with an active spot market and published indices acceptable to MMS under paragraph (d) of this section and to deepwater OCS leases whether or not in a zone. If the production does not qualify for valuation under this section, then the lessee must value its production under §§ 206.452 or 206.453, as applicable.

(1)(i) For unprocessed gas subject to this section that is sold under an arm's-length contract that is not dedicated, the lessee may elect to value the gas using an index-based method under this section. If the lessee does not elect to use this section, then the requirements of § 206.452(b)(1) apply.

(ii) For unprocessed gas subject to this section not sold under an arm's-length contract, the lessee must value the gas using either:

(A) an index-based method under this section; or

(B) the gross proceeds (determined under § 206.452) accruing to the lessee's affiliated purchaser, but only if the affiliated purchaser is not a marketing affiliate and it sells the gas under an arm's-length contract.

(2)(i) For residue gas subject to this section that is sold under an arm's-length contract that is not dedicated, the lessee may elect to value the gas using an index-based method under this section. If the lessee does not elect to use this section, then the requirements under § 206.453(b)(1) apply.

(ii) For residue gas subject to this section that is not sold under an arm's-length contract, the lessee must value the gas under this section using either:

(A) an index-based value under this section; or

(B) the gross proceeds (determined under § 206.453) accruing to the lessee's affiliated purchaser, but only if the affiliated purchaser is not a marketing affiliate and it sells the residue gas under an arm's-length contract.

(iii) If the lessee values residue gas under paragraph (a)(2) of this section using an index-based method, then the lessee may elect to value the NGL's, elemental sulfur, and drip condensate associated with that residue gas using the same index-based value per MMBtu used to value the associated residue gas, including any transportation allowance under § 206.457 applicable to the residue gas. If the lessee does not elect to use the index-based method, the provisions of §§ 206.453(b) or (c), as applicable, apply to value those products.

(iv) If the lessee values the residue gas under an arm's-length contract that is not dedicated using § 206.453(b), or if it values the residue gas using its affiliated purchaser's arm's-length gross proceeds under paragraph (a)(2)(ii)(B) of this section, then the lessee may elect to value the NGL's, elemental sulfur, and drip condensate associated with that residue gas using the same price per MMBtu used to value the associated residue gas, including any transportation allowance under § 206.457 applicable to the residue gas. If the lessee does not elect to use this alternative value, the provisions of §§ 206.453(b) or (c), as applicable, apply.

(3) A lessee may use the alternative valuation methods provided under paragraphs (a)(1) and (a)(2) of this section only if:

(i) There is an active spot market for the gas to be valued; and

(ii) The gas flows or could flow through at least one pipeline with at least one published index price in the zone; and

(iii) For all leases in a zone or each OCS deepwater lease:

(A) all unprocessed gas and residue gas subject to this section that is sold under an arm's-length contract that is not dedicated is valued using the same valuation method under this section; and

(B) all unprocessed gas and residue gas subject to this section that is not sold under an arm's-length contract is valued using the same valuation method under this section where the lessee has an election; and

(C) all NGL's, elemental sulfur, and drip condensate associated with residue gas valued under paragraph (a)(2) of this section using an index-based method is valued using the same valuation method; and

(D) all NGL's, elemental sulfur, and drip condensate associated with residue gas valued under paragraphs (a)(2)(i) and (a)(2)(ii)(B) of this section using a gross proceeds based method is valued using the same valuation method; and

(iv) The lessee uses the valuation method elected for at least 2 calendar years.

(v) Any alternative value election under paragraphs (a)(1) and (a)(2) of this section is subject to adjustment as provided in paragraph (e) of this section.

(4) If the lessee does not satisfy all the criteria under paragraph (a)(3) of this section, the value of the unprocessed gas or processed gas must be determined under §§ 206.452 or 206.453 of this subpart, as applicable.

(5) Any production in the zone that the lessee adds during the two year election period must be valued for the remainder of the period using the same method as for the lessee's other production in the zone sold under similar circumstances.

(6) If the lessee receives or received any revenue in connection with the reformation or termination of any gas purchase contract that occurred prior to effective date of this rule associated with production from a Federal lease, those revenues may be subject to royalty in accordance with the Department's existing precedents at the time a part of such revenue is attributed to later production. If so, royalty will be due on the increment of revenue attributed to future production in addition to any index-based or other value established under this section.

(b) *Index-based valuation.* The value of gas from a well on a lease for any month determined by using an index-based method under this section is the index value. Calculation of the index value depends upon whether the gas flows or could flow through a single connect, a split connect, or multiple connection as follows:

(1) For a single connect, the index value is the index price for the first IPP. The index value must be used for that month to value the gas production from the well.

(2) For a split connect or a multiple connection, the lessee must elect one of the two following options to determine the index value. The index value so determined must be used for that month to value the gas production from the well.

(i) *Weighted-Average Index Value.* The weighted-average index value for the month is calculated by:

(A)(*1*) multiplying the volume of the lessee's gas actually flowing from a well to each IPP by the applicable index price for that IPP determined using the publication selected under paragraph (d) of this section;

(*2*) adding the numbers for each IPP determined under paragraph (b)(2)(i)(A)(*1*) of this section; and

(*3*) dividing that sum by the total volume of the lessee's gas actually flowing to all IPP's. The resulting quotient is the index value for gas production from the well for that month.

(B) For purposes of paragraph (b)(2)(i) of this section, the amount of gas actually flowing to each IPP is determined by using the nominations confirmed at the first of the month or the total nominations confirmed during the month, applied consistently for the two-year election period. If the actual flow of the gas during the month is different from the flow determined by the confirmed nominations used to calculate the value under this paragraph, the weighted average index value will not be recalculated using the actual flow volume.

