

DEPARTMENT OF THE INTERIOR**Office of Natural Resources Revenue****30 CFR Parts 1202 and 1206**

[Docket No. ONRR–2012–0004; DS63644000
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RIN 1012–AA13

**Consolidated Federal Oil & Gas and
Federal & Indian Coal Valuation
Reform**

AGENCY: Office of Natural Resources
Revenue (ONRR), Interior.

ACTION: Final rule.

SUMMARY: ONRR is amending our regulations governing valuation, for royalty purposes, of oil and gas produced from Federal onshore and offshore leases and coal produced from Federal and Indian leases. This rule also consolidates definitions for oil, gas, and coal product valuation into one subpart that is applicable to the Federal oil and gas and Federal and Indian coal subparts.

DATES: *Effective date:* January 1, 2017.

FOR FURTHER INFORMATION CONTACT: For questions on technical issues, contact Amy Lunt at (303) 231–3746, Lisa Dawson at (303) 231–3653, Karl Wunderlich at (303) 231–3663, Chris Carey at (303) 231–3460, Megan Hessee at (303) 231–3713, Richard Adamski at (202) 513–0598, or Carrie Wallace at (303) 445–0638.

SUPPLEMENTARY INFORMATION:

I. Background

The purpose of implementing this final rule regarding the valuation of oil and gas production from Federal leases and coal production from Federal and Indian leases is (1) to offer greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees and mineral revenue recipients; (2) to ensure that Indian mineral lessors receive the maximum revenues from coal resources on their land, consistent with the Secretary's trust responsibility and lease terms; (3) to decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) to provide early certainty to industry and to ONRR that companies have paid every dollar due.

Also, this final rule makes non-substantive technical or clarifying changes to the proposed rule. We re-wrote sections of the regulations in Plain Language to meet the criteria of Executive Orders 12866 and 12988 and the Presidential Memorandum of June 1,

1998, and to make our rules more clear, consistent, and readable.

II. Comments on Proposed Rule

On January 6, 2015, ONRR published a Proposed Rule to amend the valuation regulations for oil, gas, and coal produced from Federal leases and coal produced from Indian leases (80 FR 608). The proposed rule took into consideration input that we received on the Advance Notices of Proposed Rulemaking, which we published on May 27, 2011, regarding the valuation of oil, gas, and coal produced from Federal leases and coal produced from Indian leases (76 FR 30878, 30881). ONRR also considered input that we received during six public workshops that we held in September and October of 2011. The proposed rulemaking provided for a 60-day comment period, which closed on March 9, 2015. In response to over 50 stakeholder requests to extend the public comment period, we published a notice that granted a 60-day extension, which extended the comment period to May 8, 2015 (80 FR 7994). During the public comment period, we received more than 1,000 pages of written comments from over 300 commenters and over 190,000 petition signatories. We received comments from industry, industry trade groups, Congress, State governors, States, local municipalities, two Tribes, local businesses, public interest groups, and individual commenters. The petition signatories' main focus was on coal, and they aligned themselves with organizations that were either passionately against the further expansion of mining coal or were proponents of coal mining.

We carefully considered all of the public comments that we received during the rulemaking process and, in some instances, revised the language of the final rule based on these comments. We hereby adopt final regulations governing the valuation of oil, natural gas, and coal produced from Federal leases and coal produced from Indian leases. These regulations apply, prospectively, to oil, natural gas, and coal produced on or after the effective date that we have specified in the **DATES** section of this preamble.

General Comments

Because this final rule is composed of four subparts covering Federal oil and gas and Federal and Indian coal, we will organize, analyze, and respond to the comments regarding the specific subparts.

Public Comment: All of the over 190,000 petition signatories that ONRR received during the public comment period pertained to coal. The comments

and positions on coal production and values were polarized representing those supporting the coal industry and those supporting the platform highlighting green energy and coal's harm to the environment. The overwhelming majority of the signed petitions were from individuals asserting that coal production should cease and stay in the ground or that ONRR's proposed changes to coal valuation do not go far enough toward closing the perceived loopholes that the coal industry is exploiting. Many commenters who work in the coal industry or live in coal mining-dependent communities, along with one Tribe, maintain that the proposed rule goes too far. They argue that the rule imposes unwarranted valuation methods, including the "default provision," which, they contend, hinders transparency and creates complex and subjective coal valuations. They claim that the wholesale changes to the rule would cause irreparable economic harm to the coal industry by negatively disrupting the coal market.

ONRR Response: We appreciate the comments on both sides of the issue. The comments regarding keeping coal in the ground or regarding coal's negative impact on the socioeconomic health of communities by discouraging production, however, are beyond the scope of this rulemaking, which is limited to the valuation of coal produced from Federal and Indian leases for royalty collection purposes. We will, however, respond to the specific comments that suggested more stringent alternative valuation methods in the section-by-section analysis part of the preamble. As a general matter, many commenters have concerns about how the Federal Government leases coal, the amount of royalty charged, and whether taxpayers are getting a fair return from public resources. While this rule takes steps toward ensuring that the valuation process for Federal and Indian coal resources better reflects the changing energy industry while protecting taxpayers and Indian assets, its scope is not broad enough to address the many concerns the commenters raised. For that and other reasons, the U.S. Department of the Interior (Department) recently launched a comprehensive review to identify and evaluate potential reforms to the Federal coal program in order to ensure that it is properly structured to provide a fair return to taxpayers and reflect its impacts on the environment, while continuing to help meet our energy needs.

ONRR request for comments: In the proposed rule, we solicited comments on how to simplify and improve the

valuation of coal disposed of in non-arm's-length transactions and no-sale situations. We sought input on the merits of eliminating the benchmarks for valuation of non-arm's-length sales and comments on the following questions:

- Should the royalty value of coal initially sold under non-arm's-length conditions be based on the gross proceeds received from the first arm's-length sale of that coal in situations where there is a subsequent arm's-length sale?
- If you are a coal lessee, will adoption of this methodology substantively impact your current calculation and payment of royalties on coal, and how?
- What other methods might ONRR use to determine the royalty value of coal not sold at arm's-length that we may not have considered?

Public Comment: ONRR received only one response from an industry commenter addressing these questions. The commenter answered no to the first question and explained that valuing coal further away from the lease may not represent the true value of the coal at the lease. The commenter also added that the seller may not know who the first arm's-length purchaser may be. In response to the second question, the commenter believes that any subsequent transaction to an affiliate is not applicable to the marketability of the coal at the lease and that ONRR may or may not get a reasonable price for the valuation of the coal. The commenter responded to ONRR's third question seeking other methods by stating that ONRR should retain the benchmarks. The commenter further elaborated that the benchmarks should be reordered to 1, 4, 2, 3, and 5, plus adding a sixth benchmark (review of actual cost of production and assess a return on investment that is fair to the situation and/or the company under assessment), applicable only in those rare instances when no arm's-length sales are available.

ONRR also received several comments suggesting the option to base the value of coal on an index price.

ONRR Response: The best indication of value is the gross proceeds received under an arm's-length contract between independent persons who are not affiliates and who have opposing economic interests regarding that contract. The best indicator of value under a non-arm's-length sale is the gross proceeds accruing to the lessee or its affiliate under the first arm's-length contract, less applicable allowances. In this final rule, we eliminated the benchmarks for both natural gas and

coal. We implemented this method for Federal oil in 2000 and, in this final regulation, made it consistent for Federal gas and Federal and Indian coal.

ONRR is not currently aware of any published index prices for coal that cover a wide array of coal production that are both transparent and widely traded so as to yield a reasonable value that would represent the true market value of coal. We will monitor the coal market and may be open to considering index prices as a valuation option, if viable.

Public Comment: ONRR received a few general comments concerning Federal oil and natural gas production. These comments fell into several categories, including natural gas measurement methods, ONRR's unbundling program, and the economic impact on the oil and gas industry.

ONRR also received general comments concerning Federal and Indian coal production. These comments fell into several categories, including the final rule's impact on coal production and the coal industry, royalty rates, and creating more transparency to the public for coal valuation.

ONRR Response: Some of these comments were beyond the scope of the rule so ONRR did not address them specifically. We addressed other comments in the specific comment sections.

Regarding the comments on coal royalty rates, the royalty rate is a lease clause and is not a component of this final rule. Royalty rates are a part of lease negotiations, which the Bureau of Land Management (BLM), Bureau of Ocean Energy Management (BOEM), and Bureau of Indian Affairs (BIA) on behalf of the Tribes and individual Indian mineral owners conduct. The final rule does not limit or otherwise infringe on the authority of these entities to negotiate those leases. Instead, this rule is focused on ensuring that Federal and Indian mineral owners receive the royalties that are owed to them based on the value of the resources being sold and consistent with the royalty terms of the applicable leases negotiated by the BLM, BOEM and BIA.

As to comments related to increasing transparency, the U.S. Department of the Interior (Department) created a data portal as part of the Extractive Industries Transparency Initiative—a global, voluntary partnership to strengthen the accountability of natural resource revenue reporting and build public trust for the governance of these vital activities. You can access the data portal at <https://useiti.doi.gov>.

A. Specific Comments on 30 CFR Part 1206—Product Valuation, Subpart A—General Provisions and Definitions

1. Definitions (§ 1206.20)

In this final rule, ONRR consolidated the definitions from Federal oil (§ 1206.101), Federal gas (§ 1206.151), Federal coal (§ 1206.251), and Indian coal (§ 1206.451). ONRR consolidated the existing definitions for these products to provide greater clarity and to eliminate redundancy. ONRR received comments on some of the modified definitions, which we discuss below.

Area: See discussion in this preamble under § 1206.105 regarding the definition of the term “area.”

Coal Cooperatives: ONRR added a new definition of the term “coal cooperatives” that defines formal or informal organizations of companies or other entities sharing in a common interest to produce and market coal or coal-based products, the latter generally being electricity.

Public Comment: One commenter argued that defining a coal cooperative was unnecessary. The commenter suggested that contracts are either arm's-length or non-arm's-length and that it does not matter if affiliated parties are part of a corporation or an ONRR-defined cooperative.

ONRR Response: We seek a clear, consistent, and repeatable standard for valuing coal at its true market value. Coal cooperatives are formal or informal organizations of companies or other entities sharing in a common interest to produce and market coal or coal-based products, the latter generally being electricity. The services and benefits that coal cooperatives provide include, but are not limited to, manufacturing, selling, sampling, storing, supplying, permitting, transporting, marketing, or other logistic services. The relationship between a coal cooperative's members is not one of “opposing economic interests” and, therefore, is not at arm's-length.

If none of the members own 10 percent or more of the coal cooperative, the coal cooperative will not be an affiliate under the definitions in this rule found in § 1206.20. Nevertheless, the relationship between the coal cooperative and its members, as well as between the coal cooperative's members, is not at arm's-length for valuation purposes because they lack opposing economic interests. Therefore, the lessee must base the value of its coal production on the first arm's-length sale price received for the coal or electricity. We retained the term “coal cooperative,” but, in light of the

comment that we received, we changed the proposed definition.

Gathering: In this final rule, any movement of bulk production from the wellhead to a platform offshore is gathering and not transportation. ONRR changed the definition of the term “gathering” and added paragraph (a)(1)(ii) in §§ 1206.110 and 1206.152 to rescind the May 20, 1999, “Guidance for Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters” (Deep Water Policy). The Deep Water Policy allowed lessees to deduct certain costs associated with moving bulk production from the seafloor to the first platform.

Public Comment: ONRR received several comments from industry and industry trade groups opposing our proposal to rescind the Deep Water Policy. Generally, the commenters opposed the categorical exclusion of subsea movement costs prior to the first platform as a transportation allowance. The commenters argued that such a determination was arbitrary and capricious. The commenters stated that rescinding the Deep Water Policy penalizes the development of innovative technologies that minimize surface facilities, reduce environmental risks, and increase ultimate recovery. Commenters stated that ONRR previously identified the movement of bulk production to the first platform as a valid transportation deduction and argue that we are now failing to provide sufficient justification to warrant rescinding the Deep Water Policy.

ONRR received comments from public interest groups and a State supporting the removal of the Deep Water Policy. These commenters argued that the Deep Water Policy was inconsistent with ONRR’s definition of gathering, and rescinding the policy will cure improper deductions of subsea gathering costs. In addition, the commenters believe that the proposed change will assure a fair market value for production while also reducing administrative costs for the oil and gas industry.

ONRR Response: The former Minerals Management Service intended for the Deep Water Policy to incentivize deep water leasing by allowing lessees to deduct broader transportation costs than the regulations allowed. ONRR concluded that the Deep Water Policy has served its purpose and is no longer necessary. The regulations still allow offshore lessees to deduct considerable transportation costs to move oil and gas from the offshore platform to onshore markets. Rescinding this policy clarifies the meaning of gathering, which, in

turn, provides a more consistent and reliable application of the regulations.

Public Comment: ONRR received comments stating it understated the cost estimate of the impact to industry from removing the Deep Water Policy. The commenters claim the cost of removing the Deep Water Policy is much higher than ONRR’s estimated \$17.4 to \$23.6 million total annual loss to all of industry.

ONRR Response: ONRR does not agree. ONRR estimated the costs to industry using actual costs industry provided to ONRR during audits of the subsea gathering pipelines. ONRR used this data to estimate a per mile cost for subsea gathering pipelines. ONRR then used this per mile cost to calculate the total burden on industry associated with eliminating the Deep Water Policy. ONRR stands by its analysis.

Misconduct: ONRR added a new definition for the term “misconduct.” This new definition will apply to—and in conjunction with the—default provision. Misconduct, in this subpart, is different than—and in addition to—any violations subject to civil penalties under the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. 1719, and its implementing regulations in 30 CFR part 1241. Behavior that constitutes misconduct under part 1206 does not need to be willful, knowing, voluntary, or intentional. This is a valuation mechanism, not an enforcement tool.

Public Comment: Industry claims that the definition of misconduct is overly broad and argues that any common understanding of misconduct implies an element of intentional wrongdoing. Industry fears that ONRR may expand the use of the term to include even minor occurrences, such as simple reporting errors.

ONRR Response: According to *Black’s Law Dictionary*, the term “misconduct” is “any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior, regardless of the mental state of the lessee or any individual employed by, or associated with, the lessee.” Consistent with this definition, this final rule does not require behavior to be willful, knowing, voluntary, or intentional to constitute misconduct. We only intend to use this definition of the term “misconduct” for valuation purposes, not for imposing penalties. Thus, no intent is required. Moreover, FOGRMA does not mandate a particular mental state for a lessee’s obligation to correctly report, account for, and pay royalties for purposes of royalty valuation. For example, under this final rule, if we determine that you

improperly calculated the value of your gas due to misconduct, we will calculate the value of your gas under § 1206.144. However, if we determine that the misconduct was knowing or willful, we may pursue civil penalties under 30 CFR part 1241.

B. Specific Comments on 30 CFR Part 1206—Product Valuation, Subpart C—Federal Oil

1. Calculating Royalty Value for Oil Sold Under an Arm’s-Length Contract (§ 1206.101)

Default: ONRR added that the value in this paragraph does not apply if we decide to value your oil under its new default valuation provision, which allows us to value your oil production under § 1206.105 or any other provision in this subpart. We also added that we may decide a lessee’s oil value under the default valuation provision if the lessee fails to make the election in this paragraph related to exchange agreements.

Public Comment: Almost unanimously, industry commenters object to the use of ONRR’s default provision for oil. Industry comments highlight the following concerns: “standardless” ONRR discretion, second-guessing of arm’s-length contracts and other lessee valuations, and a denial of lessees’ ability to deduct all appropriate costs to reflect value at the lease. Several industry commenters argued against ONRR’s ability to determine royalty value when a lessee or designee sells oil or gas for ten percent less than the lowest reasonable measures of market value. The industry commenters claim that different companies can negotiate better prices than others based on size and bargaining power.

Several industry trade groups stated that it is not clear which offices (audit and compliance, enforcement, valuation, etc.) within ONRR have the ability to invoke the default provision and question whether there would be consistency in its application. These industry commenters also believe that the default provision (1) does not allow ONRR to honor arm’s-length contracts and gross proceeds as the basis of valuation as in the past; (2) lacks specific criteria for determining what is reasonable valuation; (3) ONRR should not use it for simple reporting errors; and (4) is burdensome, an overreach of valuation authority, and creates uncertainty. Several industry trade groups add that the proposed rule offers little more than “*raw ipse dixit*” for promulgating its default provision and how ONRR intends to use it.

Several public interest groups suggested that the default provision should be mandatory and not discretionary. The consolidated comments from the State and Tribal Royalty Audit Committee (STRAC) provide that the State or Tribe must grant approval if ONRR applies the default provision in their jurisdiction.

ONRR Response: ONRR disagrees with the commenters' statements that the default provision is a radical departure from our previous valuation policy. The regulatory changes do not alter the underlying principles of the previous regulations. For example, nothing in this final rule changes the Department's requirement that, for purposes of determining royalty, the value of crude oil produced from Federal leases is determined at or near the lease. And nothing in this final rule changes the fact that gross proceeds from arm's-length contracts are the best indication of market value.

The default provision addresses valuation situations where circumstances result in the Secretary of the Interior's (Secretary) inability to reasonably determine the correct value of production. Such circumstances include, but are not limited to, the lessee's failure to provide documents, the lessee's misconduct, the lessee's breach of the duty to market, or any other situation that significantly compromises the Secretary's ability to reasonably determine the correct value. The mineral statutes and lease terms give the Secretary the authority and considerable discretion to establish the reasonable value of production by using a variety of discretionary factors and any other information that the Secretary determines is relevant. The default provision simply codifies the Secretary's authority to determine the value of production for royalty purposes and specifically enumerates when, where, and how the Secretary will use that discretion.

Under this final rule, ONRR will continue the same treatment of arm's-length contracts as we have historically. We have never tacitly accepted values received under arm's-length contracts. We analyze all types of sales contracts in our reviews in order to validate proper value and deductions.

Some commenters contend that ONRR did not perform an adequate economic analysis in assigning a royalty impact to invoking the default provision. We disagree and emphasize, again, that we anticipate using the default provision only in very specific cases where we cannot determine proper royalty values through standard procedures. Moreover, the royalty impact will be relatively

small because the default provision will always establish a reasonable value of production using market-based transaction data, which has always been the basis for our royalty valuation rules.

ONRR considers a lessee's refusal to provide requested documents to be a failure to permit an audit that is, and will continue to be, subject to civil penalties. ONRR's choice to invoke the default provision will not impact the lessee's obligation to provide documents or ONRR's ability to assess civil penalties for failure to permit an audit.

Some commenters stated that it is not clear which offices within ONRR will apply the default provision and, if they did, what valuation criteria they would employ. We anticipate that, in most cases, we will use the default provision during the course of an audit. And, as we stated, the criteria that we would use to establish a royalty value is the same basic criteria upon which we base all royalty values. We list these criteria in § 1206.105(a)–(f). Specifically, we may consider the value of like-quality oil in the same field or nearby fields or areas; the value of like-quality oil from the same plant or area; public sources of price or market information that we deem to be reliable; information available and reported to us, including, but not limited to, on the Report of Sales and Royalty Remittance (Form ONRR–2014) and the Oil and Gas Operations Report (Form ONRR–4054); costs of transportation, if we determine that they are applicable; or any information that we deem relevant regarding the particular lease operation or the salability of the oil.

Some industry commenters expressed concerns over their ability to challenge our use of the default provision. Industry's concerns are unwarranted because a company may appeal an order, including an order wherein we used the default provision to determine royalty value. Appeal rights under 30 CFR part 1290 will not change under this final rule.

We disagree with those commenters who sought to make the default provision mandatory. We reiterate that we intend to use the default provision only in specific cases where conventional valuation procedures have not worked to establish a value for royalty purposes. We have the authority to use the default provision on behalf of the Secretary and as part of our delegated or cooperative agreements. We will work with STRAC to determine the royalty value of production that occurs in an affected State or on Tribal lands.

2. Calculating Royalty Value for Oil Not Sold Under an Arm's-Length Contract (§ 1206.102)

Default: ONRR added a default valuation provision that allows us to value your oil production under § 1206.105 or any other provision in this subpart. We addressed comments pertaining to the "Default Provision" paragraph, which we detail in § 1206.101, in this Preamble.

3. Determination of Correct Royalty Payments (§ 1206.104)

Default: ONRR added a default valuation provision that allows us to value your oil production under § 1206.105 or any other provision in this subpart. We addressed comments pertaining to the "Default Provision" paragraph, which we detail in § 1206.101, in this Preamble.

Misconduct: ONRR added a new definition for the term "misconduct." We addressed comments pertaining to this definition, which we detail in § 1206.20, in this Preamble.

Unreasonably high transportation cost: ONRR added a default provision allowing us to determine your transportation allowance under § 1206.105 if (1) there is misconduct by or between the contracting parties; (2) the total consideration that you or your affiliate pays under an arm's-length contract does not reflect the reasonable cost of transportation because you breached a duty to market oil for the mutual benefit of the lessee and the lessor by transporting oil at a cost that is unreasonably high; or (3) ONRR cannot determine if you properly calculated a transportation allowance for any reason. We addressed the default provision in detail in § 1206.101.

Public Comment: Many of the comments from industry and industry trade groups regarding our potential use of the default provision as it relates to the transportation of oil mirror those put forth for determining the value of oil. Commenters believe that our use of a 10-percent variance above the highest reasonable measure of transportation standard is arbitrary, capricious, and unnecessary. Some comments representing States' interests, however, believe that ONRR should include stronger regulatory language requiring us to use the default method when the 10-percent variance is reached.

ONRR Response: The default provision is an accommodating and necessary valuation tool that allows the Secretary to determine the correct amount of transportation deductions for oil. The 10-percent variance that we may use in our analysis of

transportation transactions is nothing more than a tolerance to help determine a proper transportation allowance. In past and current compliance reviews and audit procedures, we have always used tolerances to reflect what is reasonable in any given market at any given time. Our use of the default provision under the final valuation regulations is a continuation of current practice. We will continue to determine transportation costs that industry incurs on their own merits based on reasonable actual costs allowable under the regulations.

Written contracts: In this final rule, a lessee or its affiliate must have all of its contracts, contract revisions, or amendments in writing and signed by all the parties to those contracts, revisions, or amendments. Where the lessee does not have a written contract, ONRR may use the default provision to determine value.

Public Comment: We received multiple comments on the rule's new provision stating that we will determine transportation allowances under § 1206.105 if lessees do not have a written contract. The commenters generally disagreed with our requirement that all contracts be in writing because such a requirement is inconsistent with industry contracting procedures. Commenters also noted that contracts that are not in writing are still enforceable and that ONRR's definition of a contract in § 1206.20 includes oral contracts that are legally enforceable.

ONRR Response: FOGRMA requires the Secretary to "establish a comprehensive inspection, collection and fiscal and production accounting and auditing system to provide the capability to accurately determine oil and gas royalties . . . and to collect and account for such amounts in a timely manner." 30 U.S.C. 1711(a). FOGRMA also requires lessees to provide "any information the Secretary, by rule, may reasonably require" 30 U.S.C. 1703(a). Since adopting the regulations in 1988, ONRR has required lessees to value their oil and gas production based on the gross proceeds accruing to the lessees for the sale of that oil and gas. These gross proceeds include deductions for the lessees' reasonable and actual costs of transportation. When lessees calculate their gross proceeds that include arm's-length sales and arm's-length transportation costs, the lessees must use the terms of those arm's-length contracts to calculate their gross proceeds. We have the responsibility of auditing gross proceeds in order to ensure that they reflect the total consideration actually transferred, either directly or indirectly, from the

buyer to the seller. Through this auditing process, we have found it difficult to verify the accuracy of lessees' royalty payments when the lessees enter into oral contracts.

This final rule's requirement that all arm's-length contracts be in writing is a logical evolution of our previous regulations. Section 1207.5 requires lessees to commit oral contracts to written form and keep them as records. And the previous rules required arm's-length sales contract revisions and amendments to be in writing and signed by all parties. For more information about this, see §§ 1206.153(j), 1206.52(d)(2), 1206.102(e)(2)(ii) (requiring any amendment or revision to arm's-length purchase prices for oil to be in writing and signed by all parties in the agreement). By requiring fully-executed arm's-length contracts, we no longer rely just on the lessee's written documentation outlining the terms of oral contracts. This guarantees that we can verify that the lessee's gross proceeds calculations are correct and include all consideration that you documented in the contract.

One commenter provided case law indicating that contracts do not have to be in writing to be enforceable. This comment, however, ignores the burden that we bear to verify and accurately determine that the lessees' royalty payments are correct. We must audit and evaluate countless contracts in order to verify royalty payments for Federal and Indian lands. Tracking email exchanges, letters, or other confirmations creates inefficiencies in our accounting and auditing systems, which limits our ability to fulfill FOGRMA's mandate to verify and account for royalty payments.

4. Determination of the Oil Value for Royalty Purposes (§ 1206.105)

Default: ONRR added a default valuation provision that allows us to value your oil production under § 1206.105 or any other provision in this subpart. We addressed comments pertaining to the "Default Provision" paragraph, which we detail in § 1206.101, in this Preamble.

Area: ONRR removes the phrase "legal characteristics" from the definition of the term "area."

Public Comment: We received comments from industry that they oppose the modified definition of "area." The commenters believe that the new definition would "revise the definition of area in a manner that overtly changes the breadth of the marketable condition rule." The commenters rely on the Interior Board of Land Appeals' (IBLA) decision in

Encana Oil & Gas (USA), Inc., 185 IBLA 133 (2014) (*Encana*) as an example to illustrate how the definition of area has expanded over time. One commenter stated, "In short, the ONRR's proposed revision of the definition of 'area' will result in inconsistent and uncertain marketable condition determinations."

ONRR Response: We modified the definition of the term "area" to clarify that an area does not have boundaries or names. The commenter's concern, however, is misplaced because the definition of the term "marketable condition" remains the same. And, as the commenter points out, case law aids in defining the term "marketable condition." We cite *Encana* as the basis for this, where the finding was that a "sales contract typical for the field or area" reasonably refers to the contracts that are typical in the field or area into which the gas is actually sold, which may or may not be the field or area where the gas is produced. Because we do not change the definition of the term "marketable condition" and our modification to the term "area" does not alter the precedent set out in *Encana* and other cases interpreting the definition of the term "marketable condition," we are retaining the definition of the term "area" as we have proposed.

5. Valuation Determination Requests (§ 1206.108)

Guidance and Determinations: Under paragraph (a), a lessee may request a valuation determination or guidance from ONRR regarding any oil produced. Paragraph (a) provides that the lessee's request for a determination must (1) be in writing; (2) identify all leases involved; (3) identify all interest owners in the leases; (4) identify the operator(s) for those leases; and (5) explain all relevant facts. In addition, under paragraph (a), a lessee must provide (1) all relevant documents; (2) its analysis of the issue(s); (3) citations to all relevant precedents (including adverse precedents); and (4) its proposed valuation method.

In response to a lessee's request for a determination, ONRR may (1) decide that we will issue guidance; (2) inform the lessee in writing that we will not provide a determination or guidance; or (3) request that the Assistant Secretary for Policy, Management and Budget (ASPMB) issue a determination.

Paragraphs (b)(3)(i) and (ii) identify situations in which ONRR and the Assistant Secretary typically do not provide a determination or guidance, including, but not limited to, requests for determinations or guidance on hypothetical situations and matters that

are the subject of pending litigation or administrative appeals.

Under paragraph (c)(1), a determination that the ASPMB signs binds both the lessee and ONRR unless the Assistant Secretary modifies or rescinds the determination.

Public Comment: Industry raised three concerns regarding valuation guidance and determinations. First, commenters were concerned that ONRR will require excessive data and legal analysis in order for industry to receive valuation guidance or a determination. Second, commenters suggest that ONRR add language specifying that, if a lessee receives non-binding guidance and then chooses not to follow that guidance, ONRR would not pursue civil penalties based on that guidance. Third, commenters suggest that ONRR provide only appealable determinations and binding determinations that the ASPMB signs rather than non-appealable, non-binding guidance.

ONRR Response: In this final rule, we retained the language requiring industry to provide specified information to receive a valuation determination. However, we recognize that, where a lessee requests valuation guidance rather than a determination, less information may suffice because requests for guidance are not requests for our approval of a valuation method.

Under 30 CFR part 1241, ONRR may issue a notice of non-compliance if you fail to comply with any requirement of a statute, regulation, order, or terms of a lease. Because this language clearly establishes when we may issue a notice of non-compliance, it is not necessary to add language specifically addressing civil penalties for failure to follow non-binding guidance.

We provide guidance in cases where industry has a question regarding the application of statutes and regulations to a particular set of circumstances. This guidance provides industry with an opportunity to ask questions about their particular circumstances without proposing a valuation method. Requests for determinations, on the other hand, are proposals from industry for ONRR approval of a specific valuation method. By providing a guidance option, we can answer questions more quickly and without requiring industry to submit all of the information that we would require for a determination. Industry may always request a binding determination.

6. General Transportation Allowance Requirements (§ 1206.110)

In this final rule, we re-ordered paragraph (a) to add clarity.

Subsea gathering: In paragraph (a), we added a new provision stating that you may not take a transportation allowance for the movement of oil produced on the Outer Continental Shelf (OCS) from the wellhead to the first platform. This addition, along with the changes to the definition of gathering, rescinds the Deep Water Policy. We addressed comments pertaining to this issue in § 1206.20.

Fifty-percent allowance cap: In this final rule, we eliminated the regulation allowing us to approve transportation allowances in excess of 50 percent of the value of a lessee's oil production. Under this final rule, any prior approvals terminate on the date when this rule becomes final.

Public Comment: We received comments from States and public interest groups supporting the elimination of ONRR's authority to approve transportation allowances in excess of the 50-percent allowance cap. However, the State commenters asserted that the 50-percent cap, itself, was too broad. The States suggested that we calculate allowance caps for each State and use a percentage based on the average transportation costs in each State over a ten-year period. The State commenters suggested that we update and post such percentages on our Web page.

ONRR Response: At this time, we decline to implement the States' suggestion to reevaluate caps on transportation allowances as a whole. The 50-percent limitation is not the only check on the reasonableness of transportation costs. The 50-percent limitation supplements the requirement that a lessee's transportation costs be actual and reasonable. In this final rule, the limitation clause states that your transportation allowance may not exceed 50 percent of the oil value determined under § 1206.101. This final rule defines the term "*transportation allowance*" as a deduction in determining royalty value for reasonable, actual costs that the lessee incurs for moving oil to a point of sale or delivery off of the lease. The 50-percent limitation is a limit on the allowance—a lessee's reasonable, actual costs of transportation—and not a statement that any cost up to 50 percent is reasonable. To find otherwise would allow a lessee to spend \$100 on a repair that could have been performed for \$10 and deduct the entirety of the expense against a \$200 royalty obligation. Thus, the regulation, read as a whole, mitigates the States' concern.

Public Comment: ONRR received several comments from industry and industry trade groups opposing the

elimination of our authority to approve transportation allowances in excess of the 50-percent allowance cap. These commenters stated that the right to request approval to exceed the 50-percent limitation is necessary because its removal denies a lessee the ability to deduct all of its actual, reasonable, and necessary transportation costs when those costs exceed 50 percent.

ONRR Response: The 50-percent limitation is a sufficient transportation allowance. The Mineral Leasing Act (MLA) requires lessees to pay royalties at 12½ percent in amount or value of production removed or sold from the leased lands. The Outer Continental Shelf Lands Act (OSCLA) requires a royalty of not less than 12½ percent in amount or value of production saved, removed, or sold from the leases. However, the MLA and OSCLA do not define the term "*value*," which gives the Secretary considerable discretion to define the term "*value*." The regulations at 30 CFR part 1206 determine value and, under these regulations, the Secretary allowed deductions for transportation allowances. It is this discretion that provides an allowance, generally, which the Secretary now caps at 50 percent of the value of oil production.

Public Comment: Several commenters take issue with ONRR terminating any approval that it previously issued for a lessee to exceed the 50-percent limitation. The commenters believe that terminating prior approvals is "retroactive." Thus, the commenters suggest that ONRR should allow such approval to expire on the expiration date set out in the approval.

