



## DEPARTMENT OF THE INTERIOR

### Office of Natural Resources Revenue

#### 30 CFR Parts 1206 and 1290

[Docket No. ONRR-2025-0001; DS63636400 DRT000000.CH7000267D1113RT]

RIN 1012-AA39

### Federal Oil, Gas, and Coal Amendments

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

**ACTION:** Proposed rule.

**SUMMARY:** Consistent with Executive and Secretary’s orders, ONRR proposes to amend ONRR’s Federal oil, gas, and coal valuation regulations and to specify the standard of review for Director-level appeals. This rulemaking also proposes changes that will likely reduce cost and burden to industry and the Federal Government by simplifying regulatory requirements and ultimately incentivize production to unleash energy dominance. ONRR solicits comments on all aspects of this proposed action.

**DATES:** *Comment Period:* To ensure consideration, comments must be received at one of the addresses provided below by 11:59 pm EDT on **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**.

**ADDRESSES:** You may submit comments to ONRR using the following methods. Please reference the Regulation Identifier Number (“RIN”) for this action, “RIN 1012-AA39,” in your comment:

- *Electronically via the Federal eRulemaking Portal:* Please visit <https://www.regulations.gov>. In the Search Box, enter Docket ID “ONRR-2025-0001” and click “search” to view the publications associated with the docket folder. Locate the document with an open comment period and then click “Comment.”

Follow the instructions to submit your public comments prior to the close of the comment period.

- *Email Submissions:* Please submit your comments via email at [ONRR\\_RegulationsMailbox@onrr.gov](mailto:ONRR_RegulationsMailbox@onrr.gov) with “RIN 1012-AA39” listed in the subject line of your message. Email submissions must be received before the close of the comment period.

*Instructions:* All comments must include the agency name and docket number or RIN for this rulemaking. All comments, including any personal identifying information or confidential business information contained in a comment, will be posted without change to <https://www.regulations.gov>.

*Docket:* For access to the docket to read background documents or comments received, go to <https://www.regulations.gov> and locate the docket folder by searching the Docket ID (ONRR-2025-0001) or RIN number (RIN 1012-AA39). In accordance with 5 U.S.C. 553(b)(4), a summary of this rule may be found at <https://www.regulations.gov> under RIN 1012-AA39.

*Information Collection Data:* The Office of Management and Budget (“OMB”) maintains information on Information Collection Request (“ICR”) renewals and approvals. You may access this information at <https://www.reginfo.gov/public/do/PRASearch>. Under the “RIN” heading enter “1012-AA39” and click the “Search” button located at the bottom of the page. To view the ICR renewal or OMB approval status, click on the latest entry (based on the most recent date). On the “View ICR—OIRA Conclusion” page, check the box next to “All” to display all available ICR information provided by OMB.

**FOR FURTHER INFORMATION CONTACT:** For regulatory and procedural questions, contact Alexis Long, Regulations Supervisor, at (303) 231-3627 or by email at [Alexis.Long@onrr.gov](mailto:Alexis.Long@onrr.gov). For royalty valuation questions, contact Amy Lunt, Royalty Valuation and Regulations Program Manager, at (303) 231-3746, or by email at [Amy.Lunt@onrr.gov](mailto:Amy.Lunt@onrr.gov).

**SUPPLEMENTARY INFORMATION:**

## **I. Background & Statutory Authority**

The Federal Oil and Gas Royalty Management Act of 1982 (“FOGRMA”), the Mineral Leasing Act of 1920 (“MLA”), and the Outer Continental Shelf Lands Act of 1953 (“OCSLA”) set forth the Secretary of the Interior’s (“Secretary”) authority to value oil, gas, and coal on Federal lands for royalty computation purposes. *See* 30 U.S.C. 207(a), 226(b), and 1702 and 43 U.S.C. 1337(a). Through the authority delegated by the Secretary, ONRR is responsible for administering a royalty management system to collect, account for, verify, and disburse royalties and other revenue generated from production on Federal lands, which includes oil, gas, coal, and other energy resources. *See* Secretary’s Order (“S.O.”) 3299, sec. 5. ONRR is specifically responsible for establishing guidelines and regulations that govern how royalties are calculated and determining the monetary obligations owed to the Federal Government from companies engaged in resource extraction on Federal lands, consistent with the particular lease, Federal statutes, and applicable regulations. This process requires accounting and oversight to ensure that the royalty calculations reflect the fair value of the resources produced, thereby safeguarding public interests and maximizing revenue generated from Federal energy resources.