(ii) *Fixed Index Value.* (A) The fixed index value for the month is determined as follows: for each of the IPP's through which gas from a well flows or could flow, determine the average of the applicable monthly index prices for the previous calendar year published in the publication selected for each of those IPP's under paragraph (d) of this section. List the average price determined for each IPP from highest at the top to lowest at the bottom. If there are only two IPP's, select the IPP associated with the first average index price starting from the top of the list. The selected IPP will be used for the entire calendar year. The index price for the current month in the current year's publication selected for that IPP is the index value for all gas production from the well for that month. If there are three or more IPP's, select the IPP associated with the second average index price starting from the top of the list. The selected IPP will be used for the entire calendar year. The index price for the current month in the current year's publication selected for that IPP is the index value for all gas production from the well for that month.

(B) The result of the calculation in preceding paragraph (A) may be that the selected average index price (either the highest average index price if there are only two IPP's, or the second highest if there are more than two IPP's) is identical to another index price in the array. In that event, the lessee must recalculate the average of the applicable monthly index prices for the previous calendar year for each IPP to eight decimal points and redetermine the selected average index price and the corresponding publication in accordance with preceding paragraph (b)(2)(ii)(A) of this section. If the selected average index price still is identical to another average index price, the lessee may choose either one.

(C) The transportation allowance provided under § 206.457 may not be included in the calculation under either preceding paragraphs (b)(2)(ii) (A) or (B) of this section.

(iii) *Election*. To determine the index value for a split connect or multiple connection situation, the lessee must elect to use the weighted-average index value or the fixed index value for the same two year period as elected under paragraph (a)(3)(iv) of this section. The elected method must be applied to all of the lessee's gas subject to valuation under this section produced from wells that are connected for the same split connect or multiple connection. Therefore, for example, within the same zone, the lessee may elect the weighted-average index value for production from wells connected to one multiple connection, and the fixed index value for production from wells connected to a different multiple connection. The election to use either the weighted-average index value or the fixed index value must be made at the same time the lessee elects to use an index-based method under paragraph (a) of this section.

(c) *Transportation allowance.* As provided under § 206.456, a transportation allowance may be deducted from the index-based value determined under this section for the costs that are, or would be, incurred to transport the gas to the IPP(s).

(d) *Acceptable publications.* At the beginning of each calendar year for which the lessee elects to use an index-based method to value production from a well under paragraph (a) of this section, the lessee must select a publication that meets MMS-established criteria for acceptability for each applicable IPP to determine the associated index price. If more than one publication publishes an index price at an applicable IPP, the lessee must select one of the acceptable publications to use during that calendar year.

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

(i) Publications frequently used by buyers and sellers,

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

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

(iv) Publications independent from lessees and MMS.

(2) Any publication may petition MMS to be added to the list of acceptable publications provided the publication meets the criteria under paragraph (d)(1) of this section.

(3) MMS will reference which tables in the publications must be used for determining IPP's and associated index prices.

(4) MMS will publish the IPP's that it considers common among acceptable publications.

(5) For single connects:

(i) If an acceptable publication publishes a new IPP that qualifies as the first IPP, the lessee must use that IPP beginning with the first day of the month the new IPP is published;

(ii) If the lessee's selected publication eliminates the IPP the lessee is using, the lessee must select another publication for that IPP beginning with the first day of the month the IPP is eliminated;

(iii) If the IPP the lessee is using is eliminated from all acceptable publications, the lessee must determine a new IPP at the first pipeline interconnect to which the gas flows or could flow beginning with the first day of the month the original IPP is eliminated.

(6) For a split connect or a multiple connection where the lessee elects to use the weighted-average index value:

(i) If an acceptable publication adds a new IPP to which the lessee's gas flows, the lessee must begin using the new IPP beginning with the first day of the month the new IPP is added;

(ii) If any of the lessee's selected publications eliminates an IPP to which the lessee's gas flows, the lessee must select another acceptable publication for that IPP beginning with the first day of the month the IPP is eliminated;

(iii) If an IPP to which the lessee's gas flows is eliminated from all acceptable publications, the lessee may not use that volume in the weighted-average index value calculation beginning with the first day of the month the IPP is eliminated, unless another IPP is downstream of the original IPP.

(7) For a split connect or a multiple connection where the lessee elects to use the fixed index value:

(i) If an acceptable publication adds a new IPP, that IPP must not be used in determining the fixed index value until the following calendar year;

(ii) If the lessee's selected publication eliminates an IPP the lessee was using, the lessee must select another acceptable publication for that IPP beginning with the first day of the month the IPP is eliminated.

(iii) If the IPP the lessee was using is eliminated from all acceptable publications, the lessee must exclude that IPP and determine a new IPP under paragraph (b)(2)(ii) of this section beginning with the first day of the month the original IPP is eliminated.

(e) *Additional royalty obligations.* Under paragraphs (e)(8), (e)(9), and (e)(10) of this section, the weighted average of the alternative values determined under this section by the lessee in a zone for the calendar year, less applicable transportation allowances, must be compared to the final safety net median value calculated for the zone under this paragraph. If the lessee's weighted-average value is less than the final safety net median value, the lessee must pay additional royalties under paragraphs (e)(8), (e)(9), or (e)(10) of this section, as applicable. If the lessee's weighted-average value for the zones less applicable transportation allowances under § 206.457 equals or exceeds the final safety net median value, royalty will be based on the lessee's weighted-average value for the zone.