ONRR Response: We disagree with the commenters who claim that the proposed rule's termination of prior approvals to allow transportation allowances to exceed the value of a lessee's oil production is retroactive. In *Reynolds v. United States*, 292 U.S. 443, 449 (1934), the Supreme Court determined that "a statute is not rendered retroactive merely because the facts or requisites upon which it's subsequent action depends, or some of them, are drawn from a time antecedent to the enactment." This means, as long as the new rule does not modify "the past legal consequences of past actions," those rules are not improperly retroactive. *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 219–20 (1988) (J. Scalia, concurring). Just because an agency's rule may "upset[] expectations based on prior law" does not mean the rule is retroactive. *Mobile Relay Associates v. F.C.C.*, 457 F.3d 1, 10–11 (D.C. Cir. 2006).

While terminating prior approvals to exceed the 50-percent cap for transportation allowances may disappoint some lessee's expectations, the rule, itself, is not retroactive because it does not affect the legal consequences of the lessee's past actions. Prior to this final rule, under our approval, a lessee was able to deduct transportation allowances that were higher than 50 percent of the value of the lessee's oil production. The new rule does not hinder the lessee's ability to do so for past production months; however, for each production month after the effective date of this rule, a lessee will no longer be able to deduct over 50 percent of the value of its oil production as a transportation allowance. Thus, this final rule is entirely prospective and not, as the opposing comments suggest, retroactive.

ONRR approved most requests to exceed the 50-percent cap on transportation allowances for a one-year period. Rarely, we approved them for a two-year period. In either case, the proposed rule put lessees on notice that we intended to remove such approvals.

Public Comment: A few commenters also state that, because ONRR retained a similar provision in the new Indian oil valuation amendments, removing that provision here would be arbitrary.

ONRR Response: While we retained the provision in the Indian oil valuation amendments, we have never received a request to exceed the 50-percent limitation on transportation allowances for Indian oil. And, unlike with this rule, the purpose of the Indian oil valuation amendments was to implement recommendations from a negotiated rulemaking committee. Because the committee did not recommend a change, we retained this provision. We may revisit the issue of a cap on transportation allowances claimed on Indian oil at a later date.

Eliminating transportation factors: Previously, ONRR allowed lessees to net transportation from their gross proceeds when the lessees' arm's-length contract reduced the price of the oil by a transportation factor. In this final rule, we eliminated this provision and, instead, require lessees to report such costs as a separate entry on Form ONRR-2014.

Public Comment: ONRR received comments from industry, industry trade groups, and an individual commenter opposing the elimination of transportation factors. The commenters stated that, if ONRR eliminated transportation factors, it would result in numerous complications due to insufficient guidance.

One industry trade group pointed out that ONRR does not define the term "*transportation factor*" in the proposed rule, and it is, therefore, unclear what is or is not a transportation factor. They suggest that, if ONRR pursues not allowing the netting of the transportation factor, ONRR needs to clearly define the term.

The commenters also noted that lessees will have a difficult time discerning what a transportation factor is because the lessees do not incur the costs, their purchasers do. Therefore, the commenters claim that the detail of the costs is not readily available to lessees to accommodate reporting the costs separately as transportation allowances. One commenter stated that transportation factors may include multiple items, "some of which may not be considered a transportation factor."

ONRR Response: In this final rule, lessees may deduct their reasonable actual costs of transportation. The burden lies with the lessees to support their reasonable actual costs of transportation. We have never defined the term "*transportation factor*." Historically, we used the term "*transportation factor*" to identify the situation when a sales contract contains a provision to reduce the base price by costs that the purchaser incurred to move the production to a downstream location.

These comments underscore why we eliminated transportation factors: To facilitate transparency, audits, and reviews. Eliminating factors ensures that transportation allowances are measurable and auditable because we can identify and audit transportation deductions when lessees report them separately from their sales price. When lessees report their sales value net of transportation, we cannot discern the transportation costs from the sales value. Moreover, the comment stating that transportation factors include multiple other items, including quality differences and services that may not be deductible from the royalty basis, shows the difficulty that we face in reviewing transportation factors as allowable transportation deductions. The factors may include bundled costs or may be a differential. Yet lessees, not ONRR, have the burden of identifying their allowable, reasonable, and actual costs of transportation. Eliminating transportation factors and requiring lessees to report transportation separately as allowances ensures that lessees meet that burden.

Misconduct: ONRR added a new definition for the term "*misconduct*." We addressed comments pertaining to

this issue, which we detail in § 1206.20, in this Preamble.

Default: ONRR addressed comments pertaining to the "Default Provision" paragraph, which we detail in § 1206.101, in this Preamble.

Unreasonably high transportation cost: ONRR addressed comments pertaining to this issue, which we detail in § 1206.104, in this Preamble.

7. Determination of Transportation Allowances for Arm's-Length Transportation (§ 1206.111)

Line fill: ONRR retains the provision allowing a lessee to include the costs of carrying line fill on its books as a component of arm's-length transportation allowances. We deleted proposed § 1206.111(c)(9) and retained line fill as an allowable deduction in the final rule as the new § 1206.111(b)(11). Because oil will only flow through a pipeline if that pipeline is filled with oil, some pipeline operators require that shippers (lessees) leave some of their oil in the pipeline. The shipper's oil that remains in the pipeline is, in effect, inventory that cannot be sold as long as the shipper uses the pipeline to transport its oil. In other cases, the pipeline operator owns the oil that fills the line and charges the shipper a cost at least equal to its capitalized costs as part of the arm's-length price or tariff. We proposed to eliminate this provision because we considered this to be a cost of marketing the oil, reasoning that line fill occurs after the royalty measurement point and is necessary in order for the pipeline operator to transport Federal oil production to downstream markets. We requested comments on whether line fill is a marketing cost.

Public Comment: ONRR received several comments on line fill. Industry pointed out that, in the 2004 Federal Oil Valuation Rule, ONRR identified line fill as a cost of transportation. In that same rulemaking, ONRR also pointed out that they do not allow a lessee to deduct the costs of marketing. At that time, ONRR recognized that line fill is not a marketing cost. Industry believes that line fill is not a cost of marketing oil. Instead, industry believes that, in cases where the pipeline requires it to dedicate its oil to transport its oil, ONRR should permit the cost of carrying this inventory as an allowable transportation deduction.

A public interest group supported the change and believes that the removal of this provision is in keeping with the overall goal of achieving a fair return for the taxpayer. One State agreed with ONRR's proposal, noting that line fill falls within a lessee's duty to market.

ONRR Response: We agree with industry commenters that lessees may deduct their reasonable actual transportation costs. For those lessees who must provide production as line fill, we retained the provision that allows the cost of carrying on your books as inventory a volume of oil that you or your affiliate, as the pipeline operator, maintain(s) in the line as line fill as an allowable transportation cost.

Written contracts: We added a new provision that states that we will determine transportation allowances under § 1206.105 if lessees do not have a written contract for the arm's-length transportation of oil. We addressed comments pertaining to this issue, which we detail in § 1206.104, in this Preamble.

Eliminating transportation factors: Previously, ONRR allowed lessees to net transportation from their gross proceeds when the lessees' arm's-length contract reduced the price of the oil by a transportation factor. In this final rule, we eliminated this provision and, instead, require lessees to report such costs as a separate entry on Form ONRR-2014. We addressed comments pertaining to this issue, which we detail in § 1206.110, in this Preamble.

8. Determination of Transportation Allowances for Non-Arm's-Length Transportation Contracts (§ 1206.112)

Line fill: ONRR retains the provision that allows lessees to include the costs of carrying line fill on their books as a component of arm's-length transportation allowances. We deleted proposed § 1206.111(c)(9) and retained line fill as an allowable deduction in the final rule as the new § 1206.112(c)(1)(v). We proposed to eliminate this provision because we considered this a cost of marketing the oil, reasoning that line fill occurs after the royalty measurement point and is necessary in order for the pipeline operator to transport Federal oil production to downstream markets. We requested comments on whether line fill is a marketing cost. We addressed comments pertaining to this issue, which we detail in § 1206.110, in this Preamble.

Pipeline losses: In this final rule, under paragraph (c)(2)(ii), ONRR eliminated the provision that allows lessees to deduct the costs of pipeline losses, both actual and theoretical, under non-arm's-length transportation situations.

Public Comment: Multiple companies and industry trade groups opposed removing the provision that allows lessees with non-arm's-length transportation arrangements to deduct actual and

theoretical losses, stating that losses are a real cost to lessees.

A State commenter supported this change and suggested disallowing all losses, including line loss charges under arm's-length contracts. A public interest group supported this change, stating that this change will ensure that royalty value is based on oil actually removed from the lease without subsidizing losses occurring after the royalty measurement point.

ONRR Response: Beginning with the May 5, 2004, Federal Oil Valuation Rule, we allowed lessees to deduct the costs of actual line losses in non-arm's-length oil transportation situations. Since that time, it has been difficult for lessees to demonstrate, and impractical for us to verify, that line losses in non-arm's-length or no-contract situations are valid and not the result of meter error or other difficult-to-measure causes.

FOGRMA requires the Secretary to "establish a comprehensive inspection, collection and fiscal and production accounting and auditing system to provide the capability to accurately determine oil and gas royalties . . . and to collect and account for such amounts in a timely manner" (30 U.S.C. 1701(a)). Because we must account for all royalties and associated deductions and because we cannot properly verify deductions associated with losses in non-arm's-length situations, we retain the language from the proposed rule that lessees may not deduct any costs associated with actual or theoretical losses in non-arm's-length oil transportation situations. We will still allow lessees to deduct the actual costs of losses that they incur under arm's-length transportation agreements because the payment is a true out-of-pocket expense to the lessee.

BBB bond rate: ONRR reduced the multiplier on any remaining undepreciated capital costs from 1.3 to 1.0 times the Standard & Poor's BBB bond rate. We moved this provision to § 1206.112(i)(3).

Public Comment: Several companies and industry trade groups opposed modifying the Standard & Poor's BBB bond rate multiplier. Commenters state that ONRR failed to sufficiently analyze rates of return for pipelines and should provide better support for its decision to reduce the multiplier to 1.0. A State supported reducing the multiplier, noting that market fluctuations impact transportation facilities less.

ONRR Response: Modifying the Standard & Poor's BBB bond rate multiplier recognizes changes within the economy since 2005 (including lower interest rates) and creates

consistency with other product valuation guidelines. This rate better reflects the cost of borrowing to finance capital expenditures involved in pipeline construction.

9. Adjustments and Transportation Allowances When Using NYMEX Prices or Alaska North Slope (ANS) Prices for Oil Royalty Value (§ 1206.113)

Eliminating transportation factors: Previously, ONRR allowed lessees to net transportation from their gross proceeds when the lessees' arm's-length contract reduced the price of the oil by a transportation factor. In this final rule, we eliminated this provision and, instead, require lessees to report such costs as a separate entry on Form ONRR-2014. We addressed comments pertaining to this issue, which we detail in § 1206.110, of this Preamble.

10. Reporting Requirements for Arm's-Length Transportation Contracts (§ 1206.115)

Eliminating transportation factors: Eliminating transportation factors will require lessees to report any transportation costs embedded in an arm's-length contract as a separate line entry on Form ONRR-2014.

Public Comment: ONRR received multiple comments indicating industry would suffer significant administrative burdens to extract, separate or "unbundle" transportation costs from their arm's-length sales contracts. The commenters indicated that removing transportation factors will result in "large scale contract review and major changes to accounting systems and processes."

ONRR Response: We recognize that eliminating transportation factors requires lessees to report their transportation costs embedded in an arm's-length contract separately as a transportation allowance, which may require changes in the lessees' reporting systems. However, removing transportation factors increases transparency and helps us verify that such costs are the reasonable and actual costs that lessees incur for transportation. Furthermore, as we mentioned previously, transportation factors may include multiple items embedded in arm's-length sales contracts.

C. Specific Comments on 30 CFR Part 1206—Product Valuation, Subpart D—Federal Gas

1. Calculating Royalty Value for Unprocessed Gas Sold Under an Arm's-Length or Non-Arm's-Length Contract (§ 1206.141)

Dual accounting: Because we removed the dual accounting requirement under proposed § 1206.151, we deleted paragraph (a)(3), which referenced it. We re-numbered proposed paragraph (a)(4) as (a)(3) in this final rule.

First arm's-length sale: In this final rule, ONRR eliminated the non-arm's-length valuation benchmarks and requires lessees to value gas production based on how they sell their gas (*such as* using (1) the first arm's-length-sale prices, (2) optional index prices, or (3) volume weighted average of the values established under this paragraph for each contract for the sale of gas produced from that lease). Under § 1206.141(b)(2), if you sell or transfer your Federal gas production to your affiliate, or some other person at less than arm's-length, and that person or their affiliate then sells the gas at arm's-length, you will base your royalty value on the other person's (or their affiliate's) gross proceeds under the first arm's-length contract. However, two exceptions apply: (1) Lessees may elect to use the index-pricing option under § 1206.141(c) of this section, or (2) we decide to value your gas under the default valuation provision in § 1206.144.

Public Comment: A State and a public interest group supported ONRR's proposal to require lessees to value non-arm's-length dispositions of gas production based on the first arm's-length sale rather than the gas valuation benchmarks.

Industry trade groups suggested that ONRR reword the regulatory language under subsection (b) for clarity. The commenters were concerned that the word "may" and the words "or another person," could lead to misinterpretation of this rule's intent.

ONRR Response: We recognize that the wording under proposed § 1206.141(b) caused some confusion and reworded this paragraph in the final rule.

Public Comment: Several industry commenters asserted that tracing their affiliates' arm's-length gross proceeds is complicated and burdensome. One industry trade group remarked that § 1206.141(b) does not address costs unique to marketing and transporting Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG), where the

first arm's-length sale may be at a distant international market.

ONRR Response: The values established in arm's-length transactions are the best indication of market value. We recognize that changes in industry and the marketplace may make it difficult for a lessee to value its gas using the benchmarks. To address these difficulties, we eliminated the benchmarks in order to provide early certainty and gave lessees with non-arm's-length sales the option to value gas based on the first arm's-length sale or index prices.

Index-based valuation option: ONRR added a new paragraph (c) containing an index-price valuation method that a lessee may elect to use in lieu of valuing its gas under proposed paragraphs (b)(2) and (b)(3). ONRR based the method on publicly-available index prices, less a specified deduction to account for processing and transportation costs. This valuation method also applies to certain "no contract" situations that we describe under paragraph (e).

The index-based option provides a lessee with a valuation option that is simple, certain, and avoids the requirements to unbundle fees and "trace" production. This is applicable when there are numerous non-arm's-length sales prior to an arm's-length sale. Under paragraph (c), the lessee may choose to value its gas only in an area that has an active index pricing point published in an ONRR-approved publication. The lessee may elect to value its gas under this paragraph, making that election binding on the lessee for two years. ONRR will post a list of approved publications at www.onrr.gov.

In this final rule, under paragraph (c), there are three possible scenarios for establishing the index-price point. The first scenario is when you can only transport gas to one index pricing point published in an ONRR-approved publication. In this scenario, your value for royalty purposes is based on that index pricing point.

The second scenario is when you can physically transport gas to more than one index pricing point. In this scenario, you must base your value for royalty purposes on the highest index pricing point to which your gas could flow. For example, assume that you have a lease in the West Delta area of the Gulf of Mexico, and your lease is physically connected by a pipeline to the Mississippi Canyon Pipeline. In this case, your gas is physically capable of flowing to the Toca Plant (through the Southern Natural Gas Pipeline), the Yscloskey Plant (through the Tennessee Gas Pipeline), or the Venice Plant. This

means that you have multiple index pricing points to which your gas can physically flow. Also, assume that the highest reported monthly bidweek price among the multiple index pricing points is the Tennessee Gas 500 Leg Price at the tailgate of the Yscloskey Plant. Finally, assume that you cannot flow your gas through the Tennessee Gas Pipeline (to the Yscloskey Plant) because all available capacity on that pipeline is under contract to other persons, and the pipeline has no capacity available to you for the production month—in other words, it is constrained. In this example, you would use the highest reported monthly bidweek price at the tailgate of the Yscloskey Plant as the value under this paragraph even though your gas did not flow to that index pricing point during that production month.

The third scenario is when there are multiple sequential pricing points on a pipeline through which you could transport your gas. In this scenario, you must base your value for royalty purposes on the first index pricing point after your gas enters that pipeline.

Under paragraph (c), the lessee can only use an index pricing point if it could physically transport its gas to that index pricing point because there is a pipeline or series of pipelines that physically connect to the lease and flow from the lease to the index pricing point. We will exclude the use of index pricing points where a lessee cannot sell its gas.

If the lessee can transport its gas to only one index pricing point, the lessee must base its value under paragraph (c)(1)(i) on the highest reported monthly bidweek price for that index pricing point in the ONRR-approved publication for the production month. If the lessee can transport its gas to more than one index pricing point, the lessee must base its value under paragraph (c)(1)(ii) on the highest reported monthly bidweek price for the index pricing points to which the lessee could transport its gas in the ONRR-approved publication for the production month. However, under paragraph (c)(1)(iii), if there are sequential index pricing points on a pipeline, the lessee must base its value on the first index pricing point at or after the lessee's gas enters the pipeline.

We recognize that index pricing points are normally located off of the lease and, frequently, are at lengthy distances from the lease. Thus, under paragraph (c)(1)(iv), we allow a lessee to reduce the highest reported monthly bidweek price by a set amount to account for transportation costs that a lessee would incur to move the gas from

the lease to an applicable index pricing point. We will allow a lessee to reduce the highest reported monthly bidweek prices by 5 percent for sales from the OCS Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

Paragraph (c)(1)(v) states that, after you select an ONRR-approved publication available at www.onrr.gov, you may not select a different publication more often than once every two years. We will also, under paragraph (c)(1)(vi), exclude individual index prices from this option if we determine that the index price does not accurately reflect the value of production. We will post a list of excluded index pricing points at www.onrr.gov.

Paragraph (c)(2) explains that you may not take any other deductions from the value calculated under this paragraph (c) because you would already receive a reduction for transportation under paragraph (c)(1)(iv).

Public Comment: Public interest groups supported the changes as an overall effort to provide greater clarity and transparency to the valuation process. A State commenter and STRAC opposed using an index-based option for reasons identified below.

While industry commenters supported the idea of an index-based method, they did not support the method as proposed. Industry commenters explained that the proposed index-based method results in a value so far above what is reasonable that few lessees would choose to use it. Commenters argued that using the highest bidweek price results in an inflated value for royalty purposes and is neither reasonable nor justified.

ONRR Response: The value under an index-based valuation option is reasonable and justified because of the benefits that it affords to the lessee. Lessees have the burden of showing that none of the costs that they incur and deduct are costs to place their gas production in marketable condition. *Burlington Res. Oil & Gas Co. LP v. U.S. Dep't of the Interior*, No. 13–CV–0678–CVE–TLW, 2014 WL 3721210, at *12 (N.D. Okla. July 24, 2014). This burden includes separating or “unbundling” costs associated with putting production in marketable condition as discussed in *Burlington*. If the lessee chooses to use the index-based option, it will relieve the lessee of those responsibilities. While this method benefits lessees, it must also protect the interests of the Federal lessor. The index-based valuation method does just that.

Public Comment: Industry commenters argued that the requirement to use the highest index price at a pricing point to which a lessee's gas *could* flow effectively requires a lessee to pay royalty on the highest theoretically obtainable price, even though that price is not, in fact, obtainable. They explained that ONRR cites no authority or justification for this proposed standard. Instead, the commenters suggested that the rule require a lessee to base the value of its gas on the index where the lessee's gas actually flowed.

ONRR Response: This provision protects the interests of the Federal lessor, while also simplifying the royalty reporting process for industry. If this rule required a lessee to calculate royalty on the basis of the index pricing point(s) to which the gas did flow, we would require companies to trace production, potentially through a series of affiliated transactions, and determine what volumes of gas flowed to which index pricing points. This increases the burden for both industry and us. We retained this provision in the final rule because it is consistent with the administrative simplicity that the index-based method seeks to achieve.

Public Comment: Industry commenters stated that the fixed adjustments for transportation are too low and do not reflect current gas transportation rates.

ONRR Response: We analyzed transportation rate data, as we discussed in the Procedural Matters section, and determined that the rates, as proposed, are a reasonable reduction to the index price.

Public Comment: A State commenter expressed concern over the potential manipulation of prices, providing that commercial price bulletins are subject to manipulation and, indeed, have been manipulated.

ONRR Response: We recognize the State's concern, but the index-based valuation method protects the Federal and State royalty interests for the following reasons: (1) Federal Energy Regulatory Commission (FERC) must approve pricing publications, and the publication companies also have protections to prevent and discourage price manipulation; (2) we have the discretion to disallow the use of price points that are not liquid and are more subject to manipulation; (3) we designed the index-based valuation method to generally result in a value higher than gross proceeds because of the simplicity and clarity that it affords to lessees; and (4) index prices are a trusted measure of value in the gas sales industry and the

basis for many arm's-length sales contracts.

Public Comment: STRAC requested that (1) States have the option to “opt in” for index-based valuation (similar to Indian Tribes for Indian gas valuation); (2) there be some “price testing” on the use of these index prices; and (3) there be a “true-up” to ensure that the index-based valuation was higher than a company's gross proceeds.

ONRR Response: The index-based value protects both Federal and State interests. We analyzed Form ONRR–2014 royalty data and compared it to index prices for the years 2007 through 2010. We found that the index price was consistently higher than the average value received under gross proceeds. A rule that allows each State to choose to opt in or requires an annual true-up negates the administrative simplicity and clarity that we intend for the index-based option.

Public Comment: One industry trade group commented that ONRR's proposal would burden small operators with the added expense required to subscribe to an industry price publication, which they believe is an unnecessary cost.

ONRR Response: We note that there is, potentially, an additional expense if a company values their gas under the index-based option. We consider this potential additional expense to be a cost of doing business associated with properly reporting and paying Federal royalties.

Public Comment: Industry commenters strongly urged that the index-based option be available to value arms-length transactions. These commenters noted that the 1995–1996 Federal Gas Valuation Negotiated Rulemaking Committee recommended the same. One industry trade group specifically stated, “ONRR should afford Federal gas lessees the option of using an index-pricing option to value royalties under arm's-length sales to avoid the burden of chasing gross proceeds to distant markets and to obviate the unnecessary step of creating an affiliate simply for the purpose of affording the lessee the regulatory option of choosing index pricing.”

ONRR Response: Gross proceeds under valid arm's-length transactions are the best measure of value. The use of index prices as one option for valuing non-arm's-length transactions is appropriate because of the complex nature of transactions between affiliates and the potential administrative burden of pursuing and supporting the value under the first arm's-length sale. In this final rule, we will not expand the index-based option to arm's-length sales.

No-sale situations: Paragraph (d)(1) provides that, if you have no written contract or no sale of gas subject to this section, and there is an index pricing point for the gas, then you must value your gas under the index-pricing provisions of paragraph (c) of this section unless ONRR values your gas under § 1206.144. We intended this provision to address situations including, but not limited to, when (1) the lessee sells its gas to an affiliate, and the affiliate uses the gas in its facility; (2) the lessee sells its gas to an affiliate, the affiliate resells the gas to another affiliate of either the lessee or itself, and that affiliate uses the gas in its facility; (3) the lessee uses the gas as fuel for its other leases in the field or area; or (4) the lessee delivers gas to another person as payment for an overriding royalty interest that the other person holds.

Public Comment: A commenter noted that lessees do not sell gas used or lost along the pipeline and may currently value those volumes under the benchmark valuation regulations. The commenter stated that, previously, using the price that the lessee received for the gas that it sold as the basis to value its gas used or lost along the pipeline was a much more certain method of valuing gas, which also satisfied benchmark two. Instead, the commenter argues that the rule requires the lessee to submit a proposed valuation method and be subject to having to make retroactive changes if ONRR does not accept the proposed method. The commenter argued that it was unfair to require lessees who cannot otherwise use the index-based option (those making arm's-length sales) to have to use the index-based pricing to value gas used or lost along a pipeline and adds unnecessary complexity.

ONRR Response: We thank this commenter for the insightful comment. We acknowledge that the proposed rule was not clear in providing a method for a lessee to use to value its gas used or lost along a pipeline prior to sale and disallowed fuel used in a gas plant. To add clarity and simplicity, we renumbered the proposed paragraph (d) to paragraph (e). For the new paragraph (d), we inserted new language that allow the lessee to value this gas for royalty purposes using the same royalty valuation method for valuing the rest of the gas that the lessee sells.

In addition to the four situations above, and in the preamble to the proposed rule, we note that the lessee should use new paragraph (e) when the lessee is required to pay royalty on vented, flared, or otherwise lost gas as the BLM or Bureau of Safety and

Environmental Enforcement (BSEE) determined.

Public Comment: A company stated that the proposed regulation does not provide a method to value its gas when the lessee did not sell its gas but, rather, used it on site to generate electricity. It also argued that eliminating the fourth benchmark (netback) in the previous rule could negatively affect lessees that use gas to generate electricity because an index price is not an accurate indicator of market value.

ONRR Response: We disagree with the comment because this final rule addresses the situation wherein a lessee does not sell its gas because the gas is used on site to generate electricity under § 1206.141(e). This paragraph provides that, where there is no sale of the gas and there is not an active index pricing point, we will value your gas under § 1206.144(f).

2. Calculating Royalty Value for Processed Gas Sold Under an Arm's-Length or Non-Arm's-Length Contract (§ 1206.142)

Percentage-of-Proceeds (POP) contracts: Paragraph (a)(2) applies to situations where a lessee sells its gas before processing and must base their royalty payment on any constituent products, resulting from processing, such as residue gas, NGLs, sulfur, or carbon dioxide. This final rule requires lessees to value POP contracts, percentage-of-index contracts, and contracts with any variations of payment based on volumes or the value of those products as processed gas.

Public Comment: Commenters from industry, industry trade groups, and STRAC opposed this change. Industry commenters and STRAC focused their comments on the reporting burden and financial impact of this change. One commenter explained, "Because POP contracts have, since, November of 1991 been subject to the unprocessed gas valuation regulations, many companies do not have accounting systems set up to report anything other than a single product code 04 line." The commenters explain that this proposed change would impose significant accounting system costs and delays in reporting.

One company stated that the current regulations recognize that the lessee no longer has title to or control over production after its POP buyer takes possession at the wellhead or plant inlet, highlighting that the lessee is not obligated to place residue gas and plant products in marketable condition. It believes that, by treating arm's-length POP contracts as sales of processed gas, ONRR improperly places the burden on the lessees to bear the costs to place

residue gas and plant products in marketable condition despite the fact that the lessees do not have title to or control over same.

ONRR Response: We understand that this change may increase the number of reported lines and may require some companies to adjust their systems. Yet, if a company is in compliance under the previous rules (not taking more than the allowance limits without approval, adding back costs associated with placing the gas into marketable condition, adding back marketing fees, etc.), this change should not be overly burdensome. This change increases data transparency, more accurately values the products sold under these types of sales contracts, and allows us to better monitor allowances and account for royalty interest more quickly and accurately.

Contrary to the commenter's assertions, past regulations did place the responsibility on lessees who sell their gas at the wellhead under POP-type contracts to place the residue gas and gas plant products into marketable condition at no cost to the Federal government. Simply selling the gas at the wellhead does not mean that the gas is in marketable condition—one must look to the requirements of the main sales pipeline. The U.S. District Court for the Northern District of Oklahoma supported ONRR's position under the past regulations, finding that, "Whether gas is marketable depends on the requirements of the dominant end-users, and not those of intermediate processors" *Burlington Res. Oil & Gas Co. LP v. U.S. Dep't of the Interior*, No. 13–CV–0678–CVE–TLW, 2014 WL 3721210, at *11 (N.D. Okla. July 24, 2014).

Valuation of keepwhole contracts: Paragraph (a)(3) states that the lessee must value gas processed under a "keepwhole" contract as processed gas. Under § 1206.20, we define the term "keepwhole contract" as a processing agreement under which the processor compensates the lessee by delivering to the lessee a quantity of residue gas (after processing) that is equivalent to the quantity of gas the processor received (prior to processing), normally based on heat content, less gas used as plant fuel and gas that is unaccounted for and/or lost. The lessee does not receive NGLs under these contracts. We often find that lessees are confused about how to value, for royalty purposes, gas processed under such contracts and then sold. This provision clarifies that a lessee must value gas processed under a keepwhole contract as processed gas. That is, royalty is based on 100 percent of the value of residue gas, 100 percent

of the value of gas plant products, plus the value of any condensate recovered downstream of the point of royalty settlement prior to processing, less applicable transportation and processing allowances.

Public Comment: Commenters from industry trade groups and STRAC opposed this provision. They believe that ONRR should eliminate the requirement to report gas processed under a keepwhole contract as processed gas. The industry trade groups explained that companies do not have the data to report keepwhole contracts as processed gas. STRAC added that valuing keepwhole contracts as processed gas does not, in their experience, result in additional revenue collections, but it requires a significant amount of work for both auditors and industry.

ONRR Response: Our regulations require lessees to base their royalties for gas sold after processing on the values of condensate, residue gas, and gas plant products resulting from processing gas produced from a Federal lease. Lessees sell gas processed under keepwhole contracts after processing, and, therefore, lessees should value their gas as such. This requirement also protects the public from hidden processing deductions that the lessee takes that may exceed the 66⅔ percent limit of the value of the NGLs. Additionally, numerous entities rely on and scrutinize our data, making accurate reporting essential.

To aid lessees in their effort to properly compute royalties for gas processed under a keepwhole contract, we published a reporter letter dated November 21, 2012 (Reporter Letter). The Reporter Letter provided guidance on how to report keepwhole contracts, including instructions for situations where the lessee receives no NGL volume or value data. It is important to note that, in most cases, this requirement does not increase the royalties that a lessee pays because the lessee may include the difference in value between the gallons of NGLs that the plant recovered and the MMBtu-equivalent of the NGLs returned to the producer in its processing allowance.

First arm's-length sale: In this final rule, ONRR eliminated the non-arm's-length valuation benchmarks. Instead, this final rule requires lessees to value residue gas and gas plant products based on how they sell their residue gas and gas plant products (such as using (1) the first arm's-length-sale prices, (2) optional index prices, or (3) volume weighted average of the values established under this paragraph for each contract for the sale of gas

produced from that lease). Under § 1206.142(c)(2), if you sell or transfer your Federal residue gas and gas plant products to your affiliate, or some other person at less than arm's-length, and that person or its affiliate then sells the residue gas and gas plant products at arm's-length, royalty value will be the other person's (or its affiliate's) gross proceeds under the first arm's-length contract. However, two exceptions apply: (1) Lessees may elect to use the index-pricing option under § 1206.142(d) of this section, or (2) ONRR decides to value your residue gas and gas plant products under the default valuation provision in § 1206.144.

Public Comment: ONRR received comments from a State and a public interest group supporting ONRR's proposal for lessees to value non-arm's-length dispositions of residue gas and gas plant products based on the first arm's-length sale rather than the benchmarks contained in the previous rule. Several industry commenters asserted that tracing their affiliates' arm's-length gross proceeds is complicated and burdensome. One industry trade group remarked that § 1206.142(c) does not address costs unique to marketing and transporting CNG and LNG, where the first arm's-length sale may be at a distant, international market.

ONRR Response: The values established in arm's-length transactions are the best indication of market value. We recognize that changes in industry and the marketplace may make it difficult for a lessee to value its gas using the benchmarks. To address these difficulties, we eliminated the benchmarks to provide early certainty and gave lessees with non-arm's-length sales the option to value gas based on the first arm's-length sale or index prices.

Index-based valuation option: Paragraph (d)(1) applies to residue gas. It has the same index-price option as § 1206.141(c)(i) through (vi). We discuss using index pricing points in § 1206.141 of this Preamble.