FOGRMA and the mineral leasing laws provide the Secretary with the authority to “prescribe such rules and regulations as . . . necessary to carry out this chapter.” 30 U.S.C. 1751(a). This proposed rule is published pursuant to the delegated authority found in various statutes and Secretary’s orders. *See* 30 U.S.C. 189 (MLA); 30 U.S.C. 1751 (FOGRMA); and 43 U.S.C. 1334 (OCSLA); *see also* S.O. 3299, sec. 5; and S.O. 3306, sec. 3-4. Because neither FOGRMA nor the mineral leasing laws provide how “value” for royalty computation purposes is determined, “value” is therefore determined within ONRR’s regulations, located at 30 CFR part 1206.

This proposed rulemaking seeks to better define and update portions of ONRR’s regulations to reflect current practices and recent industry reporting data. ONRR proposes to streamline and clarify these regulatory requirements with the goal of reducing cost and administrative burden to ONRR and industry. These objectives not only align with FOGRMA’s stated purpose but are

also consistent with the administration’s policy of unleashing America’s energy potential as set forth in Executive Order (“E.O.”) 14154 and S.O. 3418 and to reduce regulatory burden on industry as set forth in E.O. 14192. This proposed action is consistent with these policies as the downstream impact of the proposed changes could create financial incentive to industry resulting in long-term increase to production of resources from Federal lands and waters. Further discussion of the information provided by other Interior bureaus is summarized in the respective sections below and outlined in ONRR’s Preliminary Regulatory Impact Analysis (“Preliminary RIA”) accompanying this proposed rule.

## **II. Description of Proposed Amendments**

This proposed rule seeks to amend certain Federal oil, gas, and coal valuation provisions, among other changes. The proposed changes include (1) removing the default provision and all references thereto; (2) removing the misconduct definition; (3) extending the option to value gas using an index price to all Federal gas dispositions regardless of sales type; (4) updating the index-based transportation deductions based on more current data; (5) establishing that a lessee cannot report royalty values of less than zero for Federal unprocessed gas, residue gas, and Natural Gas Liquids (“NGLs”); (6) setting forth ONRR’s ability to require production of a variety of records from lessees who elect to report under an index-based valuation option; (7) redefining gathering to allow additional deductions that a lessee was previously unable to claim in a transportation allowance; (8) identifying where the specifications for marketable condition would be established for residue gas or gas plant products; (9) clarifying depreciation with respect to non-arm’s-length transactions<sup>1</sup> for Federal oil, gas, and coal; (10) amending and

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<sup>1</sup> ONRR’s regulations, at 30 CFR 1206.20, define an “arms-length contract” to mean “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.” To the contrary, a non-arm’s-length arrangement occurs when the lessee performs certain services itself, enters into a contract with an affiliate, or does not have a contract for said service. *See* 30 CFR 1206.20 (defining the term “affiliate.”); *see also* §§ 1206.116 (non-arm’s-length transportation allowance requirements for Federal oil), 1206.154 (non-arm’s-length transportation allowance requirements for Federal gas), 1206.161 (non-arm’s-length processing allowance requirements for Federal gas), 1206.259(b)(non-arm’s-length washing allowance requirements for Federal coal), and 1206.262(b)(non-arm’s-length transportation allowance requirements for Federal coal).

clarifying certain definitions; and (11) establishing the standard of review and timeliness for ONRR Director-level appeals.