(1) MMS will use, to the extent possible, the following information reported on Form MMS–2014 for leases in a zone for the calendar year to calculate the final safety net median value. The lines of information from the Form MMS–2014 described in the following paragraphs (e)(1)(i)–(iv) of this section are the final reported transactions existing at the time the final safety net median value is calculated 2 years following the end of the calendar year:

(i) Lines reporting royalty due (Transaction Code 01 or 06) for unprocessed gas (Product Code 04) and residue gas (Product Code 03) where the sales value represents values based on gross proceeds under the following sales transactions:

(A) Arm's-length dedicated sales;

(B) Arm's-length non-dedicated sales, but only if the associated gas plant products are valued under § 206.453;

(C) Arm's-length resales by the lessee's affiliated purchaser, but only if the associated gas plant products are valued under § 206.453;

(D) Federal royalty-in-kind gas sales for the applicable zone.

(ii) Lines reporting royalty due (Transaction Code 01) for drip condensate (Product Code 05), natural gas liquids (Product Code 07), and elemental sulfur (Product Code 19) associated with the residue gas reported on the lines in paragraph (e)(1)(i) of this section.

(iii) Lines reporting transportation allowances (Transaction Code 11) associated with any product reported on the lines in paragraphs (e)(1)(i) and (ii) of this section.

(iv) Lines reporting processing allowances (Transaction Code 15) associated with NGL's and sulfur reported on the lines in paragraph (e)(1)(ii) of this section.

(2) MMS will also use the following information related to the calendar year's production to calculate the final safety net median value:

(i) Unappealed orders for additional royalties;

(ii) Unappealed MMS Director's decisions involving orders for additional royalties;

(iii) Refunds from requests under Section 10 of the OCS Lands Act of 1953, 43 U.S.C. § 1339; and

(iv) Amounts from MMS Director's decisions pending in administrative or judicial actions.

(v) If any monetary amounts under paragraphs (e)(1)(i)–(iv) of this section are not reported on a Form MMS–2014, MMS will convert the amounts to an appropriate rate per MMBtu for use under paragraph (e)(1) of this section.

(3) The final safety net median value will not include:

(i) Lines reporting royalties paid on pipeline buyout or buydown settlement amounts (Transaction Code 31);

(ii) Unpaid issue letters (preliminary determination letters); or

(iii) Appealed orders not yet decided by the MMS Director.

(4) The final safety net median value for a zone is calculated by arraying the

prices per MMBtu derived from the information under paragraphs (e)(1) and (2) of this section from highest to lowest (at the bottom). The final safety net median value is that price at which 50 percent plus 1 MMBtu of the production (starting from the bottom) is sold.

(5) The final safety net median value must be based on a representative sample as provided in paragraph (f) of this section.

(6) MMS will publish in the Federal Register the final safety net median value within two years following the end of the calendar year.

(7) A lessee may request a technical procedural review from the Associate Director for Royalty Management of the final safety net median value after it is published. All affected parties will be given an opportunity to participate in the review process. Following the technical procedural review, the Associate Director may modify the final safety net median value. The Associate Director's decision following the technical procedural review will be completed in an expeditious manner and will be a final Departmental decision not subject to further administrative review.

(8) This paragraph applies to a lessee's unprocessed gas and residue gas produced from leases in a zone which is valued using an index-based method under this section, but only for that residue gas where the associated gas plant products are valued under § 206.453 and not under this section. The lessee must determine the weighted-average index-based value for unprocessed gas and residue gas in the zone by summing the index-based values determined under this section, less applicable transportation allowances under § 206.457, and dividing that sum by the total quantity of MMBtu's of unprocessed gas and residue gas in the zone. If that weighted-average index-based value is less than the final safety net median value for the zone, the lessee must pay additional royalties, plus interest, as follows:

(i) For the first calendar year this section is in effect, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Determine the lesser of the final safety net median value or 105 percent of the lessee's weighted-average index-based value determined in preceding paragraph (e)(8);

(B) Subtract the weighted-average index-based value from the lesser value under preceding paragraph (e)(8)(i)(A) of this section;

(C) Multiply the difference by the lessee's royalty quantity for all unprocessed gas and residue gas in the zone subject to this paragraph, converted to MMBtu's.

(ii) For subsequent calendar years, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Subtract the lessee's weighted-average index-based value determined under preceding paragraph (e)(8) from the final safety net median value;

(B) Multiply the difference by 50 percent;

(C) Multiply the result by the lessee's royalty quantity for all unprocessed gas and residue gas in the zone subject to this paragraph, converted to MMBtu's.

(iii) Late payment interest will accrue on any underpaid royalties in accordance with paragraph (e)(12) of this section.

(9) This paragraph applies to a lessee's residue gas, NGL's, elemental sulfur, and drip condensate produced from leases in a zone which are valued using an index-based value determined under this section. The lessee must determine the weighted-average index-based value of that residue gas and associated products in the zone by summing the index-based values determined under this section, less applicable transportation allowances under § 206.457, and dividing that sum by the total quantity of MMBtu's of that residue gas and associated products in the zone. If that weighted-average index-based value is less than the final safety net median value for the zone, the lessee must pay additional royalties, plus interest, as follows:

(i) For the first calendar year this section is in effect, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Determine the lesser of the final safety net median value or 105 percent of the lessee's weighted-average index-based value determined under preceding paragraph (e)(9);

(B) Subtract the weighted-average index-based value from the lesser value under preceding paragraph (e)(9)(i)(A) of this section;

(C) Multiply the difference by the lessee's royalty quantity for all residue gas and associated products in the zone subject to this paragraph, converted to MMBtu's.