Paragraph (d)(2) contains the index-based pricing option for NGLs. Under paragraph (d)(2)(i), if you sell NGLs in an area with one or more ONRR-approved commercial price bulletins available at www.onrr.gov, you may choose one bulletin, and your value for royalty purposes would be based on the monthly average price for that bulletin for the production month. We consider you to be selling NGLs in an area with an ONRR-approved commercial price bulletin if actual sales of NGLs that the plant processing your gas recovers are made using NGL prices in an ONRR-

approved commercial price bulletin. For example, in our experience, actual sales of NGLs recovered in plants in New Mexico commonly reference Mont Belvieu, Texas, prices in Platts, while actual sales of NGLs recovered in plants in certain parts of Wyoming reference Mont Belvieu, Texas, or Conway, Kansas, prices. If you process your gas at one of these plants with these types of actual sales arrangements, we will consider you to be selling NGLs in an area with an ONRR-approved commercial price bulletin. In that case, you may elect to value your NGLs using the index-price method if your NGLs meet the requirements for using that method. We will monitor actual sales of NGLs and eliminate any area where an active market using NGLs prices in an ONRR-approved commercial price bulletin ceases to exist.

Under paragraph (d)(2)(ii), you may reduce the index-based value that you calculate under paragraph (d)(2)(i) by a specified amount to account for a theoretical processing allowance and Transportation and Fractionation (T&F). Therefore, the reduction includes two components that we calculated: (1) An allowance based on processing allowance information lessees report to us and (2) T&F based on our review of gas plant contracts and gas plant statements.

For the processing allowance component, ONRR examined processing allowances that lessees and others reported from January 2007 through October 2011. We segregated the data into two subsets: (1) The Gulf of Mexico (GOM) and (2) onshore Federal leases and OCS leases other than those in the GOM. We segregated the leases geographically because the GOM is closer to major market centers at Mont Belvieu, Napoleonville, and Geismar/Sorrento and, generally, has its own processing, transportation, and fractionation regimen that is distinct from the rest of the country. It is not fair or accurate to benchmark processing for the entire country based on the economics of GOM processing.

We could not segregate non-arm's-length processing allowances because lessees do not identify processing allowances as arm's-length or non-arm's-length when they report to ONRR. Rather, we calculated a weighted-average cents-per-gallon processing allowance by month for both GOM and all other Federal leases. Using the weighted average cents-per-gallon processing allowance that we calculated, we determined the average allowance rate over the five-year period, along with the maximum and minimum monthly rates as follows:

	GOM (¢/gal)	Other (¢/gal)
Average Rate	17	22
Maximum Rate	29	32
Minimum Rate	10	15

Because we intend for this option to provide a simple method for us to calculate and provide to lessees, we used the minimum, rather than the average rate, for the processing allowance portion of the deduction. For

both the GOM and all other Federal leases, the minimum rate is seven cents less than the average rate. We find that (1) the minimum allowance best protects the public interest and (2) a lessee experiencing higher allowable costs than this rate does not have to elect to use this option and the lower cost allowance. Moreover, seven cents is a reasonable tradeoff given the simplicity, certainty, and commensurate administrative savings that this option would provide to a lessee.

For the T&F part of the reduction, we examined contracts that specified T&F. If contracts did not specify T&F, we looked at the gas plant statements. If the statements listed T&F as a line item, we used that line item as the T&F. If the statements did not list T&F as a line item, we calculated the difference between the price on the plant statement and an appropriate published price to approximate the T&F. We then averaged these T&F costs for GOM, New Mexico, and other, as follows:

	GOM	New Mexico	Other
Average T&F	5¢/gal	7¢/gal	12¢/gal.

We broke out New Mexico because the T&F fees for New Mexico plants were consistently around seven cents per gallon and were considerably less

than for other onshore plants. We then added the processing allowances that we calculated and the T&F. Based on the five years of data discussed above,

we calculated that the total NGLs reductions that lessees could use under this option are as follows:

	GOM	New Mexico	Other
NGLs Deduction	15¢/gal	22¢/gal	27¢/gal.

Under paragraph (d)(2)(ii), rather than publish the reductions in the CFR, we will post the reductions at www.onrr.gov for the geographic location of your lease. ONRR will calculate the reductions using the method explained above. This process will give us the flexibility to quickly recalculate and provide revised reductions to lessees in response to market changes. This method is binding on you and us. Under paragraph (d)(4), we will update the allowable reductions periodically using this method and post changes at www.onrr.gov.

Paragraph (d)(2)(iii) explains that, after you select an ONRR-approved commercial price bulletin available at www.onrr.gov, you may not select a different commercial price bulletin more often than once every two years. Under paragraph (d)(3), you may not take any other deductions from the value that you used under this paragraph (d) because it already includes reductions for transportation and processing.

Paragraph (e) mirrors § 1206.141(d); this explains how you must value certain volumes of processed gas or NGLs that are used as fuel, lost, or retained as a fee under the terms of a sales or service agreement.

Paragraph (f) mirrors § 1206.141(e); this explains how you must value your processed gas and NGLs if you have no written contract for the sale of gas or no sale of the gas subject to this section.

Public Comment: Several industry commenters noted that ONRR provided no adjustment to the index price for

transportation of the NGL component of the gas stream from the wellhead to the gas plant. The only adjustment is for the costs of transporting and fractionating the recovered NGLs. One commenter suggested that ONRR use the same adjustment that ONRR used in calculating the index-based value for the unprocessed or residue gas (10 percent, but not less than 10 cents per MMBtu or more than 30 cents per MMBtu).

ONRR Response: We do not agree that an adjustment is necessary. The adjustment would be small, and not including it is fair considering our use of the average index price instead of the high index price. This final rule does not require a lessee to use the index option, but the lessee can elect to base its royalty value on the first arm's-length sale.

Public Comment: One industry trade group requested that ONRR clarify whether we intend to use the "average highest price" or the "average average price" for the index-based valuation method for NGLs.

ONRR Response: In our experience, NGL price publishers publish an average and high NGL price. They do not publish an "average average" or "average high" price. We will use the average index price.

Public Comment: One industry trade group commented that New Mexico producers were particularly disadvantaged by the T&F rates that ONRR proposed.

ONRR Response: Our experience indicates that seven cents per gallon is

a reasonable estimate for T&F rates in New Mexico. T&F rates are generally lower in New Mexico than in the rest of the country because New Mexico producers have more direct access to Mont Belvieu, Texas.

Public Comment: An industry commenter questioned what remedy a lessee would have if ONRR did not follow the method set forth in the preamble. The commenter noted that the proposed regulation provided that an election to use index-based pricing cannot be changed more often than once every two years. Then the commenter suggested that it is hard for a company to make an election when the basis for making the election, including ONRR's posting of the amounts that can be deducted, can be changed during the two-year period for which the election was made.

ONRR Response: The two-year election period offers sufficient protection for lessees if we change the rates. Any changes to rates will be based on changes to the markets, which should generally correspond to changes that producers would see if they were reporting gross proceeds.

No-sale situations: Paragraph (e)(1) provides that, if you have no written contract or no sale of gas subject to this section and there is an index pricing point for the gas, then you must value your gas under the index-pricing provisions of paragraph (d) of this section unless ONRR values your gas under § 1206.144. We intended this

provision to address situations including, but not limited to, when (1) the lessee sells its gas to an affiliate, and the affiliate uses the gas in its facility; (2) the lessee sells its gas to an affiliate, the affiliate resells the gas to another affiliate of either the lessee or itself, and that affiliate uses the gas in its facility; (3) the lessee uses the gas as fuel for its other leases in the field or area; or (4) the lessee delivers gas to another person as payment for an overriding royalty interest that the other person holds.

Public Comment: A commenter noted that lessees do not sell gas or gas plant products used or lost along the pipeline and may currently value those volumes under the benchmark valuation regulations. The commenter stated that, previously, using the price that the lessee received for the gas that it sold as the basis to value its gas used or lost along the pipeline was a much more certain method of valuing gas, which also satisfied benchmark two. Instead, the commenter argues that the rule requires the lessee to submit a proposed valuation method and be subject to having to make retroactive changes if ONRR does not accept the proposed method. The commenter argued that it was unfair to require lessees who cannot otherwise use the index-based option (those making arm's-length sales) to have to use the index-based pricing to value gas or gas plant products used or lost along a pipeline and adds unnecessary complexity.

ONRR Response: We thank this commenter for the insightful comment. We acknowledge that the proposed rule was not clear in providing a method for which a lessee shall value gas used or lost along a pipeline prior to sale and disallowed fuel used in a gas plant. In an effort to add clarity and simplicity, we will, therefore, renumber the proposed paragraph (e) to paragraph (f). For the new paragraph (e), we inserted new language that allows the lessee to value this gas for royalty purposes using the same royalty valuation method for valuing the rest of the gas that the lessee sells.

3. Determination of Correct Royalty Payments (§ 1206.143)

Default: ONRR added a default valuation provision that allows us to value your gas, residue gas, or gas plant products under § 1206.144 or any other provision in this subpart D. We addressed comments pertaining to the “default provision” paragraph, which we detail in § 1206.101, of this Preamble.

Public Comment: All of the commenters who addressed the default provision under Federal oil had the

same comments for Federal gas, and we will not repeat them here. Please refer to the public comments for Federal oil for an overall discussion of the default provision.

Specifically for gas, several commenters stated that ONRR lists comparability factors in its valuation method that contradict what ONRR permits lessees to consider. They state, for example, that ONRR may look to the value of like-quality gas, residue gas, or gas plant products in the same or nearby fields or plants, but it is not permitting lessees the option to use these standards as part of their valuation processes in the first instance.

ONRR Response: We will only respond, here, to those comments that are specific to gas, residue gas, and gas plant products. For a broader response to the default provision, because it also relates to Federal gas, please see ONRR's response to Federal oil, which we detail in § 1206.101, of this Preamble.

We disagree with commenters that state that we list comparability factors in our default valuation method that contradict what we permit the lessees to consider. Valuation, first and foremost, is generally based on the gross proceeds accruing to the lessee under an arm's-length contract or received under the first arm's-length sale following a sale to an affiliate. Only in rare situations, when normal valuation methods are not viable or there has been other extenuating circumstances, will we defer to the valuation criteria listed in § 1206.144.

This final rule delineates factors that we may consider if we decide to determine the value of natural gas for royalty purposes under the default provision. Those factors may include, but are not limited to the following: the value of like-quality gas in the same field or nearby fields or areas; the value of like-quality residue gas or gas plant products from the same plant or area; public sources of price or market information that we deem to be reliable; information available or reported to us, including but not limited to, on Form ONRR-2014 and Form ONRR-4054; costs of transportation or processing, if we determine that they are applicable; and any information that we deem relevant regarding the particular lease operation or the salability of the gas.

Misconduct: ONRR added a new definition for the term misconduct. We addressed comments pertaining to this definition, which we detail in § 1206.20, of this Preamble.

4. Determination of gas value for royalty purposes (§ 1206.144)

Default: ONRR added a default valuation provision which allows us to value your gas under § 1206.144 or any other provision in this subpart. We addressed comments pertaining to the “default provision” paragraph, which we detail in § 1206.101, in this Preamble.

Area: ONRR removed the phrase “legal characteristics” from the definition of area. We addressed comments pertaining to this definition and the regulations that it affects, detailed in § 1206.105, in this Preamble.

5. Responsibility To Market Production and To Place Production into Marketable Condition (§ 1206.146)

Public Comment: Although ONRR did not modify the wording in this section, several commenters argue that our proposal eliminates separately defined requirements for processed and unprocessed gas and replaces them with a consolidated marketable condition requirement. This, commenters argue, may result in the lessee being required to place processed gas in marketable condition twice—once as gas and again as residue gas.

ONRR Response: The regulations have always required the lessee to put its production into marketable condition at no cost to the Federal government. This requirement remains unchanged, as does a lessee's duty to put its production into marketable condition.

6. Valuation determination requests (§ 1206.148)

Guidance and Determinations: ONRR clarified how a lessee may request a valuation determination from us. We addressed comments pertaining to guidance and determinations in § 1206.108. For the reasons discussed in response to comments, we deleted the words “or guidance” from the title and paragraph (a) of this section.

7. Accounting for Comparison (§ 1206.151)

ONRR proposed to move the current provisions under § 1206.155 to proposed § 1206.151 and requested comments regarding whether or not to retain the requirement to perform accounting for comparison (dual accounting) for gas produced from Federal leases.

Public Comment: Industry and State commenters supported removing the Federal dual accounting provision from the regulations. Commenters stated that, because residue gas is now valued based on the first arm's-length sale or index-based option, the criteria that triggered

dual accounting, a non-arm's-length sale of residue gas after processing, is no longer valid.

STRAC agreed that, under current market conditions, accounting for comparison was no longer necessary, but they questioned how ONRR would respond to potential changes in the gas market in the future.

ONRR Response: We removed the requirement to perform accounting for comparison for gas produced from Federal leases from the final rule. We agree that the gas valuation method under § 1206.142 renders accounting for comparison for Federal gas production unnecessary. Should significant changes in the gas market occur in the future, we will revisit the need for Federal dual accounting in a future rulemaking. Further, § 1206.140(c) recognizes the primacy of lease terms over regulations and, should the terms of a lease require dual accounting, lessees are clearly subject to the dual accounting requirement.

8. General Transportation Allowance Requirements (§ 1206.152)

Subsea gathering: ONRR added a new provision stating that you may not take a transportation allowance for the movement of gas produced on the OCS from the wellhead to the first platform. This addition, along with the changes to the definition of gathering, rescinds the Deep Water Policy. We addressed comments pertaining to this issue, which we detail in § 1206.110, in this Preamble.

Fifty-percent allowance cap and retroactive change: ONRR eliminated the regulation allowing us to approve transportation allowances in excess of 50 percent of the value of a lessee's gas production. Any prior approvals will terminate on the date when the rule becomes final. We addressed comments pertaining to these issues, which we detail in § 1206.110, in this Preamble.

Eliminating transportation factors: Previously, ONRR allowed lessees to net transportation from their gross proceeds when the lessees' arm's-length contract reduced the price of the gas by a transportation factor. We eliminated this provision and, instead, require lessees to report such costs as a separate entry on Form ONRR-2014. We addressed comments pertaining to this issue, which we detail in § 1206.110, in this Preamble.

Misconduct: ONRR added a new definition for the term "misconduct." We addressed comments pertaining to this issue, which we detail in § 1206.20, in this Preamble.

Default: We addressed comments pertaining to the "default provision"

paragraph, which we detail in § 1206.101, in this Preamble.

Unreasonably high transportation costs: We addressed comments pertaining to this issue, which we detail in § 1206.104, in this Preamble.

9. Determination of Transportation Allowances for Arm's-Length Transportation Allowances (§ 1206.153)

Pipeline losses: We addressed comments pertaining to this issue, which we detail in § 1206.111, in this Preamble.

In the proposed rule, we removed the provision in the previous regulations under § 1206.157(b)(5). We neglected to remove regulatory language in proposed § 1206.153(b)(7). Therefore, in this final rule, we deleted, "or ONRR approves your use of a FERC or State regulatory-approved tariff as an exception from the requirement to calculate actual costs under § 1206.154(l) of this subpart."

Written contracts: We added a new provision stating that we will determine transportation allowances if lessees do not have a written contract for the arm's-length transportation of gas. We addressed comments pertaining to this issue, which we detail in § 1206.104, in this Preamble.

Eliminating transportation factors: Previously, we allowed lessees to net transportation from their gross proceeds when the lessees' arm's-length contract reduced the price of the gas by a transportation factor. We eliminated this provision and alternatively require lessees to report such costs as a separate entry on Form ONRR-2014. We addressed comments pertaining to this issue, which we detail in § 1206.110, in this Preamble.

Boosting: Under paragraph (c)(8), we specify that the costs of boosting residue gas are not allowable costs of transportation.

Public Comment: An industry commenter argued that this new provision effectively requires the unbundling of arm's-length transportation agreements. Industry also argues that the additional disallowance of boosting residue gas in this section and in § 1202.151(b) is either redundant or results in the lessee having to pay for some marketable condition costs twice for processed gas. Industry states that boosting residue gas is part of plant costs, and it is not associated with a transportation system or transportation allowance.

An industry commenter suggested that eliminating the proposed boosting language in paragraph (c)(8) will ensure consistency in product valuation for all natural gas, whether processed, unprocessed, conventional, or coal bed

methane and all plants (cryogenic, lean oil absorption, refrigeration, and CO₂ removal). According to the commenter, elimination of the boosting language will also ensure proper treatment involving leases that produce at a pressure above the marketable condition requirement or for offshore leases where the gas leaves the production platform at or above the marketable condition pressure by requiring the gas be placed into marketable condition only once.

ONRR Response: Current regulations and case law make clear that the cost incurred—including any fuel used—to boost gas (such as compress residue gas after processing) is not a deductible cost of processing or transportation (30 CFR 1202.151(b); see also *Devon Energy Corporation v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 86 (2009), (finding that boosting is not deductible even if gas is in marketable condition before entering a gas processing plant)). Yet a number of members of industry continue to deduct costs incurred to boost residue gas as either a processing or a transportation allowance, and they argue that it is proper to do so. The inclusion of paragraph (c)(8) reinforces current regulations and case law and therefore we retained it in the final rule.

10. Determination of Transportation Allowances for Non-Arm's-Length Transportation Contracts (§ 1206.154)

Pipeline losses: Under paragraph (c)(2)(ii), we eliminated the provision that allows lessees to deduct the costs of pipeline losses, both actual and theoretical, under non-arm's-length transportation situations. We addressed comments pertaining to this issue, which we detail in § 1206.111, in this Preamble.

BBB bond rate: We reduced the multiplier on any remaining undepreciated capital costs from 1.3 to 1.0 times the Standard & Poor's BBB bond rate. We addressed comments pertaining to this issue, which we detail in § 1206.112, in this Preamble.

FERC or state-regulatory-agency approved tariffs: We removed the provisions allowing a lessee with a non-arm's-length contract to apply for an exception to use FERC or State-regulatory-agency approved tariffs as an exception from the requirements to calculate actual costs.

Public Comment: Several companies and industry trade groups opposed removing the provision, stating that it lacked justification. One commenter stated, "Many of these situations involve affiliated pipelines where obtaining the information to do these calculations would be problematic and

burdensome due to the governmental restrictions placed on pipeline companies in sharing information with shippers.”

ONRR Response: Lessees may deduct their reasonable actual costs of transportation under this section. The burden lies with the lessee to calculate these reasonable actual costs of transportation. We removed this rarely-used provision to apply for an exception to create consistency with the Federal oil valuation regulations and promote a more consistent application of the actual cost allowance method.

11. Reporting Requirements for Arm's-Length Transportation Contracts (§ 1206.155)

Eliminating transportation factors: Eliminating transportation factors will require lessees to report any transportation costs embedded in an arm's-length contract as a separate line entry on Form ONRR-2014. We addressed comments pertaining to this issue, which we detail in § 1206.115, in this Preamble.

12. Reporting Requirements for Arm's-Length Transportation Contracts (§ 1206.156)

In the proposed rule, we removed the provision in the previous regulations under § 1206.157(b)(5). We neglected to remove regulatory language in proposed § 1206.156(d). Therefore, in this final rule, we deleted this paragraph.

13. Processing Allowances (§ 1206.159)

We eliminated the regulation allowing us to approve processing allowances in excess of 66⅔ percent of the value of a lessee's gas production. Any prior approvals will terminate on the date when the rule becomes final. We addressed issues related to prior approval terminations, which we detail in § 1206.110, in this Preamble.

Public Comment: We received comments from States and public interest groups generally supporting eliminating ONRR approval to exceed the 66⅔-percent allowance cap on processing allowances. However, a State commenter asserted that the 66⅔-percent cap, itself, was too broad. A State suggested that ONRR calculate allowance caps for each State and use a percentage based on the average processing costs in each State over a ten-year period. A State commenter suggested that ONRR update and post such percentages on its Web page.

ONRR received comments from companies and industry trade groups opposing the proposed rule's elimination of ONRR approval to exceed a 66⅔-percent limitation on processing

allowances. These commenters generally stated that the right to request approval to exceed the 66⅔-percent limitation needs to be reinstated because its removal denies a lessee the ability to deduct all of its actual, reasonable, and necessary processing costs when those costs exceed 66⅔ percent. The commenters believe that this is especially true when the physical make-up of the gas warrants complex plant designs that result in higher costs. Last, commenters take issue with ONRR terminating any approval that it previously issued for a lessee to exceed the 66⅔-percent limitation.

ONRR Response: The comments regarding the 66⅔-percent processing allowance mirror the comments that we received for the 50-percent limitation on transportation allowances for oil. Please refer to our comments regarding the “Fifty-percent allowance cap,” which we detail in § 1206.110, in this Preamble.

Extraordinary processing allowances and retroactive changes: We eliminated the provision that allows a lessee to request an extraordinary processing cost allowance. We previously allowed lessees to deduct processing costs up to 99 percent of the value of the gas plant products extracted and up to 50 percent of the value of the residue gas. This final rule also terminates the two existing extraordinary processing cost allowance approvals. We addressed issues related to the prior approval terminations, which we detail in § 1206.110, in this Preamble.

Public Comment: Industry commenters and a State commented that ONRR should retain the extraordinary processing cost allowance provision and argued that ONRR failed to provide specific evidence that circumstances or improvements in technology have changed enough to warrant the termination of the two existing approvals.

ONRR Response: The Department added the extraordinary processing cost allowance provision to the 1988 regulations to account for the costs of processing unique gas streams based on the technology available at that time. The Department has not approved an extraordinary processing cost allowance since 1996, and we maintain that the markets and the technology have changed sufficiently such that this provision and these approvals are no longer necessary.

Default: In drafting this final rule, we did not include the default provision in this section. We intended to include the default provision here as evidenced by our discussion of the default provision in the economic analysis of the

proposed rule. Therefore, we added the default provision in § 1206.159(e), which applies to processing allowances calculated under §§ 1206.160 and 1206.161. We addressed comments pertaining to the “Default Provision” paragraph, which we detail in § 1206.101, in this Preamble.

14. Processing Allowances Under an Arm's-Length Contract (§ 1206.160)

Unreasonably high processing costs: We moved the requirements for non-arm's-length processing allowances to a separate § 1206.161. Because the requirements for determining processing allowances under an arm's-length contract are essentially the same as those for determining transportation allowances under an arm's-length contract, we made the same changes to processing allowances in this section as those that we made for arm's-length transportation allowances. Newly added paragraph (c) applies if you have no written contract for arm's-length processing of gas. In that case, we will determine your processing allowance under § 1206.144. We addressed comments pertaining to this general issue, which we detailed under § 1206.104, in this Preamble.

Misconduct: We added a new definition for the term misconduct. We addressed comments pertaining to this issue, which we detailed under § 1206.20, in this Preamble.

Default: We addressed comments pertaining to the “default provision,” which we detail under § 1206.101, in this Preamble. In conjunction with our additions in § 1206.159(e) explained above, and to make this section consistent with the transportation allowances sections, we deleted paragraph (a)(3).

D. Specific Comments on 30 CFR Part 1206—Product Valuation, Subpart F—Federal Coal

1. Calculating Royalty Value for Coal I or My Affiliate Sell(s) Under an Arm's-Length or Non-Arm's-Length Contract (§ 1206.252)

Index prices for coal lessees that do not sell under arm's-length contracts: In contrast to the Federal oil and gas valuation regulations, the coal regulations do not allow lessees that do not sell their coal under arm's-length contracts to value their coal based on index prices.

Public Comment: ONRR received comments from industry trade groups, public interest groups, individual commenters, and companies suggesting that ONRR provide coal lessees who do not sell coal under arm's-length

contracts the option of valuing coal based on index prices, similar to the options for oil and gas lessees. The commenters believe that using an index price would provide simplicity, predictability, and transparency to the value of coal not sold under arm's-length contracts. ONRR received a comment from a Tribe indicating that it would be willing to accept index prices as a floor value of coal if there is a reliable index. Several commenters proposed that ONRR could generate an index to value coal not sold at arm's-length.

ONRR Response: We appreciate the comments, but declined to provide lessees who do not sell their coal under arm's-length contracts the option to use index prices to value their coal. As mentioned in the "General Comments" section, we are not aware of any published index prices for coal that cover a wide array of coal production. Currently, there are few, if any, indexes for coal, and they are not as widely used as they are for oil and gas. Also, although the existing indexes vary depending on MMBtu content, they do not take into account other variations in the quality of coal, such as ash or sulfur content.

As to the comments that we should generate an index price for lessees to use, we decline to do so at this time. First, as mentioned above, there are no reliable indexes for coal like there are for oil and gas, making it difficult for us to create index-based prices similar to those used in our Indian oil and gas regulations. Second, if we use arm's-length sales from the royalty reports that we receive, we risk divulging proprietary data. We will monitor the coal market and may be open to considering an index-based valuation option if the indexes become viable in the future.

First arm's-length sales: Consistent with how we require lessees to value other commodities, we are requiring lessees to value non-arm's-length dispositions of Federal coal at the first arm's-length sale.

Public Comment: ONRR received numerous comments on our proposal to remove the benchmarks and, instead, value coal at the first arm's-length sale. Many industry commenters petitioned ONRR to retain the previous rule's benchmark system to value coal sold under non-arm's-length contracts. Some commenters felt that valuing coal at the first arm's-length sale was unnecessarily complex. The commenters stated that using the first arm's-length sale as value may require the lessee to use international or electricity sales as the basis of value, which does not reflect

the value of coal sold at the lease. Instead, some commenters generally expressed a view that the previous rule's benchmark system, or some modification thereof, would be a better option to determine value. Some commenters felt that the first benchmark, which requires lessees to compare their non-arm's-length sales with arm's-length sales in the same field or area, is the appropriate measure of value for coal not sold at arm's-length. In contrast, other commenters felt that the proposed rule did not go far enough. Instead, these commenters recommended that ONRR value the coal based on its final—not its first—arm's-length sale.

ONRR Response: The values established in arm's-length transactions are the best indication of market value. There is ample evidence that arm's-length sales provide a consistent and accurate measure of all commodities for which we collect royalties. We found that the benchmarks were difficult to use in practice. There have been disputes over comparable sales, which benchmark to use, and how to properly apply those benchmarks. To address these difficulties, we simplified the rule by requiring lessees to value coal based on the first arm's-length sale.

Previously, when lessees sold coal under a non-arm's-length contract, the regulations required the lessee to use the first applicable "benchmark" to establish value. The first benchmark was the gross proceeds accruing to the lessee under its non-arm's-length sale, provided those gross proceeds were comparable to the gross proceeds that accrued to other producers not affiliated with the lessee under arm's-length sales of like-quality coal in the same area. To compare such sales, the lessee looked at prices, timing, markets, quality, and quantity of coal. The second benchmark was prices reported to a public utility commission. The third was prices reported to the Energy Information Administration (EIA) of the Department of Energy. The fourth benchmark required the lessee to use other relevant matters, including spot market prices, or other information concerning the particular lease operation or salability of the coal. The fifth benchmark was a netback method.

Although many commenters advocated for the first benchmark, industry and ONRR found it difficult to implement this provision. Acquiring arm's-length contracts to compare with the lessee's gross proceeds was challenging and, at times, impossible for lessees. Lessees cannot use their or their affiliates' comparable sales. Only in rare circumstances did the lessee have

access to its competitor's information regarding the price that the competitor receives for its coal. Further, we cannot obtain or verify contracts for comparable-quality coal sold from fee or State lands. Industry and ONRR also found that it was difficult to ascertain definitively which arm's-length coal sales were comparable and which ones were not. Based on our experience, arm's-length sales are a superior indicator of value to the remaining benchmarks.

Valuing coal sold by coal cooperatives: Section 1206.252(c) addresses sales by coal cooperatives to their members or between members. In keeping with our intent to value commodities, whenever possible, at their first arm's-length sale, we provided a definition of the term "*coal cooperatives*" in § 1206.20 and addressed sales by coal cooperatives to their members or between members in this section. Principally, coal cooperatives are formed because of some degree of mutual economic or other business interest. Consequently, transactions within coal cooperatives lack the opposing economic interests characteristic of arm's-length sales. Because coal cooperatives engage in non-arm's-length sales to and between members, we require lessees to base the value of their coal at the first arm's-length sale, wherever that may finally occur. In some cases, this may be the sale of electricity generated in a coal-fired plant.

Public Comment: ONRR received comments supporting our distinction of coal cooperatives as engaging in other than arm's-length sales. These commenters expressed concerns that coal producers, logistics companies, and even generators of coal-fired electricity would take advantage of their affiliated status and sell coal to each other at less than market prices, thereby lowering their royalty liabilities. Conversely, numerous commenters objected to our definition of coal cooperatives. These commenters argued that our definition and the application of our rules to coal cooperatives did not accurately reflect the corporate structure of cooperatives, would penalize small producers, and deviates from our intent to value coal at the mine.

ONRR Response: We seek a clear, consistent, and repeatable standard for valuing coal at its true market value. Coal cooperatives of varying forms (and complexity) are, primarily, designed for mutual economic advantage. We share the concerns that some commenters expressed that sales within coal cooperatives may not reflect the true market value of the coal. We require

lessees to value coal consistent with other commodities—at their first arm's-length sale between entities with competing economic interests, rather than common interests. We disagree with the comment that the definition of coal cooperatives is “unnecessary.” In fact, given the unique institutional nature of cooperatives in the coal industry—corporate relations among mine producers, logistics operations, electric generation, and overseas sales—that is not commonly found in markets for oil and gas, we deemed it imperative to define coal cooperatives for royalty purposes.

Valuing coal based on sales of electricity: In some situations, the lessees do not sell coal but, rather, transfer the coal along a series of non-arm's-length transactions to an affiliated generator of coal-fired electricity, who then sells electricity generated from the coal. We require lessees to base the value of the coal on the value of electricity sold, less applicable deductions for transmission, generation, coal washing, and transportation.

Public Comment: We received numerous comments, both supporting and opposing, using the value of electricity to value coal in cases of no sales or sales within coal cooperatives. Supporters argued that, in cases of no sales or non-arm's-length sales across coal cooperatives, assessing the value of coal as that of the generated electricity gives the most accurate representation of the coal's value. Some of these commenters argued that coal should be valued at the last arm's-length sale of electricity. Opponents argued that valuing coal using electric sales was a violation of the MLA, ignored and oversimplified the complexities of electric markets and contracts, and was administratively burdensome. In addition, they argued that ONRR's reference to geothermal regulations for valuing electricity was outside the scope of coal valuation.

ONRR Response: We disagree with comments asserting that using electric sales to value Federal coal, for royalty purposes, is inconsistent with the MLA. Rather, the MLA expressly provides the Secretary's discretion to determine value: “A lease shall require payment of a royalty in such amount as the Secretary shall determine of not less than 12½ per centum of the value of coal as defined by regulation.” 30 U.S.C. 207. This rule simply defines the value of coal.

As previously stated, based on our experience, arm's-length sales are the best indicator of value. Due to the complexity of affiliated interests across coal mining, logistics, and sales that

many commenters referenced, the first arm's-length sale could easily be the sale of generated electricity. According to the EIA, in 2014, over 93 percent of coal consumption was used in electric generation nationally.

We require lessees to value coal based on the first arm's-length sale, regardless if that sale is for coal or electricity. However, the rule does allow lessees to deduct costs associated with converting the coal to electricity to arrive at the value of the coal at the lease—not the value of the electricity. We will only use sales of electricity to value coal in situations where the first arm's-length sale is the sale of electric power along a series of no sales or non-arm's-length sales.

2. Determination of Correct Royalty Payments (§ 1206.253)

Default: We added a default valuation provision in § 1206.253 under which we can value a lessee's Federal coal if we decide to do so using the criteria in § 1206.254 or any other provision in these subparts.

Public Comment: Almost unanimously, industry commenters and others who support industry's position objected to the use of ONRR's proposed default provision for coal. Several industry commenters argued against ONRR's ability to determine royalty value when coal is sold for 10 percent less than the lowest reasonable measures of market value. Commenters stated that some companies can negotiate better prices than others based on size and bargaining power.