*A. Reevaluated Components from the 2020 Rule*

ONRR last amended its valuation regulations in the 2016 Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Rule (“2016 Valuation Rule”). 81 FR 43338 (July 1, 2016).<sup>2</sup> The 2016 Valuation Rule added, among other things: (1) two sections in the regulations that allowed ONRR to determine value for royalty computation purposes under certain circumstances (herein referred to as “the default provision”); and (2) the addition of a lessee’s ability to elect to use an index price for non-arm’s-length transactions for Federal gas (generally referred to as an “index-based option”). ONRR’s 2016 Valuation Rule was subsequently challenged in the United States District Court for the District of Wyoming. *Cloud Peak Energy Inc. v. U.S. Dep’t of the Interior*, 559 F. Supp. 3d 1203 (D. Wyo. 2021) (vacating in part the Federal and Indian coal provisions but upholding the Federal oil and gas changes from the 2016 Valuation Rule), *affirmed by Am. Petroleum Inst. v. U.S. Dep’t of Interior*, 81 F.4th 1048 (10th Cir. 2023). Thus, the Federal oil and gas provisions adopted in the 2016 Valuation Rule remain in effect and serve as the baseline regulatory requirements with respect to the Federal oil and gas changes proposed in this rulemaking.

On January 15, 2021, ONRR published the 2020 Valuation Reform and Civil Penalty Rule (“2020 Rule”) (86 FR 4612), which sought to, among other things, (1) remove the default provision; and (2) add an option for a lessee to elect to use an index price for arm’s-length transactions for Federal gas. However, the 2020 Rule was withdrawn and therefore never went into effect. *See* 86 FR 54045, ONRR 2020 Valuation Reform and Civil Penalty Rule: Final Withdrawal Rule (“2021 Withdrawal Rule”). ONRR acknowledged in the 2021 Withdrawal Rule

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<sup>2</sup> Prior to ONRR’s publication of the 2016 Valuation Rule (proposed and final rule), ONRR also sought stakeholder feedback early in the process by publishing Advance Notices of Proposed Rulemaking on May 27, 2011 (76 FR 30878, 30881) and Notices to hold public workshops on September 9, 2011 (76 FR 55837-8).

that it would continue to consider and evaluate whether it would adopt certain provisions from the withdrawn 2020 Rule in a future rulemaking. ONRR stated that if it were to adopt certain provisions, “it will avoid the defects that permeated the rulemaking process that resulted in the 2020 Rule and which necessitate the withdrawal of that Rule.” 86 FR 54045, 54047. Moreover, consistent with case law, ONRR finds that a revised rulemaking based on “a reevaluation of which policy would be better in light of the facts” is “well within [its] discretion.” *Nat’l Ass’n of Home Builders v. EPA*, 682 F.3d 1032, 1038 (D.C. Cir. 2012) (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 514-15 (2009)). Further, “[a] change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency’s reappraisal of the costs and benefits of its programs and regulations.” *Id.* at 1043 (quoting *Motor Vehicle Mfrs. Ass’n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 59 (1983) (Rehnquist, J., concurring in part and dissenting in part)). An “agency is entitled to have second thoughts, and to sustain action which it considers in the public interest upon whatever basis more mature reflection suggests.” *Dana Corp. v. ICC*, 703 F.2d 1297, 1305 (D.C. Cir. 1983).

Additionally, an agency is entitled to give more weight to socioeconomic concerns than it may have under a different administration. *Organized Vill. of Kake v. U.S. Dep’t. of Agric.*, 795 F.3d 956, 968 (9th Cir. 2015) (en banc). ONRR has the authority to revise its regulations, consistent in large part with the policy established in the Executive and Secretary’s Orders, so long as ONRR: (1) “display[s] awareness that it *is* changing position,” (2) shows “that the new policy is permissible under the statute,” (3) “believes” the new policy is better, and (4) provides “good reasons” for the new policy. *Fox*, 556 U.S. at 515-16 (emphasis in the original). If the “new policy rests upon factual findings that contradict those which underlay its prior policy,” agencies must include “a reasoned explanation . . . for disregarding facts and circumstances that underlay . . . the prior policy.” *Id.*

After additional review following the 2021 Withdrawal Rule, ONRR proposes to adopt the index-based valuation option, as amended, and remove the default provision and associated definition of misconduct. ONRR's rationale for these two proposed changes is provided below.