(ii) For subsequent calendar years, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Subtract the lessee's weighted-average index-based value determined under preceding paragraph (e)(9) from the final safety net median value;

(B) Multiply the difference by 50 percent;

(C) Multiply the result by the lessee's royalty quantity for all residue gas and associated products in the zone subject to this paragraph, converted to MMBtu's.

(iii) Late payment interest will accrue on any underpaid royalties in accordance with paragraph (e)(12) of this section.

(10) This paragraph applies to a lessee's residue gas, NGL's, elemental sulfur, and drip condensate produced from leases in a zone which are valued using the lessee's or the lessee's affiliated purchaser's gross proceeds for residue gas determined under §§ 206.453(b) or 206.454(a)(2)(ii)(B) of this subpart, as applicable. The lessee must determine the weighted-average value of that residue gas and associated products in the zone by summing the gross proceeds-based values determined under §§ 206.453(b) or 206.454(a)(2)(ii)(B), less applicable transportation allowances under § 206.457, and dividing that sum by the total quantity of MMBtu's of that residue gas and associated products in the zone. If the resulting weighted-average gross proceeds-based value is less than the final safety net median value for the zone, the lessee must pay additional royalties, plus interest, as follows:

(i) For the first calendar year this section is in effect, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Determine the lesser of the final safety net median value or 105 percent of the lessee's weighted-average gross proceeds-based value determined under preceding paragraph (e)(10);

(B) Subtract the weighted-average gross proceeds-based value from the lesser value under preceding paragraph (e)(10)(i)(A) of this section;

(C) Multiply the difference by the lessee's royalty quantity for all residue gas and associated products in the zone subject to this paragraph, converted to MMBtu's.

(ii) For subsequent calendar years, the additional royalty payment for production subject to this paragraph is calculated as follows:

(A) Subtract the lessee's weighted-average gross proceeds-based value determined under preceding paragraph (e)(10) from the final safety net median value;

(B) Multiply the difference by 50 percent;

(C) Multiply the result by the lessee's royalty quantity for all residue gas and associated products in the zone subject to this paragraph, converted to MMBtu's.

(iii) Late payment interest will accrue on any underpaid royalties in accordance with paragraph (e)(12) of this section.

(11) For each deepwater lease on the Outer Continental Shelf, the additional royalty due under paragraphs (e)(8), (e)(9), and (e)(10) of this section will be calculated by deducting from the applicable safety net median value the appropriate transportation allowance to the first point within a zone to which production from that lease flows.

(12)(i) As soon as possible following the end of each calendar year (preferably within 6 months), MMS will publish an initial safety net median value for each zone. The initial safety net median value will be calculated using the methodology in paragraph (e)(4) of this section and using the information listed in paragraph (e)(1) of this section available at the time of its calculation, even if that information is not final.

(ii) The lessee may submit an estimated payment for any additional royalty it determines is due because of the difference between the lessee's weighted-average value determined under this section and the initial safety net median value. If the final safety net median value published under paragraph (e)(6) of this section is lower than the initial safety net median value, the lessee is entitled to a credit or refund of all or a portion of its estimated payment without interest under paragraph (e)(12)(iii) of this section.

(iii) After publication of the initial safety net median value or the final safety net median value, the lessee may report additional royalty payments using a one-line entry on Form MMS–2014 for each zone. If the lessee files a Form MMS–2014 and makes an estimated payment of additional royalty after publication of the initial safety net median value, then following publication of the final safety net median value it must file an amended Form MMS–2014 adjusting any payments for each zone, if necessary. On this amended Form MMS–2014, the lessee may recoup any overpayment by filing a credit adjustment. This first credit adjustment is not subject to the requirements of section 10 of the Outer Continental Shelf Lands Act, 43 U.S.C. 1339. Any subsequent credit adjustment for a zone is subject to section 10.

(iv) Late payment interest will not accrue on any additional royalty owed under paragraphs (e)(8), (e)(9), or (e)(10) of this section until the date MMS publishes the initial safety net value.

(f) *Representative sample.* The final safety net median value must be based on a representative sample, which, for purposes of this section, means at least ten percent of the MMBtu of production reported to MMS on Form MMS–2014 for leases in a zone under paragraphs (e)(1) (i) and (ii) of this section, or at least twenty percent of the lines reported to MMS on Form MMS–2014 for leases in a zone under paragraphs (e)(1) (i) and (ii) of this section. If a representative sample meeting these criteria is not available at the time MMS is required to calculate the initial safety net median value under paragraph (e)(12) of this section, MMS will use the following procedures to obtain an appropriate sample:

(1) Among lessees in the zone using an index-based method to value production under this section, MMS will ask for volunteers to provide access to their records (including records regarding affiliated purchasers' resale values) to obtain arm's-length gross proceeds volume and value information. MMS will take a stratified sample of this information to be added to the information reported on Form MMS–2014 based on arm's-length gross proceeds under paragraphs (e)(1) (i) and (ii) of this section to determine the final safety net median value for the zone.

(2) If there are no volunteers in the zone, or not enough information from the volunteers to fulfill the requirements of a representative sample, MMS will establish the final safety net median value. Actions that MMS will take to determine the final safety net median value will include, but not be limited to, issuing orders to lessees within the zone necessary to obtain sufficient gross proceeds data to develop the final safety net median value for the zone.