Several industry trade associations stated that, under its default provision, ONRR could upend reasonable and settled expectations whenever we decide for any reason that it dislikes any given lessee's reported coal valuation. These industry commenters also believe (1) that this provision does not allow ONRR to honor arm's-length contracts and gross proceeds as the basis of valuation as in the past; (2) there is a lack of specific criteria for determining what is reasonable valuation; (3) the default provision should not be used for simple reporting errors; and (4) the default provision is burdensome, an overreach of valuation authority, and creates uncertainty.

Several public interest groups suggested that the default provision should be mandatory and not discretionary. They supported ONRR's proposal to establish a default valuation mechanism, which provides the agency with needed authority to ascertain the value of Federal and Indian coal where the government otherwise would fail to garner a fair return on its resource as the

result of a lessee's misconduct. The commenters believe that the sources of information upon which ONRR proposes to base its determination of the coal's value are appropriate and, to the extent that they include publicly accessible information, would promote transparency. The comments from public interest groups stated that, when industry fails to abide by the terms of its commitment to market Federal coal for the mutual benefit of the lessee and the Federal government, thereby depriving the government of royalties on the full market value of its coal, the regulations should eliminate the lessee's privilege to continue to determine its own coal value and royalty payments. A comment from a public interest group stated that hesitancy of invoking this default proposition guts the method's efficacy and limits the extent to which the rule will close the first arm's-length sale loophole.

ONRR Response: We disagree with the commenters' statements that the default provision is a radical departure from our historical valuation policy. The regulatory changes do not alter the underlying principles of the current regulations. For example, nothing in this final rule changes the Department's requirement that, for the purposes of determining royalty, the value of coal produced from Federal leases is determined at or near the lease. And nothing in this final rule modifies or alters the fact that gross proceeds from arm's-length contracts are the best indication of market value.

The default provision addresses valuation situations where circumstances result in the Secretary's inability to reasonably determine the correct value of production. Such circumstances include, but are not limited to, (1) the lessee's failure to provide documents; (2) the lessee's misconduct; (3) the lessee's breach of the duty to market; or (4) any other situation that significantly compromises the Secretary's ability to reasonably determine the correct value. The mineral statutes and lease terms give the Secretary the authority and considerable discretion to establish the reasonable value of production by using a variety of discretionary factors and any other information that the Secretary determines is relevant. The default provision simply codifies the Secretary's authority to determine the value of production for royalty purposes and specifically enumerates when, where, and how the Secretary will use that discretion.

Under this new rule, we will not second-guess arm's-length contracts to any greater or lesser degree than we

have historically. We have never tacitly accepted values received under arm's-length contracts. We analyze all types of sales contracts in our reviews to validate proper value and deductions.

The criteria that we will use to establish a royalty value under the default provision is the same basic criteria that we base all royalty values upon. Further, we specifically list these criteria in the coal regulations. Factors that we could consider if we decide that we will determine value for royalty purposes under the default provision are clearly delineated and may include, but would not be limited to, (1) the value of like-quality coal from the same mine, nearby mines, same region, or other regions, or washed in the same or nearby wash plant; (2) public sources of price or market information that we deem reliable, including but not limited to, the price of electricity; (3) information available to us and information reported to us, including but not limited to, on the Solid Minerals Production and Royalty Report (Form ONRR-4430); (4) costs of transportation or washing, if we determine that they are applicable; or (5) any other information that we deem relevant regarding the particular lease operation or the salability of the coal.

3. Determination of Coal Value for Royalty Purposes (§ 1206.254)

Default: ONRR added a default valuation provision allowing us to value your coal under this section or any other provision in this subpart F. We address comments pertaining to the default provision, which we detail in § 1206.253, in this Preamble.

4. Valuation Determination Requests (§ 1206.258)

Guidance and Determinations: ONRR clarified how a lessee may request a valuation determination from us. We addressed comments pertaining to guidance and determinations in § 1206.108 of this Preamble. For the reasons that we discussed in response to comments, we deleted the words "or guidance" from the title and paragraph (a) of this section.

5. General Transportation Allowance Requirements (§ 1206.260)

This section contains the requirements of the previous § 1206.261. This section also consolidates provisions applicable to both arm's-length and non-arm's-length transportation in the previous regulations and clarifies that you do not need our approval to report a transportation allowance for arm's-length or non-arm's-length

transportation costs that you incur. Paragraph (c) explains in which circumstances you cannot take an allowance. Finally, we added paragraph (g), containing the default provision, which includes the requirements of previous paragraphs 1206.262(a)(2) and 1206.262(a)(3) regarding additional consideration, misconduct, and breach of the duty to market.

Fifty-percent allowance cap: In the preamble of the proposed rule, we solicited comments on whether or not we should impose a 50-percent cap on coal transportation allowances.

Public Comment: ONRR received several comments from public interest groups, the public, and one individual commenter maintaining that ONRR should cap or eliminate transportation allowances. Commenters supporting a 50-percent cap on transportation suggested that coal transportation allowances should be in line with the oil and gas transportation regulations. Several commenters suggested that ONRR should use an index or a published common carrier rate to establish the cost of transportation.

Local businesses, companies, and industry trade groups opposed any type of cap on transportation allowances, stating that the costs of transporting coal are significant and the corresponding deductions are critical to maintain economic operations. Companies and industry trade groups argued that transportation allowances were the best way to establish the value of coal at the mine where the lessee sells coal in a distant market. Further, industry trade groups opposed using standard schedules for transportation allowances, stating that transporting coal is subject to unpredictable market variables and that ONRR should use actual costs.

ONRR Response: After careful review of the comments, we will not impose a cap on transportation allowances at this time. We consider the reasonable, actual cost of transporting coal to be the best method for establishing an appropriate allowance when determining coal royalty value and will continue to implement this regulation.

Written contracts: ONRR added a new provision stating that we will determine transportation allowances if lessees do not have a written contract for the arm's-length transportation of coal. We addressed comments pertaining to this issue, which we discussed in § 1206.104, in this Preamble.

Default provision: ONRR added a default provision under which we may determine your transportation allowance under § 1206.254 if (1) there is misconduct by or between the contracting parties, (2) the total

consideration the lessee or its affiliate pays under an arm's-length contract does not reflect the reasonable cost of transportation or because the lessee breached its duty to market coal for the mutual benefit of the lessee and the lessor by transporting coal at a cost that is unreasonably high, or (3) ONRR cannot determine if the lessee properly calculated a transportation allowance for any reason.

Public Comment: Many of the comments from industry and industry trade groups regarding ONRR's potential use of the default provision, as it relates to the transportation of coal, are similar to those put forth for determining the allowances for oil or gas. Commenters believe that ONRR's use of a 10-percent variance above the highest reasonable measure of transportation standard is arbitrary, capricious, and unnecessary. Some commenters representing States' interests, however, believe that ONRR should include stronger regulatory language that requires ONRR to use the default method when the 10-percent variance is reached.

ONRR Response: Please refer to our response to § 1206.253 for a more detailed explanation of the default provision. The default provision is a well-conceived valuation tool that the Secretary will use to determine the correct amount of transportation deductions for coal. The 10-percent variance that we *may* use in our analysis of transportation transactions is nothing more than a tolerance to help determine a proper transportation allowance. In past and current compliance reviews and audit procedures, we have always used tolerances to reflect what is reasonable in any given market, at any given time. Our use of the default provision under the final valuation regulations is a continuation of current practice. We will continue to determine transportation costs that industry incurs on their own merits based on reasonable actual costs allowable under the regulations.

Misconduct: ONRR added a new definition for the term "*misconduct*." We addressed comments pertaining to this issue, which we detail in § 1206.20, in this Preamble.

6. Determining Non-Arm's-Length Transportation (§ 1206.262)

ONRR intended for the paragraphs addressing the BBB bond rate to be the same as those in the oil and gas provisions. Therefore, we deleted paragraph (k)(3).

7. General Washing Allowance Requirements (§ 1206.267)

ONRR added this section to contain the requirements of previous § 1206.258. We clarified that you do not need prior approval for reporting an allowance for the costs to wash coal and you must allocate washing costs attributable to each Federal lease. We also added that you cannot take an allowance for washing lease production that is not royalty-bearing, can only claim the costs of washing as an allowance when you sell the washed coal, and added the same default provision as that for the Federal oil, gas, and coal transportation regulations discussed in §§ 1206.110(f), 1206.152(g), and 1206.260(g).

Fifty-percent washing allowance cap: In the preamble of the proposed rule, ONRR solicited comments on whether we should impose a 50-percent cap on washing allowances.

Public Comment: ONRR received several comments from public interest groups, the general public, and a State maintaining that ONRR should not allow any deductions for the costs of washing coal because they are costs to place the coal in to marketable condition. Some of those same commenters, however, stated that, if ONRR continues to allow the costs of washing coal, they support a 50-percent cap on those allowances. Some commenters suggested that an ONRR-created index should be developed to determine washing allowances, while others similarly stated that, if ONRR does allow the washing allowances, the allowances should be fixed in advance.

An industry trade group opposed any cap on washing allowances, stating that the costs of washing coal are significant and the corresponding deductions are critical to maintain economic operations. It also stated that the costs of washing coal must be deductible from gross proceeds in order to maintain royalty on the value of coal at the lease rather than on an inflated basis.

ONRR Response: After careful review of the comments, we will not impose a cap on washing allowances at this time and will continue the practice of allowing the deduction of the costs of washing coal. The reasonable, actual cost of coal washing is the preferred method to arrive at an appropriate allowance when determining coal royalty value, and we will continue to implement this regulation.

Written contracts: ONRR added a new provision stating that we will determine washing allowances if lessees do not have a written contract for the arm's-length washing of coal. We addressed comments pertaining to this issue,

which we detail in § 1206.104, in this Preamble.

Default provision: ONRR added a default provision under which we may determine your washing allowance under § 1206.254 if (1) there is misconduct by or between the contracting parties; (2) the total consideration that the lessee or its affiliate pays under an arm's-length contract does not reflect the reasonable cost of washing or because the lessee breached its duty to market coal for the mutual benefit of the lessee and the lessor by washing coal at a cost that is unreasonably high; or (3) we cannot determine if the lessee properly calculated a washing allowance for any reason.

Public Comment: Many of the comments from industry and industry trade associations regarding ONRR's potential use of the default provision, as it relates to the washing of coal, are similar to those put forth for determining the allowances for oil or gas. Commenters believe that ONRR's use of a 10-percent variance above the highest reasonable measure of washing standard is arbitrary, capricious, and unnecessary. Some commenters representing States' interests, however, believe that ONRR should include stronger regulatory language that requires ONRR to use the default method when the 10-percent variance is reached.

ONRR Response: We provide a detailed response to the default provision topic in this Preamble under § 1206.253. The default provision is a well-conceived valuation tool that the Secretary will use to determine the correct amount of washing deductions for coal. The 10-percent variance that we may use in our analysis of washing transactions is nothing more than a tolerance to help determine a proper washing allowance. In past and current compliance reviews and audit procedures, we have always used tolerances to reflect what is reasonable in any given market, at any given time. Our use of the default provision under the final valuation regulations is a continuation of current practice. We will continue to determine washing costs that industry incurs on their own merits based on reasonable, actual costs allowable under the regulations.

8. Determining Non-Arm's-Length Washing (§ 1206.269)

ONRR intended for the paragraphs addressing the BBB bond rate to be the same as those in the oil and gas provisions. Therefore, we deleted paragraph (k)(3).

E. Specific Comments on 30 CFR Part 1206—Product Valuation, Subpart J—Indian Coal

1. Purpose and Scope (§ 1206.450)

ONRR replaced the term “Indian allottee” with “individual Indian mineral owner.” We made no other substantive changes to this section.

Public Comment: A Tribe proposed adding language that clarifies that an operating agreement between the lessor and lessee is also considered a lease.

ONRR Response: We clearly defined the term “lease” in § 1206.20 and find it unnecessary to add additional language here.

2. Valuation Determination Requests (§ 1206.458)

Guidance and Determinations: Under paragraph (a), a lessee may request a valuation determination or guidance from ONRR regarding any coal produced. Paragraph (a) provides that the lessee's request for a determination must (1) be in writing, (2) identify all leases involved, (3) identify all interest owners in the leases, (4) identify the operator(s) for those leases, and (5) explain all relevant facts. In addition, under paragraph (a), a lessee must provide (1) all relevant documents, (2) its analysis of the issue(s), (3) citations to all relevant precedents (including adverse precedents), and (4) its proposed valuation method.

In response to a lessee's request for a determination, we may (1) decide that we will issue guidance, (2) inform the lessee in writing that we will not provide a determination or guidance, or (3) request that the ASPMB issue a determination.

Paragraphs (b)(3)(i) and (ii) identify situations in which ONRR and the Assistant Secretary typically do not provide a determination or guidance, including, but not limited to, requests for guidance on hypothetical situations and matters that are the subject of pending litigation or administrative appeals.

Under paragraph (c)(1), a determination that ASPMB signs binds both the lessee and ONRR unless the Assistant Secretary modifies or rescinds the determination.

Public Comment: A Tribe proposed adding language to paragraph (b)(1) stating that ONRR will consult with the Indian Tribe prior to issuing a decision.

ONRR Response: We routinely consult with Tribes and find it unnecessary to add language to this paragraph.

We addressed additional comments pertaining to guidance and determinations in § 1206.108. For the

reasons discussed in response to comments, we deleted the words, “or guidance” from the title and paragraph (a) of this section.

3. Determination of Non-Arm’s-Length Transportation (§ 1206.462)

ONRR intended for the paragraphs addressing the BBB bond rate to be the same as those in the oil and gas

provisions. Therefore, we deleted paragraph (k)(3).

4. Determination of Arm’s-Length Washing (§ 1206.467)

Default: ONRR addressed comments pertaining to the default provision for Federal coal, which we discuss in § 1206.267, in this Preamble.

5. Determination of Non-Arm’s-Length Washing (§ 1206.469)

ONRR intended for the paragraphs addressing the BBB bond rate to be the same as those in the oil and gas provisions. Therefore, we deleted paragraph (k)(3).

DERIVATION TABLE FOR PART 1206

The requirements of section:	Are derived from section:
Subpart C	
1206.20	1206.101; 1206.151; 1206.251; 1206.451.
1206.101	1206.102.
1206.102	1206.103.
1206.103	1206.104.
1206.106	1206.105.
1206.107	1206.106.
1206.108	1206.107.
1206.109	1206.108.
1206.110	1206.109.
1206.111	1206.110.
1206.112	1206.111.
1206.113	1206.112.
1206.114	1206.113.
1206.115	1206.114.
1206.116	1206.115.
1206.117	1206.116.
1206.118	1206.117.
Subpart D	
1206.140	1206.150.
1206.141(a)(1)–(3)	1206.152(a)(1).
1206.141(b)(1)–(3)	1206.152(a)(2).
1206.141(b)(4)	1206.152(b)(1)(iv).
1206.142(a)(4)	1206.153(a)(1).
1206.142(b)	1206.153(a)(2).
1206.142(c)	1206.153(b)(1)(i).
1206.143(a)(1) and (b)	1206.152(b)(1)(ii); 1206.153(b)(1)(ii).
1206.143(a)(2)	1206.152(f); 1206.153(f).
1206.143(c)	1206.152(b)(1)(iii); 1206.153(b)(1)(iii).
1206.144	1206.152(c)(1)–(3); 1206.153(c)(1)–(3).
1206.145	1206.152(e)(1) and (2); 1206.153(e)(1) and (2); 1206.157(c)(1)(ii) and (c)(2)(iii); 1206.159(c)(1)(ii) and (c)(2)(iii).
1206.146	1206.152(i); 1206.153(i).
1206.147	1206.152(k); 1206.153(k).
1206.148	1206.152(g); 1206.153(g).
1206.149	1206.152(l); 1206.153(l).
1206.150	1206.154.
1206.151	1206.155.
1206.152(a)	1206.156(a).
1206.152(b)	1206.156(b); 1206.157(a)(2) and (b)(3).
1206.152(c)(1)	1206.157(a)(2) and (b)(4).
1206.152(f)	1206.157(a)(4).
1206.153(b)	1206.157(f).
1206.153(c)	1206.157(g).
1206.154(a)	1206.157(b).
1206.154(e)–(h)	1206.157(b)(2)(i)–(iii).
1206.154(i)	1206.157(b)(2)(iv).
1206.154(i)(3)	1206.157(b)(2)(v).
1206.155	1206.157(c)(1)(i), (ii).
1206.156	1206.157(c)(2)(i)–(iv).
1206.157(a)(1) and (c)	1206.156(d).
1206.157(a)(2) and 1206.158	1206.157(e).
1206.159(a)(1)	1206.158(a).
1206.159(b)	1206.158(b).
1206.159(c)(1) and (2)	1206.158(c)(1) and (2).
1206.159(d)	1206.158(d)(1).
1206.160	1206.159(a).
1206.161	1206.159(b).

DERIVATION TABLE FOR PART 1206—Continued

The requirements of section:	Are derived from section:
1206.162	1206.159(c)(1).
1206.163	1206.159(c)(2).
1206.164	1206.159(d).
1206.165	1206.159(e).
Subpart F	
1206.250	1206.250.
1206.251	1206.254; 1206.255; 1206.260.
1206.252(d)	1206.258(a); 1206.261(b).
1206.260(a)(1) and (b)	1206.261(a).
1206.260(c)(2)	1206.261(a)(2).
1206.260(d)	1206.261(c)(3).
1206.260(e)	1206.261(c)(1), (c)(2), and (e).
1206.260(f)	1206.262(a)(4).
1206.260(g)	1206.262(a)(2) and (a)(3).
1206.261	1206.262(a)(1).
1206.262	1206.262(b).
1206.263	1206.262(c)(1).
1206.264	1206.262(c)(2).
1206.265	1206.262(d).
1206.266	1206.262(e).
1206.267(a)	1206.258(a).
1206.267(b)(2)	1206.258(c); 1206.260.
1206.267(c)	1206.259(a)(4).
1206.267(d)	1206.259(a)(2) and (a)(3).
1206.267(e)	1206.258(e).
1206.268	1206.259(a)(1).
1206.269	1206.259(b).
1206.270	1206.259(c)(1).
1206.271	1206.259(c)(2).
1206.272	1206.259(d).
1206.273	1206.259(e).
Subpart J	
1206.450	1206.450.
1206.451	1206.453; 1206.454; 1206.459.
1206.460	1206.461(a)(1).
1206.463	1206.461(c).

III. Procedural Matters**1. Summary Cost and Royalty Impact Data**

We estimated the costs and benefits that this rule will have on all potentially affected groups: Industry, the Federal Government, Indian lessors, and State and local governments. These amendments that have cost impacts will result in an estimated annual increase in royalty collections. The sum of these amendments that have cost benefits are

due to administrative cost savings to industry, not a decrease in royalties due. The net impact of these amendments is an estimated annual increase in royalty collections of between \$71.9 million and \$84.9 million. This net impact represents a slight increase of between 0.8 percent and 1.0 percent of the total Federal oil, gas, and coal royalties that we collected in 2010. We also estimate that industry will experience reduced annual administrative costs of \$3.61 million.

Please note that, unless otherwise indicated, numbers in the following tables are rounded to three significant digits.

A. Industry

The table below lists ONRR's low, mid-range, and high estimates of the costs, by component, that industry will incur in the first year. Industry will incur these costs in the same amount each year thereafter.

SUMMARY OF ROYALTY IMPACTS TO INDUSTRY

Rule provision	Low	Mid	High
Gas—to replace benchmarks			
Affiliate resale	\$0	\$2,010,000	\$4,030,000
Index	11,300,000	11,300,000	11,300,000
NGLs—to replace benchmarks			
Affiliate resale	0	256,000	510,000
Index	1,200,000	1,200,000	1,200,000
Gas transportation limited to 50%	4,170,000	4,170,000	4,170,000
Processing allowance limited to 66⅔%	5,440,000	5,440,000	5,440,000
POP contracts limited to 66⅔% processing allowance	0	0	0
Extraordinary processing allowance	18,500,000	18,500,000	18,500,000

SUMMARY OF ROYALTY IMPACTS TO INDUSTRY—Continued

Rule provision	Low	Mid	High
BBB bond rate change for gas transportation	1,640,000	1,640,000	1,640,000
Eliminate deep water gathering	17,400,000	20,500,000	23,600,000
Oil transportation limited to 50%	6,430,000	6,430,000	6,430,000
Oil and gas line losses	4,571,000	4,571,000	4,571,000
BBB bond rate change for oil transportation	2,380,000	2,380,000	2,380,000
Coal—to non-arm's-length netback & co-op sales	(1,060,000)	0	1,060,000
Total	71,922,000	78,390,000	84,850,000

Note 1: Totals from this table and others in this analysis may not add due to rounding.

Note 2: Lessees may experience a one-time administrative cost to update their systems to comply with this rule. However, because a change would be unique to an individual lessee, ONRR was unable to quantify those one-time costs. Recognizing lessees may have to change their systems, we set the effective date of this rule to 180 days from the date of publication.

ONRR identified two rule changes that will benefit industry by reducing their administrative costs. The benefits that industry will realize for each of these components are as follows:

Rule provision	Benefit
Replace benchmarks— Gas & NGLs	\$247,000
Eliminate deep water gathering	3,360,000
Total	3,610,000

The table below lists the overall economic impact to industry from the rule changes, based on the mid-range estimate of costs:

Description	Annual (cost)/benefit amount
Cost—All rule provisions	(\$78,390,000)
Benefit—Administrative savings	3,610,000
Net cost or benefit to industry	(74,780,000)

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

As discussed above, we will replace the current benchmarks in

§§ 1206.152(c) (unprocessed gas) and 1206.152(c) (processed gas) with a methodology that uses the gross proceeds under the lessee's affiliate's first arm's-length sale to value gas for royalty purposes. The lessee also will have the option to elect to pay royalties based on a value using the monthly high index price, less a standard deduction for transportation.

To perform this economic analysis, we first extracted royalty data that we collected on residue gas, unprocessed gas, and coalbed methane (product codes 03, 04, 39, respectively) for calendar year 2010. We chose calendar year 2010 because the Royalty-in-Kind (RIK) volumes were minimal due to the 2010 termination of the RIK program. In previous years, RIK volumes were substantial. Data from RIK production is not representative of industry sales, so we excluded any remaining RIK volumes from our analysis.

We then extracted gas royalty data for non-arm's-length transactions reported with a sales type code of NARM. We also extracted gas royalty data for sales type code POOL because royalty reporters may also use this code to report non-arm's-length transactions. Based on our experience with auditing transactions that use sales type code

POOL, we know that only a relatively small portion of them are non-arm's-length. Therefore, we used only 10 percent of the POOL volumes in our economic analysis of the volumes of gas sold non-arm's-length.

Based on our experience auditing production sold under non-arm's-length contracts, we find that industry will incur a royalty increase in the range of 0 to 5 cents per MMBtu under our proposal to use the affiliate's first arm's-length resale to value gas production for royalty purposes. We created a range of potential royalty increases by assuming no royalty increase for the low estimate, 2.5 cents per MMBtu for the mid-range estimate, and 5 cents per MMBtu for the high estimate. We then multiplied the NARM volume and 10 percent of the POOL volume reported to us in 2010 by the potential royalty increases.

The results that we provided below are an estimated cost to industry due to an annual royalty increase of between zero and approximately \$8 million. We reduced this estimate by one-half to \$4.03 million, assuming lessees whose volumes represent 50 percent of the non-arm's-length sales will choose this option.

	2010 MMBtu (non-rounded)	Royalty increase (\$)		
		Low (0 cents)	Mid (2.5 cents)	High (5 cents)
NAL volume	149,348,561	\$0	\$3,730,000	\$7,470,000
10% of POOL volume	11,606,523	0	290,000	580,000
Total	160,955,084	0	4,020,000	8,050,000
50% of non-arm's-length volumes		0	2,010,000	4,030,000

Cost—Using Index Price Option to Value Non-Arm's-Length Sales of Federal Unprocessed Gas, Residue Gas, and Coalbed Methane

To estimate the royalty impact of the index-based option, we calculated a monthly weighted average price net of transportation using NARM and 10 percent of the POOL gas royalty data from six major geographic areas with active index prices: The Green River Basin; San Juan Basin; Piceance and Uinta Basins; Powder River and Wind River Basins; Permian Basin; and Offshore Gulf of Mexico (GOM). These six areas account for approximately 95 percent of all Federal gas produced. To calculate the estimated impact, we performed the following steps:

(1) Identified the *Platts Inside FERC* highest reported monthly price for the index price applicable to each area—Northwest Pipeline Rockies for Green

River, El Paso San Juan for San Juan, Northwest Pipeline Rockies for Piceance and Uinta, Colorado Interstate Gas for Powder River and Wind River, El Paso Permian for Permian, and Henry Hub for GOM.

(2) Subtracted the transportation deduction that we specified in the proposed rule from the highest index price that we identified in step (1).

(3) Subtracted the average monthly net royalty price reported to us for unprocessed gas from the highest index price for the same month that we calculated in step (2).

(4) Multiplied the royalty volume by the monthly difference that we calculated in step (3) to calculate a monthly royalty difference for each region.

(5) Totaled the difference that we calculated in step (4) for the regions.

Although the index-based methodology resulted in an annual increase in royalties due, the current average royalty prices reported to us were higher than the index-based option for three months in 2010.

We estimate that the cost to industry due to this change will be an increase in royalty collections of approximately \$11.3 million annually. This estimate represents a small average increase of approximately 3.6 percent or 14 cents per MMBtu, based on an annual royalty volume of 160,955,084 MMBtu (for NARM and 10 percent POOL reported sales type codes). Because this is the first time that we have offered this option, we don't know how many payors will choose it. We reduced this estimate by one-half, assuming lessees whose volumes represent 50 percent of the non-arm's-length sales will choose this option.

2010 Index analysis	GOM gas	Other gas	Total
Current royalties (rounded to the nearest dollar)	\$167,291,148	\$435,222,354	\$602,513,502
Royalty under index option	180,000,000	445,000,000	625,000,000
Difference	12,700,000	9,780,000	22,500,000
Per unit uplift (\$/MMBtu)	0.297	0.083	0.140
% change	7.06	2.20	3.60
50% of non-arm's-length volumes			11,300,000

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal NGLs

Like the valuation changes that we discussed above, for Federal unprocessed, residue, and coalbed methane gas valuation changes, this rule will value processed Federal NGLs based on the first arm's-length sale rather than the current benchmarks. The lessee also will have the option to pay royalties using an index-price value derived from an NGL commercial price

bulletin, less a theoretical processing allowance that includes transportation and fractionation of the NGLs. We again used the 2010 NARM and POOL NGL data reported to us for this analysis.

We performed the same analysis for valuation using the first arm's-length sale for Federal unprocessed, residue, and coalbed methane gas, as we discussed above. We identified the non-arm's-length volumes that would qualify for this option (for NARM and 10 percent POOL reported sales type codes) and estimated a cents-per-gallon royalty

increase. Based on our experience, the NGLs resale margin is, similar to gas, relatively small, ranging from zero to 3 cents per gallon. Thus, our estimated royalty increase is zero for the low, 1.5 cents per gallon for the mid-range, and 3 cents per gallon for the high range. The results provided below show a mid-range royalty increase of \$256,000 using these assumptions, and, again, we reduced them by one-half, assuming lessees whose volumes represent 50 percent of the non-arm's-length sales will choose this option.

	2010 Gallons (rounded to the nearest gallon)	Royalty increase (\$)		
		Low (0 cents)	Mid (1.5 cents)	High (3 cents)
NAL volume	6,170,341	\$0	\$92,600	\$185,000
10% of POOL volume	27,913,486	0	419,000	837,000
Total	34,083,827	0	512,000	1,020,000
50% of non-arm's-length volumes		0	256,000	510,000

Cost—Using Index Price Option to Value Non-Arm's-Length Sales of Federal NGLs

Like the Federal unprocessed, residue, and coalbed methane gas changes that we discussed above,

lessees also will have the option to pay royalties on Federal NGLs using an index-based value less a theoretical processing allowance that includes transportation and fractionation. We used the same 2010 NARM and POOL

transaction data for NGLs for this analysis. We were unable to compare NGLs prices reported on Form ONRR-2014 to those in commercial price bulletins because prices that lessees report on Form ONRR-2014 are one

rolled-up price for all NGLs. Conversely, the bulletins price each NGL product (such as ethane and propane) separately. We based our analysis on the royalty changes that will result from the theoretical processing allowance proscribed under this new option.

We chose a conservative number as a proxy for the processing allowance deduction that we will allow for this index option. To determine the cost of this option for NGLs, we calculated the difference between the average processing allowance reported on Form ONRR–2014 and the proxy allowance that we will allow under this option. That difference equaled an increase in value of approximately 7 cents per gallon. We then multiplied the total NAL volume of 34,083,827 gallons reported to us by the 7 cents per gallon, for an estimated royalty increase of \$2.4 million. We reduced this number by

one-half under the assumption that 50 percent of lessees will choose this option, resulting in a total cost to industry of \$1.2 million.

Benefit—Using Index Price Option to Value Non-Arm’s-Length Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs

We expect that industry will benefit by realizing administrative savings if they choose to use the index-based option to value non-arm’s-length sales of Federal unprocessed gas, residue gas, coalbed methane, and NGLs. Lessees will know the price to use to value their production, saving the time that it currently takes to calculate the correct price based on the current benchmarks. They also will save time using the ONRR-specified transportation rate for gas and the ONRR-specified processing

allowance for NGLs, rather than having to calculate those values themselves.

Of the lessees that we estimated will use this option, we estimated the index-based option will shorten the time burden per line reported by 50 percent to 1.5 minutes for lines that industry electronically submits and 3.5 minutes for lines that they manually submit. We used tables from the Bureau of Labor Statistics (BLS) (www.bls.gov/oes132011.htm) to estimate the hourly cost for industry accountants in a metropolitan area. We added a multiplier of 1.4 for industry benefits. The industry labor cost factor for accountants will be approximately \$50.53 per hour = \$36.09 [mean hourly wage] × 1.4 [benefits cost factor]. Using a labor cost factor of \$50.53 per hour, we estimate the annual administrative benefit to industry will be approximately \$247,000.

	Time burden per line reported	Estimated lines reported using index option (50%)	Annual burden hours
Electronic reporting (99%)	1.5 min	190,872	4,772
Manual reporting (1%)	3.5 min	1,928	112
Industry labor cost/hour			\$50.53
Total benefit to industry			\$247,000

Cost—Elimination of Transportation Allowances in Excess of 50 Percent of the Value of Federal Gas

The previous Federal gas valuation regulations limited lessees’ transportation allowances to 50 percent of the value of the gas unless they requested and received approval to exceed that limit. This rule eliminated the lessees’ ability to exceed that limit. To estimate the costs associated with this change, we first identified all calendar year 2010 reported gas transportation allowances rates that exceeded the 50-percent limit. We then adjusted those allowances down to the 50-percent limit and totaled that value to estimate the economic impact of this provision. The result was an annual estimated cost to industry of \$4.17 million in additional royalties.

Cost—Elimination of Transportation Allowances in Excess of 50 Percent of the Value of Federal Oil

The previous Federal oil valuation regulations limit lessees’ transportation allowances to 50 percent of the value of the oil unless they request and receive approval to exceed that limit. This rule eliminates the lessees’ ability to exceed

that limit. To estimate the costs associated with this change, we first identified all calendar year 2010 reported oil transportation allowance rates that exceeded the 50-percent limit. We then adjusted those allowances down to the 50-percent limit and totaled that value to estimate the economic impact of this provision. The result was an annual estimated cost to industry of \$6.43 million in additional royalties.

Cost—Elimination of Processing Allowances in Excess of 66⅔ Percent of the Value of the NGLs for Federal Gas

The previous Federal gas valuation regulations limit lessees’ processing allowances to 66⅔ percent of the value of the NGLs unless they request and receive approval to exceed that limit. This rule eliminates the lessees’ ability to exceed that limit. To estimate the cost to industry associated with this change, we first identified all calendar year 2010 reported processing allowances greater than 66⅔ percent. We then adjusted those allowances down to the 66⅔-percent limit and totaled that value to estimate the economic impact of this provision. The result was an annual estimated cost to industry of \$5.44 million in additional royalties.

Cost—POP Contracts now Subject to the 66⅔-percent Processing Allowance Limit for Federal Gas

Lessees with POP contracts currently pay royalties based on their gross proceeds as long as they pay a minimum value equal to 100 percent of the residue gas. Under this rule, we also will not allow lessees with POP contracts to deduct more than the 66⅔ percent of the value of the NGLs. For example, a lessee with a 70-percent POP contract receives 70 percent of the value of the residue gas and 70 percent of the value of the NGLs. The 30 percent of each product that the lessee gives up to the processing plant in the past cannot, when combined, exceed an equivalent value of 100 percent of the NGLs’ value. Under this rule, the combined value of each product that the lessee gives up to the processing plant cannot exceed two-thirds of the NGLs’ value.

Lessees report POP contracts to ONRR using sales type code APOP for arm’s-length POP contracts and NPOP for non-arm’s-length POP contracts. Because lessees report APOP sales as unprocessed gas, there are no reported processing allowances for us to analyze, and we cannot determine the breakout

between residue gas and NGLs. Lessees do report residue gas and NGLs separately for NPOPs. However, NPOP volumes constitute only 0.02 percent of all of the natural gas royalty volumes that lessees report to us. We deemed the NPOP volume to be too low to adequately assess the impact of this provision on both APOP and NPOP contracts.

Therefore, we decided to examine all reported calendar year 2010 onshore

residue gas and NGLs royalty data and assumed that it was processed and that lessees paid royalties as if they sold the residue gas and NGLs under a POP contract. We restricted our analysis to residue gas and NGLs volumes produced onshore because we are not aware of any offshore POP contracts. We first totaled the residue gas and NGLs' royalty value for calendar year 2010 for all onshore royalties. We then assumed that these royalties were subject to a 70-

percent POP contract. Based on our experience, a 70/30 split is typical for POP contracts. We calculated 30 percent of both the value of residue gas and NGLs to approximate a theoretical 30-percent processing deduction. We then compared the 30-percent total of residue gas and NGL values to 66⅔ percent of the NGL's value (the maximum allowance under this rule). The table below summarizes these calculations, which we rounded to the nearest dollar:

	2010 Royalty value	70%	30%
Residue gas	\$602,194,031	\$421,535,822	\$180,658,209
NGLs	506,818,440	354,772,908	152,045,532
Total	1,109,012,471	776,308,730	332,703,741
66.67% Limit	337,878,960	(506,818,440 × ⅔)

Our analysis shows that the theoretical processing deduction for 30 percent of the value of residue gas and NGLs (\$333 million) under our assumed onshore POP contract allowance will not exceed the 66⅔-percent cap (\$338 million) under this rule and, thus, we estimate that this change will be revenue-neutral.

Cost—Termination of Policy Allowing Transportation Allowances for Deep Water Gathering Systems for Federal Oil and Gas

The Deep Water Policy that we discuss above allowed companies to deduct certain expenses for subsea gathering from their royalty payments, even though those costs do not meet our definition of transportation. This final rule rescinds and supersedes the Deep Water Policy, and lessees will pay royalties under these valuation regulations applicable to Federal oil and gas transportation allowances, prospectively. To analyze the cost impact to industry of rescinding this policy, we used data from BSEE's ArcGIS Technical Information Management System database to estimate that 113 subsea pipeline segments serving 108 leases currently qualify for an allowance under the policy. We assumed that all segments were the same—in other words, we did not take into account the size, length, or type of pipeline. We also considered only pipeline segments that were in active status and leases in producing status for our analysis. To determine a range (shown in the tables below as low,

mid, and high estimates) for the cost to industry, we estimated a 15-percent error rate in our identification of the 113 eligible pipeline segments, resulting in a range of 96 to 130 eligible pipeline segments.

Historical ONRR audit data is available for 13 subsea gathering segments serving 15 leases covering time periods from 1999 through 2010. We used these data to determine an average initial capital investment in pipeline segments. We used the initial capital investment amount to calculate depreciation and a return on undepreciated capital investment (also known as the Return on Investment or ROI) for the eligible pipeline segments. We calculated depreciation using a straight-line depreciation schedule based on a 20-year useful life of the pipeline. We calculated ROI using 1.0 times the average BBB Bond rate for January 2012, which was the most recent full month of data when we performed this analysis. We based the calculations for depreciation and ROI on the first year when a pipeline was in service.

From the same audit data, we calculated an average annual Operating and Maintenance (O&M) cost. We increased the O&M cost by 12 percent to account for overhead expenses. Based on experience and audit data, we assumed that 12 percent is a reasonable increase for overhead. We then decreased the total annual O&M cost per pipeline segment by 9 percent because an average of 9 percent of offshore wellhead oil and gas production is

water, which is not royalty bearing. Finally, we used an average royalty rate of 14 percent, which is the volume weighted average royalty rate for all non-Section 6 leases in the GOM. Based on these calculations, the average annual allowance per pipeline segment is approximately \$226,000. This represents the estimated amount per pipeline segment that we will no longer allow a lessee to take as a transportation allowance based on our rescission of the Deep Water Policy in this rule.

The total cost to industry will be the \$226,000 annual allowance per pipeline segment that we will disallow under this rule times the number of eligible segments. To calculate a range for the total cost, we multiplied the average annual allowance by the low (96), mid (113), and high (130) number of eligible segments. The low, mid, and high annual allowance estimates that we will disallow are \$21.8 million, \$25.6 million, and \$29.5 million, respectively.

Of currently eligible leases, 42 out of 108, or about 40 percent, qualify for deep water royalty relief. However, due to varying lease terms, royalty relief programs, price thresholds, volume thresholds, and other factors, we estimated that only half of the 42 leases eligible for royalty relief (20 percent) actually received royalty relief. Therefore, we decreased the low, mid, and high estimated annual cost to industry by 20 percent. The table below shows the estimated royalty impact of this section of this rule based on the allowances that we will no longer allow under this rule.

	Low	Mid	High
Estimated royalty impact	\$17,400,000	\$20,500,000	\$23,600,000

Benefit—Termination of Policy Allowing Transportation Allowances for Deep Water Gathering Systems for Offshore Federal Oil and Gas

We estimate that the elimination of transportation allowances for deep water gathering systems will provide industry with an administrative benefit because they will no longer have to perform this calculation. The cost to

perform this calculation is significant because industry has often hired outside consultants to calculate their subsea transportation allowances. Using this information, we estimated that each company with leases eligible for transportation allowances for deep water gathering systems will allocate one full-time employee annually to perform this calculation if they use consultants or perform the calculation

in-house. We used the BLS to estimate the hourly cost for industry accountants in a metropolitan area [\$36.09 mean hourly wage] with a multiplier of 1.4 for industry benefits to equal approximately \$50.53 per hour [$\$36.09 \times 1.4 = \50.53]. Using this labor cost per hour, we estimate that the annual administrative benefit to industry will be approximately \$3,360,000.

	Annual burden hours per company	Industry labor cost/hour	Companies reporting eligible leases	Estimated benefit to industry
Deep water Gathering.	2,080	\$50.53	32	\$3,360,000

Cost—Elimination of Extraordinary Cost Gas Processing Allowances for Federal Gas

As we discussed above, we eliminated the provision in the previous regulations that allow a lessee to request an extraordinary processing cost allowance and to terminate any extraordinary cost processing allowances that we previously granted. We granted two such approvals in the past, so we know the lease universe that is claiming this allowance and were able to retrieve the processing allowance data that lessees deducted from the value of residue gas produced from the leases. We then calculated the annual total processing allowance that lessees have claimed for 2007 through 2010 for the leases at issue. We then averaged the yearly totals for those four years to estimate an annual cost to industry of \$18.5 million in increased royalties.

Cost—Decrease Rate of Return Used to Calculate Non-Arm's-Length Transportation Allowances From 1.3 to 1 Times the Standard and Poor's BBB Bond Rate for Federal Oil and Gas

For Federal oil transportation, we do not maintain or request data identifying if transportation allowances are arm's-length or non-arm's-length. However, based on our experience, a large portion of GOM oil is transported through lessee-owned pipelines. In addition, many onshore transportation allowances include costs of trucking and rail, and, most likely, this change will not impact those. Therefore, to calculate the costs associated with this change, we assumed that 50 percent of the GOM transportation allowances are non-arm's-length and 10 percent of

transportation allowances everywhere else (onshore and offshore other than the GOM) are non-arm's-length. We also assumed that, over the life of the pipeline, allowance rates are made up of one-third rate of return on undepreciated capital investment, one-third depreciation expenses, and one-third operation, maintenance, and overhead expenses. These are the same assumptions that we made when analyzing changes to both the Federal oil and Federal gas valuation rules in 2004.

In 2010, the total oil transportation allowances that Federal lessees deducted were approximately \$60 million from the GOM and \$11 million from everywhere else. Based on these totals and our assumptions about the allowance components, the portion of the non-arm's-length allowances attributable to the rate of return will be approximately \$10,000,000 for the GOM ($\$60,000,000 \times \frac{1}{3} \times 50\% = \$10,000,000$) and \$367,000 ($\$11,000,000 \times \frac{1}{3} \times 10\% = \$367,000$) for the rest of the country. Therefore, we estimate that decreasing the basis for the rate of return by 23 percent will result in decreased yearly oil transportation allowance deductions of approximately \$2,380,000 ($\$10,367,000 \times 0.23 = \$2,380,000$). Thus, we estimate that the net cost to industry as a result of this change will be an approximately \$2,380,000 increase in royalties due.

With respect to Federal gas, like oil, we do not maintain or request information on whether gas transportation allowances are arm's-length or non-arm's-length. However, unlike oil, it is not common for GOM gas to be transported through lessee-

owned pipelines. Therefore, we assumed that only 10 percent of all gas transportation allowances are non-arm's-length and made no distinction between the GOM and everywhere else. All other assumptions for natural gas are the same as those we made for oil above.

In 2010, the total gas transportation allowances that Federal lessees deducted were approximately \$214 million. Based on that total and our assumptions regarding the makeup of the allowance components, the portion of the non-arm's-length allowances attributable to the rate of return will be approximately \$7.13 million ($\$214,000,000 \times \frac{1}{3} \times 10\% = \$7,130,000$). Therefore, we estimate that decreasing the basis for the rate of return by 23 percent will result in decreased yearly gas transportation allowance deductions of approximately \$1.64 million ($\$7.13 \text{ million} \times 0.23$). That is, the net increased cost to industry, based on this change, will be approximately \$1,640,000 in additional royalties.

Cost—Allow a Rate of Return on Reasonable Salvage Value for Federal Oil, Gas, and Coal

For Federal oil and gas, after a transportation system or a processing plant has been depreciated to its reasonable salvage value, we will allow a lessee a return on that reasonable salvage value of the transportation system or processing plant as long as the lessee uses that system or plant for its Federal oil or gas production. We estimated that the economic impact on industry will be small because we will continue the requirements of the previous regulations that a lessee must base depreciation of a system or plant

upon the useful life of the equipment or the expected life of the reserves that the system or plant served. Thus, when properly established, the depreciation schedule should reflect the useful life of the system or plant, and we will not expect a lessee to continue to use a system or plant for periods significantly longer than the period reflected by the depreciation schedule that the lessee established for royalty purposes. This assumption is true, especially if the lessee did not make additional capital expenditures that extended the life of the system or plant. In that case, the lessee should have extended the depreciation schedule to reflect the extended life of the system or plant, and, possibly, the salvage value, itself. In other words, the vast majority of systems will not depreciate to salvage

value while royalty is being paid because the system still has a useful life while production occurs. Thus, there will not be any costs to industry associated with this change.

With respect to Federal coal, the royalty impact for coal will be equally small for the same reasons that we mentioned above.

Cost—Disallow Line Loss as a Component of Arm's-Length and Non-Arm's-Length Oil and Gas Transportation

We also will eliminate the current regulatory provision allowing a lessee to deduct costs of pipeline losses, both actual and theoretical, when calculating non-arm's-length transportation allowances. For this analysis, we assumed that pipeline losses are 0.2

percent of the volume transported through the pipeline, based on a survey of pipeline tariff. This 0.2 percent of the volume transported also equates to 0.2 percent of the value of the Federal royalty volume of oil and gas production transported.

For Federal oil produced in calendar year 2010, the total value of the Federal royalty volume subject to transportation allowances was \$3,796,827,823 in the GOM and \$1,204,177,633 everywhere else. Using our previous assumption that 50 percent of GOM and 10 percent of everywhere else's transportation allowances are non-arm's-length, we estimated that the value of the line loss will be \$4.04 million, as we detailed in the table below. Therefore, the annual cost to industry will be approximately \$4.04 million in additional royalties.

OIL LINE LOSS ROYALTY IMPACT

	Royalty value	Line loss (%)	Royalty increase
50% of GOM royalty value	\$1,898,413,912	0.2	\$3,800,000
10% of everywhere else royalty value	120,417,633	0.2	241,000
Total			4,040,000

For Federal gas produced in calendar year 2010, the royalty value of the Federal gas royalty volume subject to transportation allowances was

\$2,656,843,158. Using our previous assumption that 10 percent of Federal gas transportation allowances are non-arm's-length, we estimated that the

value of the line loss will be \$531,000. Therefore, the annual cost to industry will be approximately \$531,000 in increased royalties.

GAS LINE LOSS ROYALTY IMPACT

	Royalty value	Line loss (%)	Royalty increase
10% of royalty value	\$265,684,316	0.2	\$531,000

The total estimated royalty increase for both oil and gas due to this change will be \$4.57 million [\$4,040,000 (oil) + \$531,000 (gas) = \$4,571,000].

Cost—Depreciating Oil Pipeline Assets Only Once

We will allow depreciation of oil pipeline assets only one time. Under the previous valuation regulations for Federal oil, if an oil pipeline was sold, we allowed the purchasing company to include the purchase price to establish a new depreciation schedule and, in essence, depreciate the same piece of pipe twice or more if it was sold again. Under this final rule, we allow depreciation only once. In theory, this change can result in additional royalties. However, based on our experience monitoring the oil markets, we find that the sale of oil pipeline assets is rare, and we are not aware of

any such sales in the last five calendar years. We are also not aware of any planned future sales of oil pipelines that this rule change will impact. Therefore, although there will be a cost to industry under this rule, we cannot quantify the cost at this time.

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Federal Coal and Sales of Federal Coal Between Coal Cooperatives and Coal Cooperative Members and Between Coal Cooperative Members

We discuss this cost in the next section.

Cost—Using Sales of Electricity to Value Non-Arm's-Length Sales of Federal Coal and Sales of Federal Coal Between Coal Cooperatives and Coal Cooperative Members and Between Coal Cooperative Members

In our experience, non-arm's-length sales of Federal coal that is then resold

at arm's-length represent a small fraction of all coal sales. Under the previous valuation regulations, such sales result in royalty values equivalent to values that result under the regulation at § 1206.252(a) based on arm's-length resale prices. Thus, we estimated that there will be no royalty effect for these types of sales. In other words, there is no cost to lessees who produce Federal coal due to this valuation change in this rule.

The remaining non-arm's-length dispositions of Federal coal (including lessees, their affiliates, coal cooperatives, and members of coal cooperatives) are when the lessee, its affiliate, coal cooperatives, or members of coal cooperatives consume(s) the Federal coal produced to generate electricity. These dispositions typically constitute from about one to two percent

of royalties paid on Federal coal produced.

Under this rule, a lessee, its affiliates, a coal cooperative, and a member of a coal cooperative generally will base the royalty value of such sales on the sales value of the electricity, less costs to generate and, in some cases, transmit the electricity to the buyers, and less applicable coal washing and transportation costs. We have limited experience determining lease product royalty values using the method under § 1206.252(b)(1). Therefore, to perform an economic analysis, we first determined the average royalties paid to us in calendar years 2009 through 2011 for these Federal coal dispositions. Based on our experience with other dispositions of Federal coal, we estimated that, at most, royalty values under this rule will increase or decrease by 10 percent, compared to royalty values that we determined under previous regulations. Using these assumptions, we estimated the annual average royalty impact and, thus, the cost or benefit to industry from this rule.

Our method is the same for estimating the royalty impact of using sales of electricity to value non-arm's-length sales of Federal coal, sales of Federal coal between coal cooperatives and coal cooperative members, and sales between coal cooperative members. Therefore, the estimated royalty impact will be a combined figure covering all such valuation of Federal coal under this rule. Accordingly, we estimated that the combined average annual royalty impacts for these coal dispositions will range from a royalty decrease of \$1.06 million (benefit) to a royalty increase of \$1.06 million (cost).

Cost—Using Default Provision to Value Non-Arm's-Length Sales of Federal Coal in Lieu of Sales of Electricity

If we were unable to establish royalty values of Federal coal using the sales value of electricity generated from coal produced, royalty value will be based on a method that the lessee proposes under § 1206.252(b)(2)(i), which we approve, or on a method that we determine under § 1206.254. In either case, we will accept or assign a royalty value that will approximate the market value of the coal. Whether valuing under §§ 1206.252(b)(2)(i) or 1206.254, we and the lessee will employ a valuation method that uses or approximates market value. Current coal valuation regulations also attempt to provide royalty values that will approximate the market value of this coal. Thus, given the low percentage of non-arm's-length dispositions of Federal coal and the use of market-based

methods to determine royalty value under the current regulations and this rule, if valuation does not follow § 1206.252(a) or § 1206.252(b)(1), we estimate that the royalty effect of this rule on lessees of Federal coal will be nominal.

Cost—Using First Arm's-Length Sale to Value Non-Arm's-Length Sales of Indian Coal

Currently, Indian coal lessees sell their entire production at arm's-length, so this rule change will have no cost impact on them.

Cost—Using Sales of Electricity to Value Non-Arm's-Length Sales of Indian Coal

Currently, Indian coal lessees sell their entire production at arm's-length, so this rule change will have no cost impact on them.

Cost—Using First Arm's-Length Sale to Value Sales of Indian Coal Between Coal Cooperative Members

Currently, no coal cooperatives are Indian coal lessees, so we do not expect there to be any royalty impact as a result of this rule change.

Cost—Department Use of Default Provision to Value Federal Oil, Gas, or Coal and Indian Coal

As we discussed above, we added a default provision that addresses valuation when the Secretary cannot determine the value of production because of a variety of factors, or the Secretary determined that the value is wrong for a multitude of reasons (for example, misconduct). In those cases, the Secretary will exercise his/her authority and considerable discretion, to establish the reasonable value of production using a variety of discretionary factors and any other information that the Secretary deems appropriate. This default provision covers all products (Federal oil, gas, and coal and Indian coal) and all pertinent valuation factors (sales, transportation, processing, and washing).

Based on our experience, we anticipate that we will use the default provision only in specific cases where conventional valuation procedures have not worked to establish a value for royalty purposes. As such, we believe that assigning a royalty impact figure to any of the default provisions is speculative because (1) each instance will be case-specific, (2) we cannot anticipate when we will use the option, and (3) we cannot anticipate the value we will require companies to pay. Additionally, we estimated that the royalty impact will be relatively small

because the default provisions will always establish a reasonable value of production using market-based transaction data, which has always been the basis for our royalty valuation rules in the first instance.

B. State and Local Governments

This rule will not impose any additional burden on local governments. We estimate that the States, which this rule impacts, will receive an overall increase in royalties as follows:

States receiving revenues for offshore OCSLA Section 8(g) leases will share in a portion of the increased royalties resulting from this rule, as will States receiving revenues from onshore Federal lands. Based on the ratio of Federal revenues disbursed to States for section 8(g) leases and onshore States that we detail in the table below, we assumed the same proportion of revenue increases for each proposal that will impact those State revenues for most of the provisions.

ROYALTY DISTRIBUTIONS BY LEASE TYPE

	Onshore (%)	Offshore (%)	8(g) (%)
Federal	50	100	73
State	50	0	0
State (8g)	0	0	27

Some provisions, such as deep water gathering allowances, affect only Federal revenues, while others, such as the extraordinary processing allowance, affect only onshore States and Federal revenues. The table summarizing the State and local government royalty increases that we provide in section E details these differences.

The State distribution for offshore royalties will increase at some point in time because of the provisions of the Gulf of Mexico Energy Security Act of 2006 (GOMESA) (Pub. Law No. 109–432, 120 Stat. 2922). Section 105 of GOMESA provides OCS oil and gas revenue sharing provisions for the four Gulf producing States (Alabama, Louisiana, Mississippi, and Texas) and their eligible coastal political subdivisions. Through fiscal year 2016, the only shareable qualified revenues originate from leases issued within two small geographic areas. Beginning in fiscal year 2017, qualified revenues originating from leases issued since the passing of GOMESA located within the balance of the GOM acreage will also become shareable. The majority of these leases are not yet producing. The time necessary to start production operations and to produce royalty-bearing

quantities varies from lease to lease, and these factors directly influence how the distribution of offshore royalties will change over time. None of the leases in these frontier areas have begun producing, and it is speculative to anticipate when they will begin producing royalty-bearing quantities and impact the distribution of revenues to States.

C. Indian Lessors

We estimate that the rule changes to the coal regulations that apply to Indian lessors will have no impact on their royalties.

D. Federal Government

The impact to the Federal government, like the States, will be a net overall increase in royalties as a result of these rule changes. In fact, the royalty increase that the Federal government anticipates will be the difference between the total royalty increase from industry and the royalty increase affecting the States. The net yearly impact on the Federal government will be approximately 61.8 million that we detail in section E.

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

In the table below, the negative values in the Industry column represent increases in their estimated royalty burden, while the positive values in the other columns represent the increase in each affected group's royalty receipts. For the purposes of this summary table, we assumed that the average for royalty increases is the midpoint of our range.

Rule provision	Industry	Federal	State	State 8(g)
Gas—replace benchmarks				
Affiliate resale	(\$2,010,000)	\$1,390,000	\$605,000	\$13,500
Index	(11,300,000)	7,820,000	3,400,000	75,700
NGLs—replace benchmarks				
Affiliate resale	(256,000)	191,000	63,000	1,850
Index	(1,200,000)	896,000	295,000	8,650
Gas transportation limited to 50%	(4,170,000)	2,890,000	1,260,000	27,900
Processing allowance limited to 66⅔%	(5,440,000)	4,060,000	1,340,000	39,200
POP contracts limited to 66⅔%	0	0	0	0
Extraordinary processing allowance	(18,500,000)	9,250,000	9,250,000	0
BBB bond rate change for gas transportation	(1,640,000)	1,140,000	494,000	11,000
Eliminate deep water gathering	(20,500,000)	20,500,000	0	0
Oil transportation limited to 50%	(6,430,000)	5,810,000	594,000	27,100
Oil and gas line losses	(4,571,000)	4,130,000	422,000	19,200
BBB bond rate change for oil transportation	(2,380,000)	2,150,000	220,000	10,000
Coal—non-arm's-length netback & co-op sales	0	0	0	0
Total	(78,390,000)	60,260,000	17,942,000	234,000

2. Regulatory Planning and Review (Executive Orders 12866 and 13563)

Executive Order (E.O.) 12866 provides that the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget (OMB) will review all significant rulemaking. OIRA has determined that this rule is significant.

Executive Order 13563 reaffirms the principles of E.O. 12866, while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. This executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We developed this rule in a manner consistent with these requirements.

3. Regulatory Flexibility Act

The Department certifies that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), see item 1 above for the analysis.

This rule will affect lessees under Federal oil and gas leases and Federal and Indian coal leases. Federal and Indian mineral lessees are, generally, companies classified under the North American Industry Classification System (NAICS), as follows:

- Code 211111, which includes companies that extract crude petroleum and natural gas
- Code 212111, which includes companies that extract surface coal
- Code 212112, which includes companies that extract underground coal

For these NAICS code classifications, a small company is one with fewer than 500 employees. Approximately 1,920 different companies submit royalty and production reports from Federal oil and gas leases and Federal and Indian coal leases to us each month. Of these, approximately 65 companies are large businesses under the U.S. Small

Business Administration definition because they have more than 500 employees. The Department estimates that the remaining 1,855 companies that this rule affects are small businesses.

As we stated earlier, based on 2010 sales data, this rule will cost industry approximately \$78 million dollars per year. Small businesses accounted for about 20 percent of the royalties paid in 2010. Applying that percentage to industry costs, we estimate that the changes in this final rule will cost all small-business lessors approximately \$15,600,000 per year. The amount will vary for each company depending on the volume of production that each small business produces and sells each year.

In sum, we do not estimate that this rule will result in a significant economic effect on a substantial number of small entities because this rule will cost affected small businesses a collective total of \$15,600,000 per year. Therefore, a Regulatory Flexibility Analysis will not be required, and, accordingly, a Small Entity Compliance Guide will not be required.

Your comments are important. The Small Business and Agriculture

Regulatory Enforcement Ombudsman and ten Regional Fairness Boards receive comments from small businesses about Federal agency enforcement actions. The Ombudsman annually evaluates the enforcement activities and rates each agency's responsiveness to small business. If you wish to comment on ONRR's actions, call 1-(888) 734-3247. You may comment to the Small Business Administration without fear of retaliation. Allegations of discrimination/retaliation filed with the Small Business Administration will be investigated for appropriate action.

4. *Small Business Regulatory Enforcement Fairness Act*

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

a. Does not have an annual effect on the economy of \$100 million or more. We estimate that the maximum effect on all of industry will be \$84,850,000. The Summary of Royalty Impacts table, as shown in item 1 above, demonstrates that the economic impact on industry, State and local governments and the Federal government will be well below the \$100 million threshold that the Federal government uses to define a rule as having a significant impact on the economy.

b. Will not cause a major increase in costs or prices for consumers; individual industries; Federal, State, or local government agencies; or geographic regions. See item 1 above.

c. Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U. S.-based enterprises to compete with foreign-based enterprises. We are the only agency that promulgates rules for royalty valuation on Federal oil and gas leases and Federal and Indian coal leases.

5. *Unfunded Mandates Reform Act*

This rule does not impose an unfunded mandate on State, local, or Tribal governments or the private sector of more than \$100 million per year. This rule does not have a significant or unique effect on State, local, or Tribal governments or the private sector. We are not required to provide a statement containing the information that the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires because this rule is not an unfunded mandate. See item 1 above.

6. *Takings (E.O. 12630)*

Under the criteria in section 2 of E.O. 12630, this rule does not have any significant takings implications. This

rule will not impose conditions or limitations on the use of any private property. This rule will apply to Federal oil, Federal gas, Federal coal, and Indian coal leases only. Therefore, this rule does not require a Takings Implication Assessment.

7. *Federalism (E.O. 13132)*

Under the criteria in section 1 of E.O. 13132, this rule does not have sufficient Federalism implications to warrant the preparation of a Federalism summary impact statement. The management of Federal oil leases, Federal gas leases, and Federal and Indian coal leases is the responsibility of the Secretary of the Interior, and we distribute all of the royalties that we collect from the leases to States, Tribes, and individual Indian mineral owners. This rule does not impose administrative costs on States or local governments. This rule also does not substantially and directly affect the relationship between the Federal and State governments. Because this rule does not alter that relationship, this rule does not require a Federalism summary impact statement.

8. *Civil Justice Reform (E.O. 12988)*

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

a. Meets the criteria of section 3(a), which requires that we review all regulations to eliminate errors and ambiguity and write them to minimize litigation.

b. Meets the criteria of section 3(b)(2), which requires that we write all regulations in clear language using clear legal standards.

9. *Consultation With Indian Tribal Governments (E.O. 13175)*

Under the criteria in E.O. 13175, we evaluated this final rule and determined that it will have potential effects on Federally-recognized Indian Tribes. Specifically, this rule will change the valuation method for coal produced from Indian leases as discussed above. Accordingly:

(a) We held a public workshop on October 20, 2011, in Albuquerque, New Mexico, to consider Tribal comments on the Indian coal valuation regulations.

(b) We solicited and received comments from a Tribe through our Advance Notice of Proposed Rulemaking published on May 27, 2011 (76 FR 30881).

(c) We requested further comments from our Tribal partners through our bi-annual State and Tribal Royalty Audit Committee meetings held in May and November 2015.

(d) We considered Tribal views in this final rule.

10. *Paperwork Reduction Act*

This rule:

(a) Does not contain any new information collection requirements.

(b) Does not require a submission to the OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

This rule also refers to, but does not change, the information collection requirements that OMB already approved under OMB Control Numbers 1012-0004, 1012-0005, and 1012-0010. Since this rule is reorganizing our current regulations, please refer to the Derivations Table in Section II for specifics. The corresponding information collection burden tables will be updated during their normal renewal cycle. See 5 CFR 1320.4(a)(2).

11. *National Environmental Policy Act*

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. We are not required to provide a detailed statement under the National Environmental Policy Act of 1969 (NEPA) because this rule qualifies for a categorical exclusion under 43 CFR 46.210(c) and (i) and the DOI Departmental Manual, part 516, section 15.4.D: “(c) *Routine financial transactions including such things as . . . audits, fees, bonds, and royalties . . . (i) Policies, directives, regulations, and guidelines: That are of an administrative, financial, legal, technical, or procedural nature.*” We also have determined that this rule is not involved in any of the extraordinary circumstances listed in 43 CFR 46.215 that require further analysis under NEPA. The procedural changes resulting from these amendments will have no consequence on the physical environment. This rule does not alter, in any material way, natural resources exploration, production, or transportation.

12. *Effects on the Nation's Energy Supply (E.O. 13211)*

This rule is not a significant energy action under the definition in E.O. 13211; therefore, a Statement of Energy Effects is not required.

List of Subjects in 30 CFR Parts 1202 and 1206

Coal, Continental shelf, Government contracts, Indian lands, Mineral royalties, Natural gas, Oil, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

Dated: June 24, 2016.

Kristen J. Sarri,

Principal Deputy Assistant Secretary for Policy, Management and Budget.

Authority and Issuance

For the reasons discussed in the preamble, ONRR amends 30 CFR parts 1202 and 1206 as set forth below:

PART 1202—ROYALTIES

- 1. The authority citation for part 1202 continues to read as follows:

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

Subpart B—Oil, Gas, and OCS Sulfur, General

- 2. In § 1202.51, revise paragraph (b) to read as follows:

§ 1202.51 Scope and definitions.

* * * * *

(b) The definitions in § 1206.20 are applicable to subparts B, C, D, and J of this part.

Subpart F—Coal

- 3. Add § 1202.251 to subpart F to read as follows:

§ 1202.251 What coal is subject to royalties?

(a) All coal (except coal unavoidably lost as BLM determines under 43 CFR part 3400) from a Federal or Indian lease is subject to royalty. This includes coal used, sold, or otherwise disposed of by you on or off of the lease.

(b) If you receive compensation for unavoidably lost coal through insurance coverage or other arrangements, you must pay royalties at the rate specified in the lease on the amount of compensation that you receive for the coal. No royalty is due on insurance compensation that you received for other losses.

(c) If you rework waste piles or slurry ponds to recover coal, you must pay royalty at the rate specified in the lease at the time when you use, sell, or otherwise finally dispose of the recovered coal.

(1) The applicable royalty rate depends on the production method that you used to initially mine the coal contained in the waste pile or slurry pond (such as an underground mining method or a surface mining method).

(2) You must allocate coal in waste pits or slurry ponds that you initially mined from Federal or Indian leases to those Federal or Indian leases regardless

of whether it is stored on Federal or Indian lands.

(3) You must maintain accurate records demonstrating how to allocate the coal in the waste pit or slurry pond to each individual Federal or Indian coal lease.

PART 1206—PRODUCT VALUATION

- 4. The authority citation for part 1206 continues to read as follows:

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

- 5. Revise subpart A to read as follows:

Subpart A—General Provisions and Definitions

Sec.

1206.10 Has the Office of Management and Budget (OMB) approved the information collection requirements in this part?

1206.20 What definitions apply to this part?

Subpart A—General Provisions and Definitions

§ 1206.10 Has the Office of Management and Budget (OMB) approved the information collection requirements in this part?