(3) Lessees that volunteer to provide access to their records under this paragraph will have any additional royalty obligation determined under paragraphs (e)(8), (e)(9), or (e)(10) of this section based upon the lesser of a negotiated value or a calculation under those paragraphs using the final safety net median value reduced by $0.005/MMBtu.

(g) *Zone determination.* (1) MMS will publish in the Federal Register the zones with an active spot market and published indices that are eligible for an index-based valuation method. MMS will use the following factors and conditions in determining eligible zones:

(i) Common markets served;

(ii) Common pipeline systems;

(iii) Simplification; and

(iv) Easy identification in MMS' system, such as offshore blocks, offshore areas, or onshore counties.

(2) Deepwater leases in the OCS will not be included in a zone that includes non-deepwater leases.

(3) MMS will monitor the market activity in the zones and, if necessary, hold a technical conference to add or modify a particular zone. Any change to the zones will be published in the Federal Register.

(h) *Zone disqualification.* If market conditions change so that an index-based method for determining value is no longer an appropriate measure of market value for a zone, MMS will hold a technical conference to consider disqualification of a zone. MMS will publish notice in the Federal Register of a zone disqualification. However, MMS will not disqualify a zone prior to the end of the calendar year. MMS will notify lessees by September 1 of the year prior to disqualification.

§ 206.455 Determination of quantities and qualities for computing royalties.

(a)(1) Royalties must be computed on the basis of the quantity and quality of unprocessed gas at the facility measurement point approved by BLM or MMS for onshore and OCS leases, respectively.

(2) If the value of gas determined under § 206.452 of this subpart is based upon a quantity and/or quality that is different from the quantity and/or quality at the facility measurement point, as approved by BLM or MMS, that value must be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined under § 206.453 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value must be adjusted for the differences in quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease must be determined according to the following procedure:

(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 computations of royalty are based 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 nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Federal leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the facility measurement point will not be subject to royalty provided that such loss is determined to have been unavoidable by BLM or MMS, as appropriate.

(2) Except as provided in paragraph (d)(1) of this section and 30 CFR 202.451(c) of this part, royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

§ 206.456 Transportation allowances—general.

(a)(1) Where the value of gas has been determined under this subpart at a point off the lease (*e.g.*, sales point, IPP, or other point of value determination), the lessee may deduct from value a transportation allowance to reflect the value, for royalty purposes, at the lease. For residue gas and gas plant products, the lessee may deduct a transportation allowance representing the reasonable costs of transporting the residue gas and gas plant products to a gas processing plant off the lease and from the plant to a point away from the plant. If gas flows or could flow through more than one pipeline segment to the point where value is determined, the transportation allowance will be based on the total allowances for each segment determined under § 206.457.

(2) For the purposes of this subpart, the lessee's costs of compression downstream of the facility measurement point incurred either by the payment of such cost under a contract or the performance of that function may be a part of the lessee's transportation allowance determined under § 206.457 of this subpart. However, under no circumstances may any costs of compression occurring prior to the facility measurement point be deductible. The lessee's costs of boosting or compressing residue gas after processing are part of the transportation allowance for residue gas.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 206.457 of this subpart.

(c)(1) Except as provided in paragraph (c)(2) of this section, the transportation allowance deduction on the basis of a selling arrangement must not exceed 50 percent of the value of the unprocessed gas, residue gas, or gas plant products determined under § 206.452, § 206.453, or § 206.454 of this subpart, as applicable. For purposes of this section, NGL's must be considered one product.

(2) Upon request of a lessee, MMS may approve an exception for a transportation allowance deduction in excess of the limitations prescribed by paragraph (c)(1) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraph (c)(1) of this section were reasonable and necessary. An application for exception must contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances may the value for royalty purposes under any selling arrangement be reduced to zero.

(3) Notwithstanding any other provision of this subpart, MMS may approve, upon request of the lessee, a transportation allowance for the movement of gas from deepwater OCS leases, even if the production from the lease has not been initially separated.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee must pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54, or will be entitled to a credit, without interest.

§ 206.457 Determination of transportation allowances.

(a) *Introduction.* This section explains how to determine the applicable transportation allowance. If the lessee uses gross proceeds to value its production, then the transportation allowance is based on the transportation costs under paragraphs (b) or (c) of this section, depending upon whether the pipeline is jurisdictional or non-jurisdictional, and whether the transportation contract is arm's-length. If the lessee uses an index-based method to value its production, *and if* a portion of the lessee's gas flows to the IPP used for value, then, as provided in paragraph (d) of this section, the transportation allowance is based on the transportation costs under paragraphs (b) or (c) of this section, as applicable. If the lessee uses an index-based method to value its production, but *none* of its gas flows to the IPP used for value, the transportation allowance is determined under paragraph (d)(5) of this section.

(b) *Jurisdictional pipelines and arm's-length transportation contracts for non-jurisdictional pipelines.* (1)(i) For all value determinations under § 206.452, § 206.453, § 206.454(a)(1)(ii)(B), or § 206.454(a)(2)(ii)(B) of this subpart, where the lessee or its affiliate actually transports unprocessed gas, residue gas, gas plant products, or drip condensate through a jurisdictional pipeline, the transportation allowance must be based on the reasonable, actual contract rate paid in accordance with this paragraph.

(ii) For all value determinations under § 206.452, § 206.453, § 206.454 (a)(1)(ii)(B), or § 206.454(a)(2)(ii)(B) of this subpart, where the lessee or its affiliate actually transports unprocessed gas, residue gas, gas plant products, or drip condensate through a non-jurisdictional pipeline under an arm's-length transportation contract, the transportation allowance must be based on the reasonable, actual contract rate paid in accordance with this paragraph.

(2)(i) In conducting reviews and audits, MMS will examine whether or not the actual contract rate paid reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract rate paid reflects more than the total consideration, then MMS may require that the transportation allowance be determined in accordance with paragraph (c)(2) of this section.

(ii) If MMS determines that the actual contract rate paid does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS will require that the transportation allowance be determined in accordance with paragraph (c)(2) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(3)(i) If a 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 in the same proportion as the ratio of the volume of each product to the volume of all products in the gaseous phase. No allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (b)(3)(i) of this section, the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) If a transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee must propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee must submit all relevant data to support its proposal. MMS will then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(5) Where the lessee's payments for transportation under a contract are not based on a dollar per unit, the lessee must convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(6) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's (or affiliate's, as the case may be) gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(7) MMS may require that a lessee submit transportation contracts, production agreements, operating agreements, and related documents. Documents must be submitted within a reasonable time as determined by MMS.

(c) *Non-jurisdictional pipelines—non-arm's-length transportation.* (1) For all value determinations under § 206.452, § 206.453, § 206.454(a)(1)(ii)(B), or § 206.454(a)(2)(ii)(B) of this subpart, the transportation allowance for a non-jurisdictional pipeline under either a non-arm's-length transportation contract or no contract must be determined as follows:

(i) If 30 percent or less of the gas in the pipeline is transported under arm's-length transportation contracts, the transportation allowance for a calendar year must be based on either:

(A) The lessee's reasonable, actual costs as provided under paragraph (c)(2) of this section; or

(B) A rate of $0.02/MMBtu for leases on the Outer Continental Shelf; for onshore leases a *de minimis* rate determined by MMS for onshore leases not to exceed $0.09/MMBtu, including pipeline fuel consideration. MMS periodically will establish the rate based upon available transportation cost data and will publish the applicable rate in the Federal Register.

(ii) If more than 30 percent of the gas in the pipeline is transported under arm's-length transportation contracts, the transportation allowance for a calendar year must be based on either:

(A) The lessee's reasonable, actual costs as provided under paragraph (c)(2) of this section; or

(B) A rate determined by arraying all of the arm's-length contract rates for the pipeline from highest at the top to lowest at the bottom and starting from the bottom, choosing the rate closest to the 25th percentile from the bottom. If two of the contract rates are equidistant from the 25th percentile, use the average of the two rates.

(2) This paragraph applies to non-arm's-length and no contract transportation situations where the lessee elects to determine its transportation allowance based upon its actual costs. Under this paragraph, the lessee's reasonable, actual costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (c)(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 (c)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

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

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee 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) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system will not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. However, for transportation systems purchased by the lessee or the lessee's affiliate that do not have a previously claimed MMS depreciation schedule, the lessee may treat the transportation system as a newly installed facility for depreciation purposes. With or without a change in ownership, a transportation system must be depreciated only once. Equipment may not be depreciated below a reasonable salvage value.

(B) MMS will allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance will be provided for depreciation. This alternative may apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be 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.

(vi) The deduction for transportation costs must be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported must be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product to the volume of all products in the gaseous phase. The lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(vii) Notwithstanding the requirements of paragraph (c)(2)(vi) of this section, the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(viii) Where both gaseous and liquid products are transported through the same transportation system, the lessee must propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee must submit all relevant data to support its proposal. MMS will then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(ix) Upon request by MMS, the lessee must submit all data used to determine its transportation allowance. The data must be provided within a reasonable period of time, as determined by MMS.

(d) *All pipelines—index-based valuation methods.* (1) This paragraph applies to determine transportation allowances each month for gas valued under the index-based valuation methods in § 206.454(b) of this subpart.

(2) Where the lessee's gas production from a well with a single connect is valued using an index-based method under § 206.454(b)(1), *and* a portion of the lessee's gas actually flows to the IPP used for value, the applicable transportation allowance must be determined under either paragraphs (b) or (c) of this section, as applicable. If the lessee's gas does not actually flow to the IPP, the transportation allowance for that pipeline must be determined under paragraph (d)(5) of this section.

(3) Where the lessee's gas production from a well with a split connect or multiple connection is valued using a weighted-average index value under § 206.454(b)(2)(i) of this subpart, the lessee first must determine the applicable transportation allowance under either paragraphs (b) or (c) of this section, as applicable, for gas volumes actually transported to each IPP used in the calculation to value the lessee's gas from the well. The volume weighted-average transportation allowance per MMBtu for all of the lessee's gas transported to each IPP used for valuation is the applicable transportation allowance for all of the lessee's gas from the well.

(4) Where the lessee's gas production from a well with a split connect or multiple connection is valued using the fixed-index value method under § 206.454(b)(2)(ii) of this subpart, and if some of the lessee's gas actually flows to the IPP selected for value, then the transportation allowance for all the lessee's gas from the well is determined based upon the lessee's transportation allowances per MMBtu, determined under paragraphs (b) or (c) of this section, as applicable, to transport gas to that IPP. If none of the lessee's gas actually flows to the IPP selected for value, the transportation allowance must be determined under paragraph (d)(5) of this section.

(5) A transportation allowance for a pipeline, or pipeline segment, through which a lessee's gas does not actually flow must be determined as follows:

(i) If it is a jurisdictional pipeline, the applicable transportation allowance rate is the maximum interruptible transportation (IT) rate for the pipeline for the month.