OMB has approved the information collection requirement contained in this part under 44 U.S.C. 3501 *et seq.* See 30 CFR part 1210 for details concerning the estimated reporting burden and how to comment on the accuracy of the burden estimate.

§ 1206.20 What definitions apply to this part?

Ad valorem lease means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

Affiliate means a person who controls, is controlled by, or is under common control with another person. For the purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of non-control that ONRR may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, ONRR will consider each of the following factors to determine if there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors

(ii) With respect to the voting securities, or instruments of ownership or other forms of ownership: the percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, if a person is the greatest single owner, or if there is an opposing voting bloc of greater ownership

(iii) Operation of a lease, plant, pipeline, or other facility

(iv) The extent of others owners' participation in operations and day-to-day management of a lease, plant, or other facility

(v) Other evidence of power to exercise control over or common control with another person

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

ANS means Alaska North Slope.

Area means a geographic region at least as large as the limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

Arm's-length-contract means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's-length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

Audit means an examination, conducted under the generally accepted Governmental Auditing Standards, of royalty reporting and payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases or Indian leases.

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

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

BOEM means the Bureau of Ocean Energy Management of the Department of the Interior.

BSEE means the Bureau of Safety and Environmental Enforcement of the Department of the Interior.

Coal means coal of all ranks from lignite through anthracite.

Coal cooperative means an entity organized to provide coal or coal-related services to the entity's members (who may or may not also be owners of the entity), partners, and others. The entity may operate as a coal lessee, operator,

payor, logistics provider, or electricity generator, or any of their affiliates, and may be organized to be non-profit or for-profit.

Coal washing means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations, such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

Compression means the process of raising the pressure of gas.

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

Constraint means a reduction in, or elimination of, gas flow, deliveries, or sales required by the delivery system.

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

Designee means the person whom the lessee designates to report and pay the lessee's royalties for a lease.

Exchange agreement means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location. Exchange agreements may or may not specify prices for the oil involved. They frequently specify dollar amounts reflecting location, quality, or other differentials. Exchange agreements include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement. Examples of other types of exchange agreements include, but are not limited to, exchanges of produced oil for specific types of crude oil (such as West Texas Intermediate); exchanges of produced oil for other crude oil at other locations (Location Trades); exchanges of produced oil for other grades of oil (Grade Trades); and multi-party exchanges.

FERC means Federal Energy Regulatory Commission.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least the outermost boundaries of all oil and gas accumulations known within those reservoirs, vertically projected to the land surface. State oil and gas regulatory agencies usually name onshore fields and designate their

official boundaries. BOEM names and designates boundaries of OCS fields.

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

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

Gathering means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off of the lease, unit, or communitized area that BLM or BSEE approves for onshore and offshore leases, respectively, including any movement of bulk production from the wellhead to a platform offshore.

Geographic region means, for Federal gas, an area 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 and economic characteristics.

Gross proceeds means the total monies and other consideration accruing for the disposition of any of the following:

(1) *Oil*. Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government

(ii) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf

(iii) Reimbursements for harboring or terminalling fees, royalties, and any other reimbursements

(iv) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation

(v) Payments made to reduce or buy down the purchase price of oil produced in later periods by allocating such payments over the production whose price that the payment reduces and including the allocated amounts as proceeds for the production as it occurs

(vi) Monies and all other consideration to which a seller is contractually or legally entitled but does not seek to collect through reasonable efforts

(2) *Gas, residue gas, and gas plant products*. Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering that the lessee must perform at no cost to the Federal Government

(ii) Reimbursements for royalties, fees, and any other reimbursements

(iii) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation

(iv) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts

(3) *Coal*. Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oil, and other preparation of the coal that the lessee must perform at no cost to the Federal Government or Indian lessor

(ii) Reimbursements for royalties, fees, and any other reimbursements

(iii) Tax reimbursements even though the Federal or Indian royalty interest may be exempt from taxation

(iv) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts

Index means:

(1) For gas, the calculated composite price (\$/MMBtu) of spot market sales that a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes

(2) For oil, the calculated composite price (\$/barrel) of spot market sales that a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes.

Index pricing point means any point on a pipeline for which there is an index, which ONRR-approved publications may refer to as a trading location.

Index zone means a field or an area with an active spot market and published indices applicable to that field or an area that is acceptable to ONRR under § 1206.141(d)(1).

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

Individual Indian mineral owner means any Indian for whom minerals or

an interest in minerals is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Keepwhole contract means a processing agreement under which the processor delivers to the lessee a quantity of gas after processing equivalent to the quantity of gas that the processor received from the lessee prior to processing, normally based on heat content, less gas used as plant fuel and gas unaccounted for and/or lost. This includes, but is not limited to, agreements under which the processor retains all NGLs that it recovered from the lessee's gas.

Lease means any contract, profit-sharing arrangement, joint venture, or other agreement issued or approved by the United States under any mineral leasing law, including the Indian Mineral Development Act, 25 U.S.C. 2101–2108, that authorizes exploration for, extraction of, or removal of lease products. Depending on the context, lease may also refer to the land area that the authorization covers.

Lease products mean any leased minerals, attributable to, originating from, or allocated to a lease or produced in association with a lease.

Lessee means any person to whom the United States, an Indian Tribe, and/or individual Indian mineral owner issues a lease, and any person who has been assigned all or a part of record title, operating rights, or an obligation to make royalty or other payments required by the lease. Lessee includes:

(1) Any person who has an interest in a lease.

(2) In the case of leases for Indian coal or Federal coal, an operator, payor, or other person with no lease interest who makes royalty payments on the lessee's behalf.

Like quality means similar chemical and physical characteristics.

Location differential means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

Market center means a major point that ONRR recognizes for oil sales, refining, or transshipment. Market centers generally are locations where ONRR-approved publications publish oil spot prices.

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 for Federal oil and gas, and region for Federal and Indian coal.

Mine means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

Misconduct means any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior, regardless of the mental state of the lessee or any individual employed by or associated with the lessee.

Net output means the quantity of:

(1) For gas, residue gas and each gas plant product that a processing plant produces.

(2) For coal, the quantity of washed coal that a coal wash plant produces.

Netting means reducing the reported sales value to account for an allowance instead of reporting the allowance as a separate entry on the Report of Sales and Royalty Remittance (Form ONRR–2014) or the Solid Minerals Production and Royalty Report (Form ONRR–4430).

NGLs means Natural Gas Liquids.

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

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

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

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs, remains liquid at atmospheric pressure after passing through surface separating facilities, and is marketed or used as a liquid. Condensate recovered in lease separators or field facilities is oil.

ONRR means the Office of Natural Resources Revenue of the Department of the Interior.

ONRR-approved commercial price bulletin means a publication that ONRR approves for determining NGLs prices.

ONRR-approved publication means:

(1) For oil, a publication that ONRR approves for determining ANS spot prices or WTI differentials.

(2) For gas, a publication that ONRR approves for determining index pricing points.

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

Payor means any person who reports and pays royalties under a lease, regardless of whether that person also is a lessee.

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

Processing means any process designed to remove elements or compounds (hydrocarbon and non-hydrocarbon) 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. The use of a Joule-Thomson (JT) unit to remove NGLs from gas is considered processing regardless of where the JT unit is located, provided that you market the NGLs as NGLs.

Processing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for processing gas.

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

Quality differential means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

Region for coal means the eight Federal coal production regions, which the Bureau of Land Management designates as follows: Denver-Raton Mesa Region, Fort Union Region, Green River-Hams Fork Region, Powder River Region, San Juan River Region, Southern Appalachian Region, Uinta-Southwestern Utah Region, and Western Interior Region. See 44 FR 65197 (1979).

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

Rocky Mountain Region means the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and other oil-producing fields in the "Four Corners" area that lie within Colorado and Utah.

Roll means an adjustment to the NYMEX price that is calculated as follows: $\text{Roll} = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2)$, where: P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month; P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is December. December was the prompt month (for year 2011) from October 21 through November 18. January was the first month following the month of production, and February was the second month following the month of production. P_0 , therefore, is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between October 21 and November 18. P_1 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between October 21 and November 18. P_2 is the average of the daily NYMEX settlement prices for deliveries during February published for each business day between October 21 and November 18. In this example, assume that P_0 = \$95.08 per bbl, P_1 = \$95.03 per bbl, and P_2 = \$94.93 per bbl. In this example (a declining market), $\text{Roll} = .6667 \times (\$95.08 - \$95.03) + .3333 \times (\$95.08 - \$94.93) = \$0.03 + \$0.05 = \0.08 . You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is November.

November was the prompt month (for year 2012) from September 21 through October 22. December was the first month following the month of production, and January was the second month following the month of production. P_0 , therefore, is the average of the daily NYMEX settlement prices for deliveries during November published for each business day between September 21 and October 22. P_1 is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between September 21 and October 22. P_2 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between September 21 and October 22. In this example, assume that P_0 = \$91.28 per bbl, P_1 = \$91.65 per bbl, and P_2 = \$92.10 per bbl. In this example (a rising market), $\text{Roll} = .6667 \times (\$91.28 - \$91.65) + .3333 \times (\$91.28 - \$92.10) = (-\$0.25) + (-\$0.27) = (-\$0.52)$. You add this negative number to the NYMEX price (effectively, a subtraction from the NYMEX price).

Sale means a contract between two persons where:

(1) The seller unconditionally transfers title to the oil, gas, gas plant product, or coal to the buyer and does not retain any related rights, such as the right to buy back similar quantities of oil, gas, gas plant product, or coal from the buyer elsewhere;

(2) The buyer pays money or other consideration for the oil, gas, gas plant product, or coal; and

(3) The parties' intent is for a sale of the oil, gas, gas plant product, or coal to occur.

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.

Short ton means 2,000 pounds.

Spot price means the price under a spot sales contract where:

(1) A seller agrees to sell to a buyer a specified amount of oil at a specified price over a specified period of short duration.

(2) No cancellation notice is required to terminate the sales agreement.

(3) There is no obligation or implied intent to continue to sell in subsequent periods.

Tonnage means tons of coal measured in short tons.

Trading month means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business

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

Transportation allowance means a deduction in determining royalty value for the reasonable, actual costs that the lessee incurs for moving:

(1) Oil to a point of sale or delivery off of the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

(2) Unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off of the lease, unit area, or communitized area, or away from a processing plant. The transportation allowance does not include gathering costs.

(3) Coal to a point of sale remote from both the lease and mine or wash plant.

Washing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for coal washing.

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

■ 6. Revise subpart C to read as follows:

Subpart C—Federal Oil

Sec.

1206.100 What is the purpose of this subpart?

1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-length contract?

1206.102 How do I value oil not sold under an arm's-length contract?

1206.103 What publications does ONRR approve?

1206.104 How will ONRR determine if my royalty payments are correct?

1206.105 How will ONRR determine the value of my oil for royalty purposes?

- 1206.106 What records must I keep to support my calculations of value under this subpart?
- 1206.107 What are my responsibilities to place production into marketable condition and to market production?
- 1206.108 How do I request a valuation determination?
- 1206.109 Does ONRR protect information I provide?
- 1206.110 What general transportation allowance requirements apply to me?
- 1206.111 How do I determine a transportation allowance if I have an arm's-length transportation contract?
- 1206.112 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?
- 1206.113 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?
- 1206.114 How will ONRR identify market centers?
- 1206.115 What are my reporting requirements under an arm's-length transportation contract?
- 1206.116 What are my reporting requirements under a non-arm's-length transportation contract?
- 1206.117 What interest and penalties apply if I improperly report a transportation allowance?
- 1206.118 What reporting adjustments must I make for transportation allowances?
- 1206.119 How do I determine royalty quantity and quality?

Subpart C—Federal Oil

§ 1206.100 What is the purpose of this subpart?

(a) This subpart applies to all oil produced from Federal oil and gas leases onshore and on the OCS. It explains how you, as a lessee, must calculate the value of production for royalty purposes consistent with mineral leasing laws, other applicable laws, and lease terms.

(b) If you are a designee and if you dispose of production on behalf of a lessee, the terms “you” and “your” in this subpart refer to you and not to the lessee. In this circumstance, you must determine and report royalty value for the lessee's oil by applying the rules in this subpart to your disposition of the lessee's oil.

(c) If you are a designee and only report for a lessee and do not dispose of the lessee's production, references to “you” and “your” in this subpart refer to the lessee and not the designee. In this circumstance, you as a designee must determine and report royalty value for the lessee's oil by applying the rules in this subpart to the lessee's disposition of its oil.

(d) If the regulations in this subpart are inconsistent with a(an): Federal statute; settlement agreement between the United States and a lessee resulting

from administrative or judicial litigation; written agreement between the lessee and ONRR's Director establishing a method to determine the value of production from any lease that ONRR expects would at least approximate the value established under this subpart; express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(e) ONRR may audit, monitor, or review and adjust all royalty payments.

§ 1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-length contract?

(a) The value of oil under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the arm's-length contract less applicable allowances determined under § 1206.111 or § 1206.112. This value does not apply if you exercise an option to use a different value provided in paragraph (c)(1) or (c)(2)(i) of this section or if ONRR decides to value your oil under § 1206.105. You must use this paragraph (a) to value oil when:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract, unless you exercise the option provided in paragraph (c)(2)(i) of this section.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for each contract for the sale of oil produced from that lease.

(c)(1) If you enter into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, and following the exchange(s) that you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you may use either paragraph (a) of this section or § 1206.102 to value your production for royalty purposes. If you fail to make the election required under this paragraph, you may not make a retroactive election, and ONRR may decide your value under § 1206.105.

(i) If you use paragraph (a) of this section, your gross proceeds are the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s). You must

adjust your gross proceeds for any location or quality differential, or other adjustments, that you received or paid under the arm's-length exchange agreement(s). If ONRR determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, ONRR may decide your value under § 1206.105. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(ii) When you elect under § 1206.101(c)(1) to use paragraph (a) of this section or § 1206.102, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) sold under arm's-length contracts following arm's-length exchange agreements. You may not change your election more often than once every two years.

(2)(i) If you sell or transfer your oil production to your affiliate, and that affiliate or another affiliate then sells the oil under an arm's-length contract, you may use either paragraph (a) of this section or § 1206.102 to value your production for royalty purposes.

(ii) When you elect under paragraph (c)(2)(i) of this section to use paragraph (a) of this section or § 1206.102, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that your affiliates resell at arm's-length. You may not change your election more often than once every two years.

§ 1206.102 How do I value oil not sold under an arm's-length contract?

This section explains how to value oil that you may not value under § 1206.101 or that you elect under § 1206.101(c)(1) to value under this section, unless ONRR decides to value your oil under 1206.105. First, determine if paragraph (a), (b), or (c) of this section applies to production from your lease, or if you may apply paragraph (d) or (e) with ONRR's approval.

(a) *Production from leases in California or Alaska.* Value is the average of the daily mean ANS spot prices published in any ONRR-approved publication during the trading month most concurrent with the production month. For example, if the production month is June, calculate the average of the daily mean prices using the daily ANS spot prices published in the ONRR-approved publication for all of the business days in June.

(1) To calculate the daily mean spot price, you must average the daily high and low prices for the month in the selected publication.

(2) You must use only the days and corresponding spot prices for which such prices are published.

(3) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 1206.111.

(4) After you select an ONRR-approved publication, you may not select a different publication more often than once every two years, unless the publication you use is no longer published or ONRR revokes its approval of the publication. If you must change publications, you must begin a new two-year period.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options for valuing your production under different factual situations. You must consistently apply paragraph (b)(2) or (3) of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease or a portion of the lease is not part of a unit or communitization agreement) that you cannot value under § 1206.101 or that you elect under § 1206.101(c)(1) to value under this section.

(1) You may elect to value your oil under either paragraph (b)(2) or (3) of this section. After you select either paragraph (b)(2) or (3) of this section, you may not change to the other method more often than once every two years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new two-year period.

(2) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliate's arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliate's production from both Federal and non-Federal leases in the same field or area during that month.

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

(3) Value is the NYMEX price (without the roll), adjusted for applicable location and quality

differentials and transportation costs under § 1206.113.

(4) If you demonstrate to ONRR's satisfaction that paragraphs (b)(2) through (3) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, ONRR's Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.* (1) Value is the NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under § 1206.113.

(2) If ONRR's Director determines that the use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula that industry uses to calculate the roll changes, ONRR may terminate or modify the use of the roll under paragraph (c)(1) of this section at the end of each two-year period as of January 1, 2017, through a notice published in the **Federal Register** not later than 60 days before the end of the two-year period. ONRR will explain the rationale for terminating or modifying the use of the roll in this notice.

(d) *Unreasonable value.* If ONRR determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, ONRR may decide to value your oil under § 1206.105.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.* If ONRR determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, ONRR may decide to value your oil under § 1206.105.

§ 1206.103 What publications does ONRR approve?

(a) ONRR will periodically publish on www.onrr.gov a list of ONRR-approved publications for the NYMEX price and ANS spot price based on certain criteria including, but not limited to:

(1) Publications buyers and sellers frequently use.

(2) Publications frequently mentioned in purchase or sales contracts.

(3) Publications that use adequate survey techniques, including development of estimates based on daily surveys of buyers and sellers of crude oil, and, for ANS spot prices, buyers and sellers of ANS crude oil.

(4) Publications independent from ONRR, other lessors, and lessees.

(b) Any publication may petition ONRR to be added to the list of acceptable publications.

(c) ONRR will specify the tables that you must use in the acceptable publications.

(d) ONRR may revoke its approval of a particular publication if we determine that the prices or differentials published in the publication do not accurately represent NYMEX prices or differentials or ANS spot market prices or differentials.

§ 1206.104 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may direct you to use a different measure of royalty value or decide your value under § 1206.105.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, or report a credit for—or request a refund of—any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or to your affiliate for the oil. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under § 1206.105.

(c) ONRR may decide your value under § 1206.105 if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the oil for the mutual benefit of yourself and the lessor by selling your oil at a value that is unreasonably low. ONRR may consider a sales price to be unreasonably low if it is 10 percent less than the lowest reasonable measures of market price including—but not limited to—index prices and prices reported to ONRR for like quality oil; or

(3) ONRR cannot determine if you properly valued your oil under § 1206.101 or § 1206.102 for any reason including—but not limited to—your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the oil.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or in a timely manner, for a quantity of oil.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may determine your value under § 1206.105.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.105 How will ONRR determine the value of my oil for royalty purposes?

If ONRR decides that we will value your oil for royalty purposes under § 1206.104, or any other provision in this subpart, then we will determine value, for royalty purposes, by considering any information that we deem relevant, which may include, but is not limited to, the following:

(a) The value of like-quality oil in the same field or nearby fields or areas

(b) The value of like-quality oil from the refinery or area

(c) Public sources of price or market information that ONRR deems reliable

(d) Information available and reported to ONRR, including but not limited to on Form ONRR-2014 and the Oil and Gas Operations Report (Form ONRR-4054)

(e) Costs of transportation or processing if ONRR determines that they are applicable

(f) Any information that ONRR deems relevant regarding the particular lease operation or the salability of the oil

§ 1206.106 What records must I keep to support my calculations of value under this subpart?

If you determine the value of your oil under this subpart, you must retain all data relevant to the determination of royalty value.

(a) You must show both of the following:

(1) How you calculated the value that you reported, including all adjustments for location, quality, and transportation.

(2) How you complied with these rules.

(b) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(c) ONRR may review and audit your data, and ONRR will direct you to use a different value if we determine that the reported value is inconsistent with the requirements of this subpart.

§ 1206.107 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal government.

(b) If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.

§ 1206.108 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any oil produced. Your request must:

(1) Be in writing;

(2) Identify, specifically, all leases involved, all interest owners of those leases, the designee(s), and the operator(s) for those leases;

(3) Completely explain all relevant facts; you must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents);

(6) Suggest your proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a valuation determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to, the following:

(i) Requests for guidance on hypothetical situations

(ii) Matters that are the subject of pending litigation or administrative appeals

(c)(1) A valuation determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a valuation determination, you must make any adjustments to royalty payments that follow from the determination and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) A valuation determination that the Assistant Secretary signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701-706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary may use any of the applicable valuation criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR or the Assistant Secretary based any determination or guidance takes precedence over the determination or guidance, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the determination or guidance.

(g) ONRR or the Assistant Secretary generally will not retroactively modify or rescind a valuation determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.109.

§ 1206.109 Does ONRR protect information that I provide?

(a) Certain information that you or your affiliate submit(s) to ONRR regarding valuation of oil, including transportation allowances, may be exempt from disclosure.

(b) To the extent that applicable laws and regulations permit, ONRR will keep confidential any data that you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§ 1206.110 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport oil from the lease to the point off of the lease under § 1206.110, § 1206.111, or § 1206.112, as applicable. You may not deduct transportation costs that you incur to move a particular volume of production to reduce royalties that you owe on production for which you did not incur those costs. This paragraph applies when:

(1)(i) The movement to the sales point is not gathering.

(ii) For oil produced on the OCS, the movement of oil from the wellhead to the first platform is not transportation; and

(2) You value oil under § 1206.101 based on a sale at a point off of the lease, unit, or communitized area where the oil is produced; or

(3) You do not value your oil under § 1206.102(a)(3) or (b)(3).

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. If your or your affiliate's transportation contract includes more than one liquid product, you must allocate costs consistently and equitably to each of the liquid products that are transported. Your allocation must use the same proportion as the ratio of the volume of each liquid product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to ONRR a prospective cost allocation method

based on the values of the liquid products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the month when ONRR received your proposed procedure until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR-2014 for the months that you used the rejected method and pay any additional royalty due, plus late payment interest.

(c)(1) Where you or your affiliate transport(s) both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to ONRR.

(2) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR-2014 for the months when you used the rejected method and pay any additional royalty and interest due.

(3) You must submit your initial proposal, including all available data, within three months after you first claim the allocated deductions on Form ONRR-2014.

(d)(1) Your transportation allowance may not exceed 50 percent of the value of the oil, as determined under § 1206.101.

(2) If ONRR approved your request to take a transportation allowance in excess of the 50-percent limitation under former § 1206.109(c), that approval is terminated as January 1, 2017.

(e) You must express transportation allowances for oil as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate are paid to a dollar-value equivalent.

(f) ONRR may determine your transportation allowance under § 1206.105 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the oil for the mutual benefit of yourself and the lessor by transporting your oil at a cost that is unreasonably

high. We may consider a transportation allowance to be unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs including, but not limited to, transportation allowances reported to ONRR and tariffs for gas, residue gas, or gas plant product transported through the same system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.111 or § 1206.112 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(g) You do not need ONRR's approval before reporting a transportation allowance.

§ 1206.111 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred, as more fully explained in paragraph (b) of this section, except as provided in § 1206.110(f) and subject to the limitation in § 1206.110(d).

(2) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(3) You do not need ONRR's approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to, the following costs to determine your transportation allowance under paragraph (a) of this section; you may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section including, but not limited to:

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

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

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

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

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

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

(7) Transfer fees paid to a hub operator associated with physical

movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

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

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

(10) Hurricane surcharges that you or your affiliate actually pay(s).

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

(i) First, multiply the volume that the pipeline requires you to maintain—and that you do maintain—in the pipeline by the value of that volume for the current month calculated under § 1206.101 or § 1206.102, as applicable.

(ii) Second, multiply the value calculated under paragraph (b)(11)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 1206.112(i)(3) by 12.

(c) You may not include the following costs to determine your transportation allowance under paragraph (a) of this section:

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

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

(3) Title and terminal transfer fees

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

(5) Fees paid to brokers

(6) Fees paid to a scheduling service provider

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

(8) Gauging fees

(d) If you have no written contract for the arm's-length transportation of oil, then ONRR will determine your transportation allowance under § 1206.105. You may not use this paragraph (d) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.108(a).

(2) You may use that method to determine your allowance until ONRR issues its determination.

§ 1206.112 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (e), (f), and (g) of this section.

(2) Overhead under paragraph (h) of this section.

(3)(i) Depreciation and a return on undepreciated capital investment under paragraph (i)(1) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (i)(2) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(ii) A return on the reasonable salvage value under paragraph (i)(1)(iii) of this section after you have depreciated the transportation system to its reasonable salvage value.

(c) To the extent not included in costs identified in paragraphs (e) through (h) of this section.

(1) If you or your affiliate incur(s) the following actual costs under your or your affiliate's non-arm's-length contract, you may include these costs in your calculations under this section:

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

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

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

(iv) Fees paid to a non-affiliated quality bank administrator for administration of a quality bank

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

(A) First, multiply the volume that the pipeline requires you to maintain—and that you do maintain—in the pipeline by the value of that volume for the current month calculated under § 1206.101 or § 1206.102, as applicable.

(B) Second, multiply the value calculated under paragraph (c)(1)(v)(A) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 1206.112(i)(3) by 12.

(2) You may not include in your transportation allowance:

(i) Any of the costs identified under § 1206.111(c); and/or

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

(d) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(e) Allowable capital investment costs are generally those for depreciable fixed assets (including the costs of delivery and installation of capital equipment) that are an integral part of the transportation system.

(f) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expense that you can document.

(g) Allowable maintenance expenses include the following

(1) Maintenance of the transportation system.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

(h) 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.

(i)(1) To calculate depreciation and a return on undepreciated capital

investment, you may elect to use either a straight-line depreciation method (based on the life of equipment or on the life of the reserves that the transportation system services), or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(i) A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for purposes of the allowance calculation.

(ii) You may depreciate a transportation system, with or without a change in ownership, only once.

(iii)(A) To calculate the return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the transportation system multiplied by the rate of return that you determine under paragraph (i)(3) of this section.

(B) After you have depreciated a transportation system to the reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (i)(3) of this section.

(2) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use 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 (i)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(ii) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.113 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?

This section applies when you use NYMEX prices or ANS spot prices to calculate the value of production under § 1206.102. As specified in this section, you must adjust the NYMEX price to reflect the difference in value between your lease and Cushing, Oklahoma, or

adjust the ANS spot price to reflect the difference in value between your lease and the appropriate ONRR-recognized market center at which the ANS spot price is published (for example, Long Beach, California, or San Francisco, California). Paragraph (a) of this section explains how you adjust the value between the lease and the market center, and paragraph (b) of this section explains how you adjust the value between the market center and Cushing when you use NYMEX prices. Paragraph (c) of this section explains how adjustments may be made for quality differentials that are not accounted for through exchange agreements. Paragraph (d) of this section gives some examples. References in this section to "you" include your affiliates, as applicable.

(a) To adjust the value between the lease and the market center:

(1)(i) For oil that you exchange at arm's-length between your lease and the market center (or between any intermediate points between those locations), you must calculate a lease-to-market center differential by the applicable location and quality differentials derived from your arm's-length exchange agreement applicable to production during the production month.

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

(2) For oil that you transport between your lease and the market center (or between any intermediate points between those locations), you may take an allowance for the cost of transporting that oil between the relevant points, as determined under § 1206.111 or § 1206.112, as applicable.

(3) If you transport or exchange at arm's-length (or both transport and exchange) at least 20 percent—but not all—of your oil produced from the lease

to a market center, you must determine the adjustment between the lease and the market center for the oil that is not transported or exchanged (or both transported and exchanged) to or through a market center as follows:

(i) Determine the volume-weighted average of the lease-to-market center adjustment calculated under paragraphs (a)(1) and (2) of this section for the oil that you do transport or exchange (or both transport and exchange) from your lease to a market center.

(ii) Use that volume-weighted average lease-to-market center adjustment as the adjustment for the oil that you do not transport or exchange (or both transport and exchange) from your lease to a market center.

(4) If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to ONRR an adjustment between the lease and the market center for the portion of the oil that you do not transport or exchange (or both transport and exchange) to a market center. Until you obtain such approval, you may use your proposed adjustment. If ONRR prescribes a different adjustment, you must apply ONRR's adjustment to all periods for which you used your proposed adjustment. You must pay any additional royalties due resulting from using ONRR's adjustment, plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(5) You may not both take a transportation allowance and use a location and quality adjustment or exchange differential for the same oil between the same points.

(b) For oil that you value using NYMEX prices, you must adjust the value between the market center and Cushing, Oklahoma, as follows:

(1) If you have arm's-length exchange agreements between the market center and Cushing under which you exchange to Cushing at least 20 percent of all of the oil that you own at the market center during the production month, you must use the volume-weighted average of the location and quality differentials from those agreements as the adjustment between the market center and Cushing for all of the oil that you produce from the leases during that production month for which that market center is used.

(2) If paragraph (b)(1) of this section does not apply, you must use the WTI differential published in an ONRR-approved publication for the market center nearest to your lease, for crude oil most similar in quality to your

production, as the adjustment between the market center and Cushing. For example, for light sweet crude oil produced offshore of Louisiana, you must use the WTI differential for Light Louisiana Sweet crude oil at St. James, Louisiana. After you select an ONRR-approved publication, you may not select a different publication more often than once every two years, unless the publication you use is no longer published or ONRR revokes its approval of the publication. If you must change publications, you must begin a new two-year period.

(3) If neither paragraph (b)(1) nor (2) of this section applies, you may propose an alternative differential to ONRR. Until you obtain such approval, you may use your proposed differential. If ONRR prescribes a different differential, you must apply ONRR's differential to all periods for which you used your proposed differential. You must pay any additional royalties due resulting from using ONRR's differential, plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

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

(2) If the quality of your oil, as adjusted, is still different from the quality of the representative crude oil at the market center after making the quality adjustments described in paragraphs (a), (b), and (c)(1) of this section, you may make further gravity adjustments using posted price gravity tables. If quality bank adjustments do not incorporate or provide for adjustments for sulfur content, you may make sulfur adjustments, based on the quality of the representative crude oil at the market center, of 5.0 cents per one-tenth percent difference in sulfur content.

(i) You may request prior ONRR approval to use a different adjustment.

(ii) If ONRR approves your request to use a different quality adjustment, you may begin using that adjustment for the

production month following the month when ONRR received your request.

(d) The examples in this paragraph illustrate how to apply the requirement of this section.

(1) *Example.* Assume that a Federal lessee produces crude oil from a lease near Artesia, New Mexico. Further, assume that the lessee transports the oil to Roswell, New Mexico, and then exchanges the oil to Midland, Texas. Assume that the lessee refines the oil received in exchange at Midland. Assume that the NYMEX price is \$86.21/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is $-\$2.27/\text{bbl}$; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of $-\$0.08/\text{bbl}$; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is $\$0.40/\text{bbl}$. In this example, the royalty value of the oil is $\$86.21 - \$2.27 - \$0.08 - \$0.40 = \$83.46/\text{bbl}$.

(2) *Example.* Assume the same facts as in the example in paragraph (d)(1) of this section, except that the lessee transports and exchanges to Midland 40 percent of the production from the lease near Artesia and transports the remaining 60 percent directly to its own refinery in Ohio. In this example, the 40 percent of the production would be valued at $\$83.46/\text{bbl}$, as explained in the previous example. In this example, the other 60 percent also would be valued at $\$83.46/\text{bbl}$.

(3) *Example.* Assume that a Federal lessee produces crude oil from a lease near Bakersfield, California. Further, assume that the lessee transports the oil to Hynes Station and then exchanges the oil to Cushing, which it further exchanges with oil that it refines. Assume that the ANS spot price is $\$105.65/\text{bbl}$ and that the lessee's actual cost of transporting the oil from Bakersfield to Hynes Station is $\$0.28/\text{bbl}$. The lessee must request approval from ONRR for a location and quality adjustment between Hynes Station and Long Beach. For example, the lessee likely would propose using the tariff on Line 63 from Hynes Station to Long Beach as the adjustment between those points. Assume that adjustment to be $\$0.72$, including the sulfur and gravity bank adjustments, and that ONRR approves the lessee's request. In this example, the preliminary (because the location and quality adjustment is subject to ONRR's review) royalty value of the oil is $\$105.65 - \$0.72 - \$0.28 = \$104.65/\text{bbl}$. The fact that oil was exchanged to Cushing does not change the use of ANS spot prices for royalty valuation.