(ii) If it is a non-jurisdictional pipeline and the lessee is not affiliated with the owners of the pipeline, the applicable transportation allowance is determined based on either:

(A) A rate calculated by MMS at the lessee's request for a fee paid to MMS based on MMS' administrative costs of calculating that rate; or

(B) A rate determined by the lessee based on documentation supporting the non-jurisdictional pipeline's rate, including but not limited to any one of the following:

(*1*) an arm's-length contract;

(*2*) the pipeline's published rate; or

(*3*) the rate applicable to the lessee's actual transportation through the pipeline for any 30 days (not necessarily consecutive) in the previous 12 months.

(iii) If it is a non-jurisdictional pipeline and the lessee is affiliated with the owners of the pipeline, the applicable transportation allowance is determined under § 206.457(c).

(e) *Reporting.* Transportation allowances must be reported as a separate line item on Form MMS–2014, unless MMS approves a different reporting procedure.

(f) *Interest assessments.* (1) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest must be paid on the amount of that underpayment.

(2) Interest required to be paid by this section must be determined in accordance with 30 CFR 218.54.

(g) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014, the lessee will be required to pay additional royalties due plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS–2014, the lessee will be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in

accordance with instructions provided by MMS.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by MMS.

(h) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts, no cost will be allowed for transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or state regulatory agency-approved tariff.

(i) *Other transportation cost determinations.* The provisions of this section will apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

§ 206.458 Processing allowances—general.

(a) Where the value of any gas plant product is determined under § 206.453 of this subpart, a deduction will be allowed for the reasonable actual costs of processing. No processing allowance is applicable to any gas plant product valued under § 206.454.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product and processing plant relationship. Natural gas liquids (NGL's) must be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance may not be applied against the value of the residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product must not exceed 66⅔ percent of the value of each gas plant product determined in accordance with § 206.453 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 206.456 of this subpart).

(3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception must contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances may the value for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction will be allowed for the costs of placing lease products in marketable condition, including 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. Where gas is processed for the removal of acid gases, commonly referred to as 'sweetening,' no processing cost deduction will be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee will be eligible for a processing allowance as determined in accordance with this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which will be in addition to any other processing allowance to which the lessee is entitled under this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

(ii) Prior MMS approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to MMS in a form and manner prescribed by MMS.

(e) If MMS determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee must pay additional royalties, plus interest determined in accordance with 30 CFR 218.54, or will be entitled to a credit, without interest.

§ 206.459 Determination of processing allowances.

(a) *Arm's-length processing contracts.* (1)(i) For processing costs incurred by a lessee under an arm's-length contract, the processing allowance must be the reasonable actual costs incurred by the lessee for processing the gas under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee will have the burden of demonstrating that its contract is arm's-length.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee 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 in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length processing contract does not reflect the reasonable value of the processing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and lessor, then MMS will require that the processing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the processing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's processing costs.

(2) If an 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. No allowance may be taken for the costs of processing lease production which is not royalty-bearing.

(3) If an 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, the lessee must propose an allocation procedure to MMS. The lessee may use its proposed allocation procedure until MMS issues its determination. The lessee must submit all relevant data to support its proposal. MMS will then determine the processing allowance based upon the lessee's proposal and any additional information MMS deems necessary. No processing allowance will be granted for the costs of processing lease production which is not royalty bearing.

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

(5) MMS may require that a lessee submit arm's-length processing agreements and related documents. Documents must be submitted within a reasonable time, determined by MMS.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length processing contract or has no contract, including those situations where the lessee performs processing for itself, the processing allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations must be based upon the lessee's actual costs for processing during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

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

(ii) Allowable maintenance expenses include: Maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee 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) A lessee may use either depreciation or a return on depreciable capital investment. When a lessee has elected to use either method for a processing plant, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a processing plant will not alter the depreciation schedule established by the original processor/lessee for purposes of the allowance calculation. However, for processing plants purchased by the lessee or the lessee's affiliate that do not have a previously claimed MMS depreciation schedule, the lessee may treat the processing plant as a newly installed facility for depreciation purposes. With or without a change in ownership, a processing plant may be depreciated only once. Equipment may not be depreciated below a reasonable salvage value.

(B) MMS will allow as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied 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 must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be 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) The processing allowance for each gas plant product must be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product must be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing.

(4) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(3) of this section. MMS may grant the exception only if: (i) The lessee has arm's-length contracts for processing other gas production at the same processing plant; and (ii) at least 50 percent of the gas processed annually at the plant is processed under arm's-length processing contracts; if MMS grants the exception, the lessee must use as its processing allowance the volume weighted average prices charged other persons under arm's-length contracts for processing at the same plant.

(5) Upon request by MMS, the lessee must submit all data used by the lessee to determine its processing allowance. The data must be provided within a reasonable period of time, as determined by MMS.

(c) *Reporting.* Processing allowances must be reported as a separate line on the Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments.* (1) If a lessee erroneously reports a processing allowance which results in an underpayment of royalties, interest must be paid on the amount of that underpayment.

(2) Interest required to be paid by this section must be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual gas processing allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee will be required to pay additional royalties due plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a processing allowance. If the actual processing allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance period, the lessee will be entitled to a credit without interest.

(2) For lessees processing production from onshore Federal leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees processing gas production from leases on the OCS, if the lessee's estimated processing allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated costs were less than the actual costs, the refund procedure will be specified by MMS.

(f) *Other processing cost determinations.* The provisions of this section will apply to determine processing costs when establishing value using a net back valuation procedure or any other procedure that requires deduction of processing costs.