§ 1206.114 How will ONRR identify market centers?

ONRR will monitor market activity and, if necessary, add to or modify the list of market centers that we publish to www.onrr.gov. ONRR will consider the following factors and conditions in specifying market centers:

(a) Points where ONRR-approved publications publish prices useful for index purposes.

(b) Markets served.

(c) Input from industry and others knowledgeable in crude oil marketing and transportation.

(d) Simplification.

(e) Other relevant matters.

§ 1206.115 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on transportation costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.116 What are my reporting requirements under a non-arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on transportation costs that you or your affiliate incur(s).

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.118 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You may find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d) If you are authorized under § 1206.112(j) to use an exception to the requirement to calculate your actual transportation costs, you must follow the reporting requirements of § 1206.115.

§ 1206.117 What interest and penalties apply if I improperly report a transportation allowance?

(a) If you deduct a transportation allowance on Form ONRR–2014 that exceeds 50 percent of the value of the oil transported, you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, on the excess allowance amount taken from the date when that amount is taken to the date when you pay the additional royalties due.

(b) If you improperly net a transportation allowance against the oil instead of reporting the allowance as a separate entry on Form ONRR–2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.118 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount that you claimed on Form ONRR–2014 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual transportation allowance is greater than the amount that you claimed on Form ONRR–2014 for any month during the period reported on the allowance form, you are entitled to a credit plus interest.

§ 1206.119 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of oil as measured at the point of royalty settlement that BLM or BSEE approves for onshore leases and OCS leases, respectively.

(b) If you base the value of oil determined under this subpart on a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement that BLM or BSEE approves, you must adjust that value for the differences in quantity and/or quality.

(c) You may not make any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss that you sustain before the royalty settlement metering or measurement point is not subject to royalty if BLM or BSEE, whichever is appropriate, determines that such loss was unavoidable.

(d) You must pay royalties on 100 percent of the volume measured at the approved point of royalty settlement.

You may not claim a reduction in that measured volume for actual losses beyond the approved point of royalty settlement or for theoretical losses that you claim to have taken place either before or after the approved point of royalty settlement.

■ 7. Revise subpart D to read as follows:

Subpart D—Federal Gas

Sec.

1206.140 What is the purpose and scope of this subpart?

1206.141 How do I calculate royalty value for unprocessed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

1206.142 How do I calculate royalty value for processed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

1206.143 How will ONRR determine if my royalty payments are correct?

1206.144 How will ONRR determine the value of my gas for royalty purposes?

1206.145 What records must I keep in order to support my calculations of royalty under this subpart?

1206.146 What are my responsibilities to place production into marketable condition and to market production?

1206.147 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.148 How do I request a valuation determination?

1206.149 Does ONRR protect information that I provide?

1206.150 How do I determine royalty quantity and quality?

1206.151 [Reserved]

1206.152 What general transportation allowance requirements apply to me?

1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract?

1206.154 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

1206.155 What are my reporting requirements under an arm's-length transportation contract?

1206.156 What are my reporting requirements under a non-arm's-length transportation contract?

1206.157 What interest and penalties apply if I improperly report a transportation allowance?

1206.158 What reporting adjustments must I make for transportation allowances?

1206.159 What general processing allowances requirements apply to me?

1206.160 How do I determine a processing allowance if I have an arm's-length processing contract?

1206.161 How do I determine a processing allowance if I have a non-arm's-length processing contract?

1206.162 What are my reporting requirements under an arm's-length processing contract?

1206.163 What are my reporting requirements under a non-arm's-length processing contract?

1206.164 What interest and penalties apply if I improperly report a processing allowance?

1206.165 What reporting adjustments must I make for processing allowances?

Subpart D—Federal Gas

§ 1206.140 What is the purpose and scope of this subpart?

(a) This subpart applies to all gas produced from Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS). It explains how you, as a lessee, must calculate the value of production for royalty purposes consistent with mineral leasing laws, other applicable laws, and lease terms.

(b) The terms “you” and “your” in this subpart refer to the lessee.

(c) If the regulations in this subpart are inconsistent with a(an): Federal statute; settlement agreement between the United States and a lessee resulting from administrative or judicial litigation; written agreement between the lessee and ONRR's Director establishing a method to determine the value of production from any lease that ONRR expects would at least approximate the value established under this subpart; express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR may audit and order you to adjust all royalty payments.

§ 1206.141 How do I calculate royalty value for unprocessed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) This section applies to unprocessed gas. Unprocessed gas is:

(1) Gas that is not processed;

(2) Any gas that you are not required to value under § 1206.142 or that ONRR does not value under § 1206.144; or

(3) Any gas that you sell prior to processing based on a price per MMBtu or Mcf when the price is not based on the residue gas and gas plant products.

(b) The value of gas under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less a transportation allowance determined under § 1206.152. This value does not apply if you exercise the option in paragraph (c) of this section or if ONRR decides to value your gas under § 1206.144. You must use this paragraph (b) to value gas when:

(1) You sell under an arm's-length contract;

(2) You sell or transfer unprocessed gas to your affiliate or another person under a non-arm's-length contract and

that affiliate or person, or an affiliate of either of them, then sells the gas under an arm's-length contract, unless you exercise the option provided in paragraph (c) of this section;

(3) You, your affiliate, or another person sell(s) unprocessed gas produced from a lease under multiple arm's-length contracts, and that gas is valued under this paragraph. Unless you exercise the option provided in paragraph (c) of this section, the value of the gas is the volume-weighted average of the values, established under this paragraph, for each contract for the sale of gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price that the pipeline must pay you or your affiliate under the transportation contract. You must use the same value for volumes that exceed the over-delivery tolerances, even if those volumes are subject to a lower price under the transportation contract.

(c) If you do not sell under an arm's-length contract, you may elect to value your gas under this paragraph (c). You may not change your election more often than once every two years.

(1)(i) If you can only transport gas to one index pricing point published in an ONRR-approved publication, available at www.onrr.gov, your value, for royalty purposes, is the highest reported monthly bidweek price for that index pricing point for the production month.

(ii) If you can transport gas to more than one index pricing point published in an ONRR-approved publication available at www.onrr.gov, your value, for royalty purposes, is the highest reported monthly bidweek price for the index pricing points to which your gas could be transported for the production month, whether or not there are constraints for that production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your gas enters the pipeline.

(iv) You must reduce the number calculated under paragraphs (c)(1)(i) and (ii) of this section by 5 percent for sales from the OCS Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

(v) After you select an ONRR-approved publication available at www.onrr.gov, you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-

approved publication if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish a list of excluded index pricing points available at www.onrr.gov.

(2) You may not take any other deductions from the value calculated under this paragraph (c).

(d) If some of your gas is used, lost, unaccounted for, or retained as a fee under the terms of a sales or service agreement, that gas will be valued for royalty purposes using the same royalty valuation method for valuing the rest of the gas that you do sell.

(e) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point for the gas, then you must value your gas under paragraph (c) of this section; or

(2) There is not an index pricing point for the gas, then ONRR will decide the value under § 1206.144.

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues our decision.

(iii) After ONRR issues our determination, you must make the adjustments under § 1206.143(a)(2).

§ 1206.142 How do I calculate royalty value for processed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) This section applies to the valuation of processed gas, including but not limited to:

(1) Gas that you or your affiliate do not sell, or otherwise dispose of, under an arm's-length contract prior to processing.

(2) Gas where your or your affiliate's arm's-length contract for the sale of gas prior to processing provides for payment to be determined on the basis of the value of any products resulting from processing, including residue gas or natural gas liquids.

(3) Gas that you or your affiliate process under an arm's-length keepwhole contract.

(4) Gas where your or your affiliate's arm's-length contract includes a reservation of the right to process the gas, and you or your affiliate exercise(s) that right.

(b) The value of gas subject to this section, for royalty purposes, is the combined value of the residue gas and all gas plant products that you determine under this section plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to

processing that you determine under subpart C of this part less applicable transportation and processing allowances that you determine under this subpart, unless you exercise the option provided in paragraph (d) of this section.

(c) The value of residue gas or any gas plant product under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract. This value does not apply if you exercise the option provided in paragraph (d) of this section, or if ONRR decides to value your residue gas or any gas plant product under § 1206.144. You must use this paragraph (c) to value residue gas or any gas plant product when:

(1) You sell under an arm's-length contract;

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the residue gas or any gas plant product under an arm's-length contract, unless you exercise the option provided in paragraph (d) of this section;

(3) You, your affiliate, or another person sell(s), under multiple arm's-length contracts, residue gas or any gas plant products recovered from gas produced from a lease that you value under this paragraph. In that case, unless you exercise the option provided in paragraph (d) of this section, because you sold non-arm's-length to your affiliate or another person, the value of the residue gas or any gas plant product is the volume-weighted average of the gross proceeds established under this paragraph for each arm's-length contract for the sale of residue gas or any gas plant products recovered from gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price that the pipeline must pay to you or your affiliate under the transportation contract. You must use the same value for volumes that exceed the over-delivery tolerances, even if those volumes are subject to a lower price under the transportation contract.

(d) If you do not sell under an arm's-length contract, you may elect to value your residue gas and NGLs under this paragraph (d). You may not change your election more often than once every two years.

(1)(i) If you can only transport residue gas to one index pricing point published in an ONRR-approved publication available at www.onrr.gov, your value,

for royalty purposes, is the highest reported monthly bidweek price for that index pricing point for the production month.

(ii) If you can transport residue gas to more than one index pricing point published in an ONRR-approved publication available at www.onrr.gov, your value, for royalty purposes, is the highest reported monthly bidweek price for the index pricing points to which your gas could be transported for the production month, whether or not there are constraints, for the production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your residue gas enters the pipeline.

(iv) You must reduce the number calculated under paragraphs (d)(1)(i) and (ii) of this section by 5 percent for sales from the OCS Gulf of Mexico and by 10 percent for sales from all other areas, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

(v) After you select an ONRR-approved publication available at www.onrr.gov, you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-approved publication if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish a list of excluded index pricing points on www.onrr.gov.

(2)(i) If you sell NGLs in an area with one or more ONRR-approved commercial price bulletins available at www.onrr.gov, you must choose one bulletin, and your value, for royalty purposes, is the monthly average price for that bulletin for the production month.

(ii) You must reduce the number calculated under paragraph (d)(2)(i) of this section by the amounts that ONRR posts at www.onrr.gov for the geographic location of your lease. The methodology that ONRR will use to calculate the amounts is set forth in the preamble to this regulation. This methodology is binding on you and ONRR. ONRR will update the amounts periodically using this methodology.

(iii) After you select an ONRR-approved commercial price bulletin available at www.onrr.gov, you may not select a different commercial price bulletin more often than once every two years.

(3) You may not take any other deductions from the value calculated under this paragraph (d).

(4) ONRR will post changes to any of the rates in this paragraph (d) on its Web site.

(e) If some of your gas or gas plant products are used, lost, unaccounted for, or retained as a fee under the terms of a sales or service agreement, that gas will be valued for royalty purposes using the same royalty valuation method for valuing the rest of the gas or gas plant products that you do sell.

(f) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point or commercial price bulletin for the gas, then you must value your gas under paragraph (d) of this section.

(2) There is not an index pricing point or commercial price bulletin for the gas, then ONRR will determine the value under § 1206.144.

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues our decision.

(iii) After ONRR issues our determination, you must make the adjustments under § 1206.143(a)(2).

§ 1206.143 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value or decide your value under § 1206.144.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the gas, residue gas, or gas plant products. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under § 1206.144.

(c) ONRR may decide your value under § 1206.144 if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor by selling your gas, residue gas, or gas plant products at a value that is unreasonably low. ONRR may consider a sales price unreasonably low if it is 10 percent less than the lowest reasonable measures of market price, including, but not limited to, index prices and prices reported to ONRR for like-quality gas, residue gas, or gas plant products; or

(3) ONRR cannot determine if you properly valued your gas, residue gas, or gas plant products under § 1206.141 or § 1206.142 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the gas, residue gas, or gas plant products.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or in a timely manner, for a quantity of gas, residue gas, or gas plant products.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide your value under § 1206.144.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.144 How will ONRR determine the value of my gas for royalty purposes?

If ONRR decides to value your gas, residue gas, or gas plant products for royalty purposes under § 1206.143, or any other provision in this subpart, then ONRR will determine the value, for royalty purposes, by considering any information that we deem relevant, which may include, but is not limited to:

(a) The value of like-quality gas in the same field or nearby fields or areas.

(b) The value of like-quality residue gas or gas plant products from the same plant or area.

(c) Public sources of price or market information that ONRR deems to be reliable.

(d) Information available or reported to ONRR, including, but not limited to, on Form ONRR-2014 and Form ONRR-4054.

(e) Costs of transportation or processing if ONRR determines that they are applicable.

(f) Any information that ONRR deems relevant regarding the particular lease operation or the salability of the gas.

§ 1206.145 What records must I keep in order to support my calculations of royalty under this subpart?

If you value your gas under this subpart, you must retain all data relevant to the determination of the royalty that you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR. You must comply with any such requirement within the time that ONRR specifies.

§ 1206.146 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place gas, residue gas, and gas plant products in marketable condition and market the gas, residue gas, and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal government.

(b) If you use gross proceeds under an arm's-length contract to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform in order to place the gas, residue gas, and gas plant products in marketable condition or to market the gas.

§ 1206.147 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR does not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR re-determining royalty due, under this subpart, final or binding as against the Federal government or its beneficiaries unless ONRR chooses to, in writing, formally close the audit period.

§ 1206.148 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any gas produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, the designee(s), and the operator(s) for those leases;

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments to royalty payments that follow from the determination, and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) A determination that the Assistant Secretary signs is the final action of the

Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.149.

§ 1206.149 Does ONRR protect information that I provide?

(a) Certain information that you or your affiliate submit(s) to ONRR regarding royalties on gas, including deductions and allowances, may be exempt from disclosure.

(b) To the extent that applicable laws and regulations permit, ONRR will keep confidential any data that you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§ 1206.150 How do I determine royalty quantity and quality?

(a)(1) You must calculate royalties based on the quantity and quality of unprocessed gas as measured at the point of royalty settlement that BLM or BSEE approves for onshore leases and OCS leases, respectively.

(2) If you base the value of gas determined under this subpart on a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement that BLM or BSEE approves, you must adjust that

value 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 you value residue gas and/or gas plant products determined under this subpart on 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 under paragraph (c) of this section, you must adjust that value for the differences in quantity and/or quality.

(c) You must determine the quantity of the residue gas and gas plant products attributable to a lease based on the following procedure:

(1) When you derive the net output of the processing plant from gas obtained from only one lease, you must base the quantity of the residue gas and gas plant products for royalty computation on the net output of the plant.

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

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of non-uniform content:

(i) You must determine the quantity of the residue gas allocable to each lease by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing that arithmetical product 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.

(ii) You must determine the net output of gas plant products allocable to each lease by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, dividing that arithmetical product 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) You may request prior ONRR approval of other methods for determining the quantity of residue gas and gas plant products allocable to each

lease. If approved, you must apply that method to all gas production from Federal leases that is processed in the same plant. You must do so beginning with the production month following the month when ONRR received your request to use another method.

(d)(1) You may not make any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that you sustain before the royalty settlement meter or measurement point is not subject to royalty if BLM or BSEE, whichever is appropriate, determines that such loss was unavoidable.

(2) Except as provided in paragraph (d)(1) of this section and § 1206.151(c) of this chapter, you must pay royalties due on 100 percent of the volume determined under paragraphs (a) through (c) of this section. You may not reduce that determined volume for actual losses after you have determined the quantity basis, or for theoretical losses that you claim 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. You may not take any deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after you have determined the quantity basis or for theoretical losses that you claim to have taken place.

§ 1206.151 [Reserved]

§ 1206.152 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport residue gas, gas plant products, or unprocessed gas from the lease to the point off of the lease under § 1206.153 or § 1206.154, as applicable. You may not deduct transportation costs that you incur when moving a particular volume of production to reduce royalties that you owe on production for which you did not incur those costs. This paragraph applies when:

(1) You value unprocessed gas under § 1206.141(b) or residue gas and gas plant products under § 1206.142(b) based on a sale at a point off of the lease, unit, or communitized area where the residue gas, gas plant products, or unprocessed gas is produced; and

(2)(i) The movement to the sales point is not gathering.

(ii) For gas produced on the OCS, the movement of gas from the wellhead to the first platform is not transportation.

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each

product through each individual transportation system. If your or your affiliate's transportation contract includes more than one product in a gaseous phase, you must allocate costs consistently and equitably to each of the products transported. Your allocation must use the same proportion as the ratio of the volume of each product (excluding waste products with no value) to the volume of all products in the gaseous phase (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to ONRR a prospective cost allocation method based on the values of the products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the production month following the month when ONRR received your proposed procedure until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR-2014 for the months when you used the rejected method and pay any additional royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(c)(1) Where you or your affiliate transport(s) both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to ONRR.

(2) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR-2014 for the months when you used the rejected method and pay any additional royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) You must submit your initial proposal, including all available data, within three months after you first claim the allocated deductions on Form ONRR-2014.

(d) If you value unprocessed gas under § 1206.141(c) or residue gas and gas plant products under § 1206.142 (d), you may not take a transportation allowance.

(e)(1) Your transportation allowance may not exceed 50 percent of the value of the residue gas, gas plant products, or unprocessed gas as determined under § 1206.141 or § 1206.142.

(2) If ONRR approved your request to take a transportation allowance in

excess of the 50-percent limitation under former § 1206.156(c)(3), that approval is terminated as of January 1, 2017.

(f) You must express transportation allowances for residue gas, gas plant products, or unprocessed gas as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate are/is paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under § 1206.144 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor by transporting your gas, residue gas, or gas plant products at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs, including, but not limited to, transportation allowances reported to ONRR and tariffs for gas, residue gas, or gas plant products transported through the same system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.153 or § 1206.154 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(h) You do not need ONRR's approval before reporting a transportation allowance.

§ 1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred, as more fully explained in paragraph (b) of this section, except as provided in § 1206.152(g) and subject to the limitation in § 1206.152(e).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to, the following costs to determine your

transportation allowance under paragraph (a) of this section; you may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(1) *Firm demand charges paid to pipelines.* You may deduct firm demand charges or capacity reservation fees that you or your affiliate paid to a pipeline, including charges or fees for unused firm capacity that you or your affiliate have not sold before you report your allowance. If you or your affiliate receive(s) a payment from any party for release or sale of firm capacity after reporting a transportation allowance that included the cost of that unused firm capacity, or if you or your affiliate receive(s) a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on Form ONRR-2014 by the amount of that payment. You must modify Form ONRR-2014 by the amount received or credited for the affected reporting period and pay any resulting royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

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

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

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

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

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

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* Theoretical losses are not deductible in transportation arrangements unless the transportation allowance is based on arm's-length transportation rates charged under a FERC or State regulatory-approved tariff. If you or your

affiliate receive(s) volumes or credit for line gain, you must reduce your transportation allowance accordingly and pay any resulting royalties plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter;

(8) *Temporary storage services.* This includes short-duration storage services that market centers or hubs (commonly referred to as "parking" or "banking") offer or other temporary storage services that pipeline transporters provide, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or fewer.

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* ONRR allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under § 1206.146.

(10) *Costs of surety.* You may deduct the costs of securing a letter of credit, or other surety, that the pipeline requires you or your affiliate, as a shipper, to maintain under a transportation contract.

(11) *Hurricane surcharges.* You may deduct hurricane surcharges that you or your affiliate actually pay(s).

(c) You may not include the following costs to determine your transportation allowance under paragraph (a) of this section:

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

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

(3) *Penalties that you or your affiliate incur(s) as a shipper.* These penalties include, but are not limited to:

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

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

(iii) *Imbalance penalties.* This includes penalties that you or your affiliate incur(s) (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes

scheduled or nominated at a receipt or delivery point.

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

(4) *Intra-hub transfer fees.* These are fees that you or your affiliate pay(s) to hub operators for administrative services (such as title transfer tracking) necessary to account for the sale of gas within a hub.

(5) *Fees paid to brokers.* This includes fees that you or your affiliate pay(s) to parties who arrange marketing or transportation, if such fees are separately identified from aggregator/marketer fees.

(6) *Fees paid to scheduling service providers.* This includes fees that you or your affiliate pay(s) to parties who provide scheduling services, if such fees are separately identified from aggregator/marketer fees.

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

(8) *Other non-allowable costs.* Any cost you or your affiliate incur(s) for services that you are required to provide at no cost to the lessor, including, but not limited to, costs to place your gas, residue gas, or gas plant products into marketable condition disallowed under § 1206.146 and costs of boosting residue gas disallowed under § 1202.151(b).

(d) If you have no written contract for the transportation of gas, then ONRR will determine your transportation allowance under § 1206.144. You may not use this paragraph (d) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.148(a).

(2) You may use that method to determine your allowance until ONRR issues its determination.

§ 1206.154 How do I determine a transportation allowance if I have a non-arm's-length transportation contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (e), (f), and (g) of this section.

(2) Overhead under paragraph (h) of this section.

(3) Depreciation and a return on undepreciated capital investment under paragraph (i)(1) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (i)(2) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(4) A return on the reasonable salvage value under paragraph (i)(1)(iii) of this section, after you have depreciated the transportation system to its reasonable salvage value.

(c)(1) To the extent not included in costs identified in paragraphs (e) through (g) of this section, if you or your affiliate incur(s) the actual transportation costs listed under § 1206.153(b)(2), (5), and (6) under your or your affiliate's non-arm's-length contract, you may include those costs in your calculations under this section. You may not include any of the other costs identified under § 1206.153(b).

(2) You may not include in your calculations under this section any of the non-allowable costs listed under § 1206.153(c).

(d) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(e) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transportation system.

(f) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expense that you can document.

(g) Allowable maintenance expenses include the following:

(1) Maintenance of the transportation system.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

(h) 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.

(i)(1) To calculate depreciation and a return on undepreciated capital investment, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves that the transportation system services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(i) A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for the purposes of the allowance calculation.

(ii) You may depreciate a transportation system only once with or without a change in ownership.

(iii)(A) To calculate the return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the transportation system multiplied by the rate of return that you determine under paragraph (i)(3) of this section.

(B) After you have depreciated a transportation system to the reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (i)(3) of this section.

(2) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use 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 (i)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average BBB rate that Standard & Poor's

publishes for the first month for which the allowance is applicable.

(ii) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.155 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on transportation costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.156 What are my reporting requirements under a non-arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on non-arm's-length transportation costs that you or your affiliate incur(s).

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.158 applies when you amend your report based on your actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.157 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit, with interest.

(b) If you deduct a transportation allowance on Form ONRR-2014 that exceeds 50 percent of the value of the gas, residue gas, or gas plant products transported, you must pay late payment interest on the excess allowance amount taken from the date when that amount

is taken until the date when you pay the additional royalties due.

(c) If you improperly net a transportation allowance against the sales value of the residue gas, gas plant products, or unprocessed gas instead of reporting the allowance as a separate entry on Form ONRR-2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.158 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount that you claimed on Form ONRR-2014 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual transportation allowance is greater than the amount that you claimed on Form ONRR-2014 for any month during the period reported on the allowance form, you are entitled to a credit, plus interest.

§ 1206.159 What general processing allowances requirements apply to me?

(a)(1) When you value any gas plant product under § 1206.142(c), you may deduct from the value the reasonable, actual costs of processing.

(2) You do not need ONRR's approval before reporting a processing allowance.

(b) You must allocate processing costs among the gas plant products. You must determine a separate processing allowance for each gas plant product and processing plant relationship. ONRR considers NGLs to be one product.

(c)(1) You may not apply the processing allowance against the value of the residue gas.

(2) The processing allowance deduction on the basis of an individual product may not exceed 66⅔ percent of the value of each gas plant product determined under § 1206.142(c). Before you calculate the 66⅔-percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under § 1206.152.

(3) If ONRR approved your request to take a processing allowance in excess of the limitation in paragraph (c)(2) of this section under former § 1206.158(c)(3), that approval is terminated as of January 1, 2017.

(4) If ONRR approved your request to take an extraordinary cost processing allowance under former § 1206.158(d), ONRR terminates that approval as of January 1, 2017.

(d)(1) ONRR will not allow a processing cost deduction for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant.

(2) Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," ONRR will not allow processing cost deductions for such costs unless the acid gases removed are further processed into a gas plant product.

(i) In such event, you are eligible for a processing allowance determined under this subpart.

(ii) ONRR will not grant any processing allowance for processing lease production that is not royalty bearing.

(e) ONRR may determine your processing allowance under § 1206.144 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length processing contract does not reflect the reasonable cost of the processing because you breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor by processing your gas, residue gas, or gas plant products at a cost that is unreasonably high. We may consider a processing allowance unreasonably high if it is 10 percent higher than the highest reasonable measures of processing costs, including, but not limited to, processing allowances reported to ONRR; or

(3) ONRR cannot determine if you properly calculated a processing allowance under § 1206.160 or § 1206.161 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

§ 1206.160 How do I determine a processing allowance if I have an arm's-length processing contract?

(a)(1) If you or your affiliate incur processing costs under an arm's-length processing contract, you may claim a processing allowance for the reasonable, actual costs incurred, as more fully explained in paragraph (b) of this section, except as provided in paragraphs (a)(3)(i) and (a)(3)(ii) of this section and subject to the limitation in § 1206.159(c)(2).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(b)(1) If your or your affiliate's arm's-length processing contract includes

more than one gas plant product, and you can determine the processing costs for each product based on the contract, then you must determine the processing costs for each gas plant product under the contract.

(2) If your or your affiliate's arm's-length processing contract includes more than one gas plant product, and you cannot determine the processing costs attributable to each product from the contract, you must propose an allocation procedure to ONRR.

(i) You may use your proposed allocation procedure until ONRR issues its determination.

(ii) You must submit all relevant data to support your proposal.

(iii) ONRR will determine the processing allowance based upon your proposal and any additional information that ONRR deems necessary.

(iv) You must submit the allocation proposal within three months of claiming the allocated deduction on Form ONRR-2014.

(3) You may not take an allowance for the costs of processing lease production that is not royalty-bearing.

(4) If your or your affiliate's payments for processing under an arm's-length contract are not based on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(c) If you have no written contract for the arm's-length processing of gas, then ONRR will determine your processing allowance under § 1206.144. You may not use this paragraph (c) if you or your affiliate perform(s) your own processing.

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.148(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§ 1206.161 How do I determine a processing allowance if I have a non-arm's-length processing contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Depreciation and a return on undepreciated capital investment in

accordance with paragraph (h)(1) of this section, or you may elect to use a cost equal to the initial depreciable capital investment in the processing plant under paragraph (h)(2) of this section.

After you have elected to use either method for a processing plant, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(4) A return on the reasonable salvage value under paragraph (h)(1)(iii) of this section, after you have depreciated the processing plant to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the processing plant.

(e) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expense that you can document.

(f) Allowable maintenance expenses may include the following:

(1) Maintenance of the processing plant.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

(g) 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 and other fees, including royalties, are not allowable expenses.

(h)(1) To calculate depreciation and a return on undepreciated capital investment, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves that the processing plant services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If

ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(i) A change in ownership of a processing plant will not alter the depreciation schedule that the original processor/lessee established for purposes of the allowance calculation.

(ii) You may depreciate a processing plant only once with or without a change in ownership.

(iii)(A) To calculate a return on undepreciated capital investment, you may use an amount equal to the undepreciated capital investment in the processing plant multiplied by the rate of return that you determine under paragraph (h)(3) of this section.

(B) After you have depreciated a processing plant to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (h)(3) of this section.

(2) You may use 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 (h)(3) of this section. You may not include depreciation in your allowance.

(3) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(i) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(ii) You must re-determine the rate at the beginning of each subsequent calendar year.

(i)(1) You must determine the processing allowance for each gas plant product based on your or your affiliate's reasonable and actual cost of processing the gas. You must base your allocation of costs to each gas plant product upon generally accepted accounting principles.

(2) You may not take an allowance for processing lease production that is not royalty-bearing.

(j) You may apply for an exception from the requirement to calculate actual costs under paragraphs (a) and (b) of this section.

(1) ONRR will grant the exception if:

(i) You have or your affiliate 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.

(2) If ONRR grants the exception, you must use as your processing allowance the volume-weighted average prices charged to other persons under arm's-length contracts for processing at the same plant.

§ 1206.162 What are my reporting requirements under an arm's-length processing contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on arm's-length processing costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length processing contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.163 What are my reporting requirements under a non-arm's-length processing contract?

(a) You must use a separate entry on Form ONRR-2014 to notify ONRR of an allowance based on non-arm's-length processing costs that you or your affiliate incur(s).

(b)(1) For new non-arm's-length processing facilities or arrangements, you must base your initial deduction on estimates of allowable gas processing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the processing plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar processing plants.

(3) Section 1206.165 applies when you amend your report based on your actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d) If you are authorized under § 1206.161(j) to use an exception to the requirement to calculate your actual processing costs, you must follow the reporting requirements of § 1206.162.

§ 1206.164 What interest and penalties apply if I improperly report a processing allowance?

(a)(1) If ONRR determines that you took an unauthorized processing allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(2) If you understated your processing allowance, you may be entitled to a credit, with interest.

(b) If you deduct a processing allowance on Form ONRR-2014 that exceeds 66⅔ percent of the value of a gas plant product, you must pay late payment interest on the excess allowance amount taken from the date when that amount is taken until the date when you pay the additional royalties due.

(c) If you improperly net a processing allowance against the sales value of a gas plant product instead of reporting the allowance as a separate entry on Form ONRR-2014, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.165 What reporting adjustments must I make for processing allowances?

(a) If your actual processing allowance is less than the amount that you claimed on Form ONRR-2014 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual processing allowance is greater than the amount that you claimed on Form ONRR-2014 for any month during the period reported on the allowance form, you are entitled to a credit, plus interest.

■ 8. Revise subpart F to read as follows:

Subpart F—Federal Coal

Sec.

1206.250 What is the purpose and scope of this subpart?

1206.251 How do I determine royalty quantity and quality?

1206.252 How do I calculate royalty value for coal that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

1206.253 How will ONRR determine if my royalty payments are correct?

1206.254 How will ONRR determine the value of my coal for royalty purposes?

1206.255 What records must I keep in order to support my calculations of royalty under this subpart?

1206.256 What are my responsibilities to place production into marketable condition and to market production?

1206.257 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.258 How do I request a valuation determination?

1206.259 Does ONRR protect information that I provide?

1206.260 What general transportation allowance requirements apply to me?

1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

1206.262 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

1206.263 What are my reporting requirements under an arm's-length transportation contract?

1206.264 What are my reporting requirements under a non-arm's-length transportation contract?

1206.265 What interest and penalties apply if I improperly report a transportation allowance?

1206.266 What reporting adjustments must I make for transportation allowances?

1206.267 What general washing allowance requirements apply to me?

1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

1206.269 How do I determine washing allowances if I do not have an arm's-length washing contract?

1206.270 What are my reporting requirements under an arm's-length washing contract?

1206.271 What are my reporting requirements under a non-arm's-length washing contract?

1206.272 What interest and penalties apply if I improperly report a washing allowance?

1206.273 What reporting adjustments must I make for washing allowances?

Subpart F—Federal Coal

§ 1206.250 What is the purpose and scope of this subpart?

(a) This subpart applies to all coal produced from Federal coal leases. It explains how you, as the lessee, must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) The terms “you” and “your” in this subpart refer to the lessee.

(c) If the regulations in this subpart are inconsistent with a(an): Federal statute; settlement agreement between the United States and a lessee resulting from administrative or judicial litigation; written agreement between the lessee and ONRR's Director establishing a method to determine the value of production from any lease that ONRR expects, at least, would approximate the value established under this subpart; or express provision of a coal lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR may audit and order you to adjust all royalty payments.

§ 1206.251 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of coal at the royalty measurement point that ONRR and BLM jointly determine.

(b) You must measure coal in short tons using the methods that BLM

prescribes for Federal coal leases under 43 CFR part 3000. You must report coal quantity on appropriate forms required in 30 CFR part 1210—Forms and Reports.

(c)(1) You are not required to pay royalties on coal that you produce and add to stockpiles or inventory until you use, sell, or otherwise finally dispose of such coal.

(2) ONRR may request that BLM require you to increase your lease bond if BLM determines that stockpiles or inventory are excessive such that they increase the risk of resource degradation.

(d) You must pay royalty at the rate specified in your lease at the time when you use, sell, or otherwise finally dispose of the coal.

(e) You must allocate washed coal by attributing the washed coal to the leases from which it was extracted.

(1) If the wash plant washes coal from only one lease, the quantity of washed coal allocable to the lease is the total output of washed coal from the plant.

(2) If the wash plant washes coal from more than one lease, you must determine the tonnage of washed coal attributable to each lease by:

(i) First, calculating the input ratio of washed coal allocable to each lease by dividing the tonnage of coal input to the wash plant from each lease by the total tonnage of coal input to the wash plant from all leases.

(ii) Second, multiplying the input ratio derived under paragraph (e)(2)(i) of this section by the tonnage of total output of washed coal from the plant.

§ 1206.252 How do I calculate royalty value for coal that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract, less an applicable transportation allowance determined under §§ 1206.260 through 1206.262 and washing allowance under §§ 1206.267 through 1206.269. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant that you or your affiliate

own(s) for the generation and sale of electricity, one of the following applies:

(1) You or your affiliate sell(s) the electricity, then the value of the coal subject to this section, for royalty purposes, is the gross proceeds accruing to you for the power plant's arm's-length sales of the electricity less applicable transportation and washing deductions determined under §§ 1206.260 through 1206.262 and §§ 1206.267 through 1206.269 and, if applicable, transmission and generation deductions determined under §§ 1206.353 and 1206.354.

(2) You or your affiliate do(es) not sell the electricity at arm's-length (for example you or your affiliate deliver(s) the electricity directly to the grid), then ONRR will determine the value of the coal under § 1206.254.

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.258(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments under § 1206.253(a)(2).

(c) If you are a coal cooperative, or a member of a coal cooperative, one of the following applies:

(1) You sell or transfer coal to another member of the coal cooperative, and that member of the coal cooperative then sells the coal under an arm's-length contract, then you must value the coal under paragraph (a) of this section.

(2) You sell or transfer coal to another member of the coal cooperative, and you, the coal cooperative, or another member of the coal cooperative use the coal in a power plant for the generation and sale of electricity, then you must value the coal under paragraph (b) of this section.

(d) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

(e) The values in this section do not apply if ONRR decides to value your coal under § 1206.254.

§ 1206.253 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value, or decide your value, under § 1206.254.

(2) If ONRR directs you to use a different royalty value, you must either

pay any underpaid royalties due, plus late payment interest calculated under § 1218.202 of this chapter, or report a credit for—or request a refund of—any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration that is actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the coal. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under § 1206.254.

(c) ONRR may decide to value your coal under § 1206.254 if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor by selling your coal at a value that is unreasonably low. ONRR may consider a sales price unreasonably low if it is 10 percent less than the lowest other reasonable measures of market price, including, but not limited to, prices reported to ONRR for like-quality coal; or

(3) ONRR cannot determine if you properly valued your coal under § 1206.252 for any reason, including, but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent any contract revisions or amendments, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You

may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay in whole or in part, or in a timely manner, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide to value your coal under § 1206.254.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.254 How will ONRR determine the value of my coal for royalty purposes?

If ONRR decides to value your coal for royalty purposes under § 1206.253, or any other provision in this subpart, then ONRR will determine value by considering any information that we deem relevant, which may include, but is not limited to:

(a) The value of like-quality coal from the same mine, nearby mines, the same region, other regions, or washed in the same or nearby wash plant.

(b) Public sources of price or market information that ONRR deems reliable, including, but not limited to, the price of electricity.

(c) Information available to ONRR and information reported to us, including, but not limited to, on Form ONRR-4430.

(d) Costs of transportation or washing, if ONRR determines that they are applicable.

(e) Any other information that ONRR deems relevant regarding the particular lease operation or the salability of the coal.

§ 1206.255 What records must I keep in order to support my calculations of royalty under this subpart?

If you value your coal under this subpart, you must retain all data relevant to the determination of the royalty that you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR. You must comply with any such requirement within the time that ONRR specifies.

§ 1206.256 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place coal in marketable condition and market the coal for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.

(b) If you use gross proceeds under an arm's-length contract in order to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform in order to place the coal in marketable condition or to market the coal.

§ 1206.257 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR will not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR re-determining royalty due, under this subpart, final or binding as against the Federal government or its beneficiaries unless ONRR chooses to, in writing, formally close the audit period.

§ 1206.258 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any coal produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) for those leases;

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(3) A determination that the Assistant Secretary signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701-706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.259.

§ 1206.259 Does ONRR protect information that I provide?

(a) Certain information that you or your affiliate submit(s) to ONRR regarding royalties on coal, including deductions and allowances, may be exempt from disclosure.

(b) To the extent that applicable laws and regulations permit, ONRR will keep confidential any data that you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the

Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§ 1206.260 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off of the lease or mine as determined under § 1206.261 or § 1206.262, as applicable.

(2) You do not need ONRR's approval before reporting a transportation allowance for costs incurred.

(b) You may take a transportation allowance when:

(1) You value coal under § 1206.252;

(2) You transport the coal from a Federal lease to a sales point, which is remote from both the lease and mine; or

(3) You transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You may only claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Federal and non-Federal leases, you may not disproportionately allocate transportation costs to Federal lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Federal lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Federal lease, you must allocate transportation costs to each Federal lease, as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Federal lease production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal transported.

(5)(i) You must report your transportation costs on Form ONRR-4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per-short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per-

short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under § 1206.254 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs, including, but not limited to, transportation allowances reported to ONRR and the cost to transport coal through the same transportation system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.261 or § 1206.262 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

§ 1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(c) If you have no written contract for the arm's-length transportation of coal, then ONRR will determine your transportation allowance under

§ 1206.254. You may not use this paragraph (c) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.258(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§ 1206.262 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (j) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(4) A return on the reasonable salvage value, under paragraph (i) of this section, after you have depreciated the transportation system to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the transportation system.

(e) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

- (4) Utilities.
- (5) Materials.
- (6) Ad valorem property taxes.
- (7) Rent.
- (8) Supplies.

(9) Any other directly allocable and attributable operating expenses that you can document.

(f) Allowable maintenance expenses include the following:

- (1) Maintenance of the transportation system.
- (2) Maintenance of equipment.
- (3) Maintenance labor.
- (4) Other directly allocable and attributable maintenance expenses that you can document.

(g) 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.

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of the transportation system or the life of the reserves that the transportation system services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(2) A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for the purposes of the allowance calculation.

(3) You may depreciate a transportation system only once with or without a change in ownership.

(i)(1) To calculate a return on undepreciated capital investment, you must multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transportation allowance by the rate of return provided in paragraph (k) of this section.

(2) After you have depreciated a transportation system to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return determined under paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use 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 (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.263 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on transportation costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.264 What are my reporting requirements under a non-arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length transportation costs you or your affiliate incur(s).

(b)(1) For new non-arm's-length transportation facilities or arrangements, you must base your initial deduction on estimates of allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you must use estimates based on data for similar transportation systems.

(3) Section 1206.266 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.265 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit without interest.

(b) If you improperly net a transportation allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.266 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount that you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual transportation allowance is greater than the amount that you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

§ 1206.267 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under § 1206.252, you may take a washing allowance for the reasonable, actual costs to wash the coal. The allowance is a deduction when determining coal royalty value for the costs that you incur to wash coal.

(2) You do not need ONRR's approval before reporting a washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing.

(2) Disproportionately allocate washing costs to Federal leases. You must allocate washing costs to washed coal attributable to each Federal lease by multiplying the input ratio determined under § 1206.251(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(d) ONRR may determine your washing allowance under § 1206.254 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length washing

contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high. We may consider a washing allowance unreasonably high if it is 10 percent higher than the highest other reasonable measures of washing, including, but not limited to, washing allowances reported to ONRR and costs for coal washed in the same plant or other plants in the region; or

(3) ONRR cannot determine if you properly calculated a washing allowance under §§ 1206.267 through 1206.269 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You may only claim a washing allowance when you sell the washed coal and report and pay royalties.

§ 1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(c) If you have no written contract for the arm's-length washing of coal, then ONRR will determine your washing allowance under § 1206.254. You may not use this paragraph (c) if you or your affiliate perform(s) your own washing. If you or your affiliate perform(s) the washing, then

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.258(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§ 1206.269 How do I determine washing allowances if I do not have an arm's-length washing contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the wash plant under paragraph (j) of this section. After you have elected to use either method for a wash plant, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(4) A return on the reasonable salvage value, under paragraph (i) of this section, after you have depreciated the wash plant to its reasonable salvage value.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the wash plant.

(e) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expenses that you can document.

(f) Allowable maintenance expenses include the following:

(1) Maintenance of the wash plant.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

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

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of

the wash plant or the life of the reserves that the wash plant services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(2) A change in ownership of a wash plant will not alter the depreciation schedule that the original washer/lessee established for purposes of the allowance calculation.

(3) With or without a change in ownership, you may depreciate a wash plant only once.

(i)(1) To calculate a return on undepreciated capital investment, you must multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the washing allowance by the rate of return provided in paragraph (k) of this section.

(2) After you have depreciated a wash plant to its reasonable salvage value, you may continue to include in the allowance calculation a cost equal to the salvage value multiplied by a rate of return determined under paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the wash plant multiplied by the rate of return as determined under paragraph (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.270 What are my reporting requirements under an arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on washing costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length washing contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.271 What are my reporting requirements under a non-arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length washing costs that you or your affiliate incur(s).

(b)(1) For new non-arm's-length washing facilities or arrangements, you must base your initial deduction on estimates of allowable washing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the wash plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar wash plants.

(3) Section 1206.273 applies when you amend your report based on the actual costs.

(c) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

§ 1206.272 What interest and penalties apply if I improperly report a washing allowance?

(a)(1) If ONRR determines that you took an unauthorized washing allowance, then you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(2) If you understated your washing allowance, you may be entitled to a credit without interest.

(b) If you improperly net a washing allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.273 What reporting adjustments must I make for washing allowances?

(a) If your actual washing allowance is less than the amount that you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual washing allowance is greater than the amount that you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

■ 9. Revise subpart J to read as follows:

Subpart J—Indian Coal

1206.450 What is the purpose and scope of this subpart?

1206.451 How do I determine royalty quantity and quality?

1206.452 How do I calculate royalty value for coal that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

1206.453 How will ONRR determine if my royalty payments are correct?

1206.454 How will ONRR determine the value of my coal for royalty purposes?

1206.455 What records must I keep in order to support my calculations of royalty under this subpart?

1206.456 What are my responsibilities to place production into marketable condition and to market production?

1206.457 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

1206.458 How do I request a valuation determination?

1206.459 Does ONRR protect information that I provide?

1206.460 What general transportation allowance requirements apply to me?

1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

1206.462 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

1206.463 What are my reporting requirements under an arm's-length transportation contract?

1206.464 What are my reporting requirements under a non-arm's-length transportation contract or no written arm's-length contract?

1206.465 What interest and penalties apply if I improperly report a transportation allowance?

1206.466 What reporting adjustments must I make for transportation allowances?

1206.467 What general washing allowance requirements apply to me?

1206.468 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

1206.469 How do I determine washing allowances if I do not have an arm's-length washing contract?

1206.470 What are my reporting requirements under an arm's-length washing contract?

1206.471 What are my reporting requirements under a non-arm's-length washing contract or no written arm's-length contract?

1206.472 What interest and penalties apply if I improperly report a washing allowance?

1206.473 What reporting adjustments must I make for washing allowances?

Subpart J—Indian Coal

§ 1206.450 What is the purpose and scope of this subpart?

(a) This subpart applies to all coal produced from Indian Tribal coal leases and coal leases on land held by

individual Indian mineral owners. It explains how you, as the lessee, must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms (except leases on the Osage Indian Reservation, Osage County, Oklahoma).

(b) The terms “you” and “your” in this subpart refer to the lessee.

(c) If the regulations in this subpart are inconsistent with a(an): Federal statute; settlement agreement between the United States and a lessee resulting from administrative or judicial litigation; written agreement between the lessee and ONRR's Director establishing a method to determine the value of production from any lease that ONRR expects, at least, would approximate the value established under this subpart; or express provision of a coal lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(d) ONRR may audit and order you to adjust all royalty payments.

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

§ 1206.451 How do I determine royalty quantity and quality?

(a) You must calculate royalties based on the quantity and quality of coal at the royalty measurement point that ONRR and BLM jointly determine.

(b) You must measure coal in short tons using the methods that BLM prescribes for Indian coal leases. You must report coal quantity on appropriate forms required in 30 CFR part 1210.

(c)(1) You are not required to pay royalties on coal that you produce and add to stockpiles or inventory until you use, sell, or otherwise finally dispose of such coal.

(2) ONRR may request that BLM require you to increase your lease bond if BLM determines that stockpiles or inventory are excessive such that they increase the risk of resource degradation.

(d) You must pay royalty at the rate specified in your lease at the time when you use, sell, or otherwise finally dispose of the coal.

(e) You must allocate washed coal by attributing the washed coal to the leases from which it was extracted.

(1) If the wash plant washes coal from only one lease, the quantity of washed

coal allocable to the lease is the total output of washed coal from the plant.

(2) If the wash plant washes coal from more than one lease, you must determine the tonnage of washed coal attributable to each lease by:

(i) First, calculating the input ratio of washed coal allocable to each lease by dividing the tonnage of coal input to the wash plant from each lease by the total tonnage of coal input to the wash plant from all leases.

(ii) Second, multiplying the input ratio derived under paragraph (e)(2)(i) of this section by the tonnage of total output of washed coal from the plant.

§ 1206.452 How do I calculate royalty value for coal that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less an applicable transportation allowance determined under §§ 1206.460 through 1206.462 and washing allowance under §§ 1206.467 through 1206.469. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant that you or your affiliate own(s) for the generation and sale of electricity, one of the following applies:

(1) You or your affiliate sell(s) the electricity, then the value of the coal subject to this section, for royalty purposes, is the gross proceeds accruing to you for the power plant's arm's-length sales of the electricity less applicable transportation and washing deductions determined under §§ 1206.460 through 1206.462 and §§ 1206.467 through 1206.469 and, if applicable, transmission and generation deductions determined under §§ 1206.353 and 1206.352.

(2) You or your affiliate do(es) not sell the electricity at arm's-length (for example you or your affiliate deliver(s) the electricity directly to the grid), then ONRR will determine the value of the coal under § 1206.454.

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.458(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments under § 1206.453(a)(2).

(c) If you are a coal cooperative, or a member of a coal cooperative, one of the following applies:

(1) You sell or transfer coal to another member of the coal cooperative, and that member of the coal cooperative then sells the coal under an arm's-length contract, then you must value the coal under paragraph (a) of this section.

(2) You sell or transfer coal to another member of the coal cooperative, and you, the coal cooperative, or another member of the coal cooperative use the coal in a power plant for the generation and sale of electricity, then you must value the coal under paragraph (b) of this section.

(d) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

(e) The values in this section do not apply if ONRR decides to value your coal under § 1206.454.

§ 1206.453 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value, or decide your value, under § 1206.454.

(2) If ONRR directs you to use a different royalty value, you must either pay any underpaid royalties plus late payment interest calculated under § 1218.202 of this chapter or report a credit for, or request a refund of, any overpaid royalties.

(b) When the provisions in this subpart refer to gross proceeds, in conducting reviews and audits, ONRR will examine if your or your affiliate's contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you or your affiliate for the coal. If ONRR determines that a contract does not reflect the total consideration, ONRR may decide your value under § 1206.454.

(c) ONRR may decide to value your coal under § 1206.454, if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor by selling your coal at a value that is unreasonably low. ONRR may consider a sales price unreasonably low, if it is 10 percent less than the lowest other reasonable measures of market price, including, but not limited to, prices reported to ONRR for like-quality coal; or

(3) ONRR cannot determine if you properly valued your coal under § 1206.452 for any reason, including, but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or in a timely manner, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing, and all parties to the contract must sign the contract, contract revisions, or amendments.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may decide to value your coal under § 1206.454.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.454 How will ONRR determine the value of my coal for royalty purposes?

If ONRR decides to value your coal for royalty purposes under § 1206.454, or

any other provision in this subpart, then ONRR will determine value by considering any information that we deem relevant, which may include, but is not limited to:

(a) The value of like-quality coal from the same mine, nearby mines, same region, other regions, or washed in the same or nearby wash plant.

(b) Public sources of price or market information that ONRR deems reliable, including, but not limited to, the price of electricity.

(c) Information available to ONRR and information reported to us, including but not limited to, on Form ONRR-4430.

(d) Costs of transportation or washing, if ONRR determines they are applicable.

(e) Any other information that ONRR deems to be relevant regarding the particular lease operation or the salability of the coal.

§ 1206.455 What records must I keep in order to support my calculations of royalty under this subpart?

If you value your coal under this subpart, you must retain all data relevant to the determination of the royalty that you paid. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(a) You must show:

(1) How you calculated the royalty value, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to ONRR, the representative of the Indian lessor, the Inspector General of the Department of the Interior, or other persons authorized to receive such information. Such data may include arm's-length sales and sales quantity data for like-quality coal that you or your affiliate sold, purchased, or otherwise obtained from the same mine, nearby mines, same region, or other regions. You must comply with any such requirement within the time that ONRR specifies.

§ 1206.456 What are my responsibilities to place production into marketable condition and to market production?

(a) You must place coal in marketable condition and market the coal for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor.

(b) If you use gross proceeds under an arm's-length contract to determine royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that you normally are responsible to perform in order to place the coal in marketable condition or to market the coal.

§ 1206.457 When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Notwithstanding any provision in these regulations to the contrary, ONRR will not consider any audit, review, reconciliation, monitoring, or other like process that results in ONRR re-determining royalty due, under this subpart, final or binding as against the Federal government or its beneficiaries unless ONRR chooses to, in writing, formally close the audit period.

§ 1206.458 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any coal produced. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) for those leases;

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(3) A determination that the Assistant Secretary signs is the final action of the

Department and is subject to judicial review under 5 U.S.C. 701-706.

(d) Guidance that ONRR issues is not binding on ONRR, Tribes, individual Indian mineral owners, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.459.

§ 1206.459 Does ONRR protect information that I provide?

(a) Certain information that you or your affiliate submit(s) to ONRR regarding royalties on coal, including deductions and allowances, may be exempt from disclosure.

(b) To the extent that applicable laws and regulations permit, ONRR will keep confidential any data that you or your affiliate submit(s) that is privileged, confidential, or otherwise exempt from disclosure.

(c) You and others must submit all requests for information under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

§ 1206.460 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off of the lease or mine as determined under § 1206.461 or § 1206.462, as applicable.

(2) Before you may take any transportation allowance, you must submit a completed page 1 of the Coal Transportation Allowance Report (Form ONRR-4293), under §§ 1206.463 and

1206.464. You may claim a transportation allowance retroactively for a period of not more than three months prior to the first day of the month when ONRR receives your Form ONRR-4293.

(3) You may not use a transportation allowance that was in effect before January 1, 2017. You must use the provisions of this subpart to determine your transportation allowance.

(b) You may take a transportation allowance when:

(1) You value coal under § 1206.452;

(2) You transport the coal from an Indian lease to a sales point that is remote from both the lease and mine; or

(3) You transport the coal from an Indian lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You may only claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Indian and non-Indian leases, you may not disproportionately allocate transportation costs to Indian lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Indian lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Indian lease, you must allocate transportation costs to each Indian lease, as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Indian lease's production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal transported.

(5)(i) You must report your transportation costs on Form ONRR-4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by

dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid into a dollar-value equivalent.

(g) ONRR may determine your transportation allowance under § 1206.454 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high. We may consider a transportation allowance unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs, including, but not limited to, transportation allowances reported to ONRR and the cost to transport coal through the same transportation system; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.461 or § 1206.462 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

§ 1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(c) If you have no written contract for the arm's-length transportation of coal, then ONRR will determine your transportation allowance under § 1206.454. You may not use this paragraph (c) if you or your affiliate perform(s) your own transportation.

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.458(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§ 1206.462 How do I determine a transportation allowance if I do not have an arm's-length transportation contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or you may elect to use a cost equal to a return on the initial depreciable capital investment in the transportation system under paragraph (j) of this section. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the transportation system.

(e) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expense that you can document.

(f) Allowable maintenance expenses include the following:

(1) Maintenance of the transportation system.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

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

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of the transportation system or the life of the reserves that the transportation system services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(2) A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for the purposes of the allowance calculation.

(3) You may depreciate a transportation system only once with or without a change in ownership.

(i) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transportation allowance by the rate of return provided in paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use 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 (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.463 What are my reporting requirements under an arm's-length transportation contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an

allowance based on transportation costs you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d)(1) You must submit page 1 of the initial Form ONRR-4293 prior to, or at the same time as, you report the transportation allowance determined under an arm's-length contract on Form ONRR-4430.

(2) The initial Form ONRR-4293 is effective beginning with the production month when you are first authorized to deduct a transportation allowance and continues until the end of the calendar year, or until the termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3) After the initial period when ONRR first authorized you to deduct a transportation allowance and for succeeding periods, you must submit the entire Form ONRR-4293 by the earlier of the following:

(i) Within three months after the end of the calendar year

(ii) After the termination, modification, or amendment of the applicable contract or rate

(4) You may request to use an allowance for a longer period than that required under paragraph (d)(2) of this section.

(i) You may use that allowance beginning with the production month following the month when ONRR received your request to use the allowance for a longer period until ONRR decides whether to approve the longer period.

(ii) ONRR's decision whether or not to approve a longer period is not appealable under 30 CFR part 1290.

(iii) If ONRR does not approve the longer period, you must adjust your transportation allowance under § 1206.466.

§ 1206.464 What are my reporting requirements under a non-arm's-length transportation contract or no written arm's-length contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length transportation costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(c)(1) You must submit an initial Form ONRR-4293 prior to, or at the same time as, the transportation allowance determined under a non-arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4293 by the end of the month when the Form ONRR-4430 is due, ONRR will consider the form to be received in a timely manner. You may base the initial form on estimated costs.

(2) The initial Form ONRR-4293 is effective beginning with the production month when you are first authorized to deduct a transportation allowance and continues until the end of the calendar year or termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3)(i) At the end of the calendar year for which you submitted a Form ONRR-4293 based on estimates, you must submit another, completed Form ONRR-4293 containing the actual costs for that calendar year.

(ii) If the transportation continues, you must include on Form ONRR-4293 your estimated costs for the next calendar year.

(A) You must base the estimated transportation allowance on the actual costs for the previous reporting period plus or minus any adjustments based on your knowledge of decreases or increases that will affect the allowance.

(B) ONRR must receive Form ONRR-4293 within three months after the end of the previous calendar year.

(d)(1) For new non-arm's-length transportation facilities or arrangements, on your initial ONRR-4293 form, you must include estimates of the allowable transportation costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the transportation system as your estimate, if available. If such data is not available, you must use estimates based on data for similar transportation systems.

(e) Upon ONRR's request, you must submit all data used to prepare your ONRR-4293 form. You must provide the data within a reasonable period of time, as ONRR determines.

(f) Section 1206.466 applies when you amend your Form ONRR-4293 based on the actual costs.

§ 1206.465 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late

payment interest calculated under § 1218.202 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit without interest.

(b) If you improperly net a transportation allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.466 What reporting adjustments must I make for transportation allowances?

(a) If your actual transportation allowance is less than the amount that you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter from the date when you took the deduction to the date when you repay the difference.

(b) If the actual transportation allowance is greater than the amount that you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

§ 1206.467 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under § 1206.452, you may take a washing allowance for the reasonable, actual costs to wash coal. The allowance is a deduction when determining coal royalty value for the costs that you incur to wash coal.

(2) Before you may take any deduction, you must submit a completed page 1 of the Coal Washing Allowance Report (Form ONRR-4292), under §§ 1206.470 and 1206.471. You may claim a washing allowance retroactively for a period of not more than three months prior to the first day of the month when you have filed Form ONRR-4292 with ONRR.

(3) You may not use a washing allowance that was in effect before January 1, 2017. You must use the provisions of this subpart to determine your washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing.

(2) Disproportionately allocate washing costs to Indian leases. You must allocate washing costs to washed coal attributable to each Indian lease by multiplying the input ratio determined under § 1206.451(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid into a dollar-value equivalent.

(d) ONRR may determine your washing allowance under § 1206.454 because:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length washing contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high. We may consider a washing allowance to be unreasonably high if it is 10 percent higher than the highest other reasonable measures of washing, including, but not limited to, washing allowances reported to ONRR and costs for coal washed in the same plant or other plants in the region

(3) ONRR cannot determine if you properly calculated a washing allowance under §§ 1206.467 through 1206.469 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You may only claim a washing allowance if you sell the washed coal and report and pay royalties.

§ 1206.468 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(c) If you have no contract for the washing of coal, then ONRR will determine your transportation allowance under § 1206.454. You may not use this paragraph (c), if you or your affiliate perform(s) your own washing. If you or your affiliate perform(s) the washing, then:

(1) You must propose to ONRR a method to determine the allowance using the procedures in § 1206.458(a).

(2) You may use that method to determine your allowance until ONRR issues a determination.

§ 1206.469 How do I determine washing allowances if I do not have an arm's-length washing contract?

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

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

(1) Capital costs and operating and maintenance expenses under paragraphs (d), (e), and (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Depreciation under paragraph (h) of this section and a return on undepreciated capital investment under paragraph (i) of this section, or a cost equal to a return on the initial depreciable capital investment in the wash plant under paragraph (j) of this section. After you have elected to use either method for a wash plant, you may not later elect to change to the other alternative without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(c) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(d) Allowable capital investment costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment), which are an integral part of the wash plant.

(e) Allowable operating expenses include the following:

(1) Operations supervision and engineering.

(2) Operations labor.

(3) Fuel.

(4) Utilities.

(5) Materials.

(6) Ad valorem property taxes.

(7) Rent.

(8) Supplies.

(9) Any other directly allocable and attributable operating expenses that you can document.

(f) Allowable maintenance expenses include the following:

(1) Maintenance of the wash plant.

(2) Maintenance of equipment.

(3) Maintenance labor.

(4) Other directly allocable and attributable maintenance expenses that you can document.

(g) Overhead, directly attributable and allocable to the operation and

maintenance of the wash plant is an allowable expense. State and Federal income taxes and Indian Tribal severance taxes and other fees, including royalties, are not allowable expenses.

(h)(1) To calculate depreciation, you may elect to use either a straight-line depreciation method based on the life of the wash plant or the life of the reserves that the wash plant services, or you may elect to use a unit-of-production method. After you make an election, you may not change methods without ONRR's approval. If ONRR accepts your request to change methods, you may use your changed method beginning with the production month following the month when ONRR received your change request.

(2) A change in ownership of a wash plant will not alter the depreciation schedule that the original washer/lessee established for the purposes of the allowance calculation.

(3) With or without a change in ownership, you may depreciate a wash plant only once.

(i) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the washing allowance by the rate of return provided in paragraph (k) of this section.

(j) As an alternative to using depreciation and a return on undepreciated capital investment, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital investment in the wash plant multiplied by the rate of return as determined under paragraph (k) of this section. You may not include depreciation in your allowance.

(k) The rate of return is the industrial rate associated with Standard & Poor's BBB rating.

(1) You must use the monthly average BBB rate that Standard & Poor's publishes for the first month for which the allowance is applicable.

(2) You must re-determine the rate at the beginning of each subsequent calendar year.

§ 1206.470 What are my reporting requirements under an arm's-length washing contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on washing costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit arm's-length washing contracts, production agreements,

operating agreements, and related documents.

(c) You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(d)(1) You must file an initial Form ONRR-4292 prior to, or at the same time as, the washing allowance determined under an arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4292 by the end of the month when the Form ONRR-4430 is due, ONRR will consider the form to be received in a timely manner.

(2) The initial Form ONRR-4292 is effective beginning with the production month when you are first authorized to deduct a washing allowance and continues until the end of the calendar year, or until the termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3) After the initial period that ONRR first authorized you to deduct a washing allowance, and for succeeding periods, you must submit the entire Form ONRR-4292 by the earlier of the following:

(i) Within three months after the end of the calendar year.

(ii) After the termination, modification, or amendment of the applicable contract or rate.

(4) You may request to use an allowance for a longer period than that required under paragraph (d)(2) of this section.

(i) You may use that allowance beginning with the production month following the month when ONRR received your request to use the allowance for a longer period until ONRR decides whether to approve the longer period.

(ii) ONRR's decision whether or not to approve a longer period is not appealable under 30 CFR part 1290.

(iii) If ONRR does not approve the longer period, you must adjust your transportation allowance under § 1206.466.

§ 1206.471 What are my reporting requirements under a non-arm's-length washing contract or no written arm's-length contract?

(a) You must use a separate entry on Form ONRR-4430 to notify ONRR of an allowance based on non-arm's-length washing costs that you or your affiliate incur(s).

(b) ONRR may require you or your affiliate to submit all data used to calculate the allowance deduction. You can find recordkeeping requirements in parts 1207 and 1212 of this chapter.

(c)(1) You must submit an initial Form ONRR-4292 prior to, or at the same time as, the washing allowance determined under a non-arm's-length contract or no written arm's-length contract situation that you report on Form ONRR-4430. If ONRR receives a Form ONRR-4292 by the end of the month when the Form ONRR-4430 is due, ONRR will consider the form to be received in a timely manner. You may base the initial reporting on estimated costs.

(2) The initial Form ONRR-4292 is effective beginning with the production month when you are first authorized to deduct a washing allowance and continues until the end of the calendar year or termination, modification, or amendment of the applicable contract or rate, whichever is earlier.

(3)(i) At the end of the calendar year for which you submitted a Form ONRR-4292, you must submit another, completed Form ONRR-4292 containing the actual costs for that calendar year.

(ii) If coal washing continues, you must include on Form ONRR-4292 your estimated costs for the next calendar year.

(A) You must base the estimated coal washing allowance on the actual costs for the previous period plus or minus any adjustments based on your knowledge of decreases or increases that will affect the allowance.

(B) ONRR must receive Form ONRR-4292 within three months after the end of the previous calendar year.

(d)(1) For new non-arm's-length washing facilities or arrangements on your initial Form ONRR-4292, you must include estimates of allowable washing costs for the applicable period.

(2) You must use your or your affiliate's most recently available operations data for the wash plant as your estimate, if available. If such data is not available, you must use estimates based on data for similar wash plants.

(e) Upon ONRR's request, you must submit all data that you used to prepare your Forms ONRR-4293. You must provide the data within a reasonable period of time, as ONRR determines.

(f) Section 1206.472 applies when you amend your Form ONRR-4292 based on the actual costs.

§ 1206.472 What interest and penalties apply if I improperly report a washing allowance?

(a)(1) If ONRR determines that you took an unauthorized washing allowance, then you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(2) If you understated your washing allowance, you may be entitled to a credit without interest.

(b) If you improperly net a washing allowance against the sales value of the coal instead of reporting the allowance as a separate entry on Form ONRR-4430, ONRR may assess a civil penalty under 30 CFR part 1241.

§ 1206.473 What reporting adjustments must I make for washing allowances?

(a) If your actual washing allowance is less than the amount that you claimed on Form ONRR-4430 for each month during the allowance reporting period, you must pay additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter from the date when you took the deduction

to the date when you repay the difference.

(b) If the actual washing allowance is greater than the amount that you claimed on Form ONRR-4430 for any month during the period reported on the allowance form, you are entitled to a credit without interest.

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