PART 211—LIABILITY FOR ROYALTY DUE ON FEDERAL AND INDIAN LEASES AND RESPONSIBILITY TO REPORT ROYALTY AND OTHER PAYMENTS

18. The authority citation for part 211 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.*; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, 1801 *et seq.*

Subpart C—Reporting and Paying Royalties

19. In section 211.18 as proposed to be added at 60 FR 30500 (June 19, 1995) a new paragraph (c) is added to read as follows:

§ 211.18 Who is required to report and pay royalties?

* * * * *

(c) *Persons who take production allocable to Federal or Indian leases in all other approved Federal or Indian agreements.* This paragraph provides requirements and instructions for reporting and paying royalties and other payments for Federal leases in approved Federal agreements comprised of leases with differing lessors, royalty rates, or fund distributions.

(1) Except as provided in paragraphs (c) (2) and (3) and (d) of this section, if you are an operating rights owner in a Federal lease in an agreement under this paragraph, you must report and pay royalties on your entitled share of production under the terms of the agreement. You must:

(i) File a PIF with MMS as specified in Part 210 of this title and the MMS Payor Handbooks;

(ii) Report the royalties owed for that production on a Form MMS–2014 and follow the instructions provided in Part 210 of this title and the MMS Payor Handbooks; and

(iii) Pay royalties on that production as specified in Part 218 of this title and the MMS Payor Handbooks.

(2) If you are an operating rights owner who meets the definition of a small operating rights owner in § 206.451 of this title, you may report and pay royalties each month on the volume of production you actually take subject to the following criteria:

(i) You must report your takes on Form MMS–2014 using a special code.

(ii) Within 6 months after the end of each calendar year in which you report based on takes, you must pay any additional royalties that may be due on the difference between your entitled share and the volume of production on which you reported and paid royalties in accordance with 30 CFR § 202.450(d)(1)(iv)(D).

(iii) If the volume of the production on which you reported and paid royalties for the calendar year is equal to or greater than the volume of your entitled share of production for that calendar year, you will not be assessed late payment interest for any sales month during the calendar year in which you underreported volume. However, MMS will assess interest for any reported volumes based on takes if the royalty value for those volumes was not properly reported and paid. MMS will allow a credit for any overtaken volumes in accordance with applicable procedures.

(iv) If the volume of the production on which you report and paid royalties for the calendar year is less than the volume of your entitled share of production for the calendar year, you must:

(A) Report and pay royalties on the difference between the volume of your entitled share of the production for the calendar year and the volume of the production on which you reported and paid under the takes basis; and

(B) Pay interest in accordance with MMS regulations and procedures on any underpaid royalties.

(3) You are not required to report and pay royalties on your entitled share of production under paragraph (c)(1) of this section if all operating rights owners in the agreement agree to assign reporting and payment responsibilities among themselves in an alternative manner that ensures that royalties are reported and paid properly each month on the full volume of production from or attributable to each Federal lease in the agreement.

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30 CFR Part 211

RIN 1010–AB45

Liability for Royalty Due on Federal and Indian Leases; Paying and Reporting Royalty and Other Payments

AGENCY: Minerals Management Service, Interior.

ACTION: Proposed rule; notice of meeting change and further extension of comment period.

SUMMARY: The Minerals Management Service (MMS) is rescheduling a public meeting in Houston, Texas, and extending the comment period for a proposed rulemaking regarding the liability for payments due on Federal and Indian leases and the responsibility to pay and report royalty and other payments (60 FR 54321, October 23, 1995).

The proposal was published in the Federal Register on June 9, 1995 (60 FR 30492). That notice proposes to establish and clarify which persons may be held liable for unpaid or underpaid royalties, compensatory royalties, or other payments on Federal and Indian mineral leases. The proposed rule also would establish who is required to report and pay royalties on production from leases not in approved Federal or Indian agreements or leases in approved Federal or Indian agreements containing 100 percent Federal or Indian tribal leases with the same lessor, the same royalty rate, and the same royalty distribution. MMS is further extending the comment period for this rule to January 26, 1996, from January 8, 1996 (60 FR 38533, July 27, 1995, and 60 FR 45112, August 30, 1995). Also, MMS is rescheduling the public meeting announced in the Federal Register (60 FR 54321, October 23, 1995) from November 29 and 30, 1995, to January 10 and 11, 1996. The meeting is to allow all interested parties an opportunity to discuss the proposed rulemaking. Interested parties are invited to attend and participate at this meeting. The meeting has been rescheduled as shown below.

DATES: A public meeting will be held on Wednesday January 10, and if necessary Thursday, January 11, 1996, from 9:00 a.m. until 5:00 p.m. Comments must be received on or before January 26, 1996.

ADDRESSES: The meeting will be held in Room 104, first floor, at the Houston Compliance Division Office, Minerals Management Service, 4141 North Sam Houston Parkway East, Houston, Texas, 77032. Comments should be sent to: David S. Guzy, Chief, Rules and Procedures Staff, Minerals Management Service, Royalty Management Program, P.O. Box 25165, MS 3101, Denver, Colorado 80225–0165, telephone (303) 231–3432, fax (303) 231–3194, e-Mail David__Guzy@smtp.mms.gov.

FOR FURTHER INFORMATION CONTACT: David S. Guzy, Chief, Rules and Procedures Staff, Minerals Management Service, Royalty Management Program, telephone (303) 231–3432, fax (303) 231–3194, e-Mail David__Guzy@smtp.mms.gov. Please contact Betty Casey at the Houston Compliance Division Office at telephone (713) 987–6802, fax (713) 987–6804