#### 1. Default Provision

ONRR seeks to remove the default provision from 30 CFR part 1206, subparts C and D for Federal oil and gas, references thereto, and the associated definition of misconduct from § 1206.20.

The mineral leasing laws and lease terms provide the Secretary with the authority and discretion to establish the value of production by applying various factors and relevant information. *See* 30 U.S.C. 207, 226, 1711; and 43 U.S.C. 1337. The default provision addresses valuation when ONRR determines (1) a contract does not reflect total consideration,<sup>3</sup> (2) the gross proceeds accruing to the lessee or its affiliate under a contract do not reflect reasonable consideration due to misconduct or breach of the duty to market for the mutual benefit of the lessee and the lessor, or (3) ONRR is unable to ascertain the correct value of production due to a lessee's failure to provide documents, for example.

Consistent with the *Fox* decision, ONRR acknowledges that removing the default provision and definition of misconduct is a change from its position taken in prior rulemakings. ONRR previously adopted the default provision in the 2016 Valuation Rule, in conjunction with the misconduct definition, with the intent to increase clarity and predictability on when and how ONRR would exercise the Secretary's discretion to determine the value of production for royalty computation purposes when other valuation methods were inapplicable or unworkable. *See* 81 FR 43338, 43341. However, when ONRR added the default provision and definition of

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<sup>3</sup> "Total consideration" is addressed in ONRR's definition of "gross proceeds" at 30 CFR 1206.20, which is in part defined as "the total monies and other consideration accruing for the disposition of . . . oil, gas, residue gas, and gas plant products . . . ."

misconduct in the 2016 Valuation Rule, ONRR did not identify who within the agency would make the determination, whether that decision had to be approved, or whether it could be appealed. While this provided some flexibility in how the default provision could be applied, ONRR now acknowledges that this could likely create inconsistency in how the default provision is applied. The 2016 Valuation Rule defined “misconduct” so broadly that lessees, ONRR, and ONRR’s State and Tribal partners were left without meaningful guidance or transparency as to what might be considered misconduct to trigger use of the default provision. Since the 2016 Valuation Rule went into effect, ONRR now also acknowledges that the default provision does not address whether it is a tool of last resort or a vehicle to collect and verify royalties more efficiently. Additionally, most public comment feedback received in response to ONRR’s prior valuation rulemakings stated that the default provision language was overly broad and the definition of misconduct was a source of unnecessary ambiguity. *See* 81 FR 43338, 86 FR 4612, and 86 FR 54045.<sup>4</sup> Although the Tenth Circuit upheld ONRR’s promulgation of the default provision in the 2016 Valuation Rule, the ambiguity associated with the default provision could result in the inconsistent application of the rule and is likely a contributing factor to why ONRR has only applied the default provision in one instance since the 2016 Valuation Rule went into effect.<sup>5</sup> Moreover, the authority to determine value when necessary already exists and is permissible under FOGPMA as part of the audit process and lease terms making the regulation language redundant. 30 U.S.C. 1711(c).

For the reasons stated above and public comment feedback from prior valuation regulations, ONRR proposes to eliminate: (1) the default provision from its regulations, at §§ 1206.105 and 1206.144, (2) the several references thereto throughout 30 CFR part 1206, and (3) the definition

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<sup>4</sup> ONRR sought to remove the default provision and definition of misconduct in the 2020 Valuation Rule based on similar rationale. However, due to other procedural reasons, ONRR opted to withdraw the 2020 Valuation Rule in its entirety but stated that it may reevaluate and explore the possibility of adopting certain changes from the 2020 Valuation Rule after further evaluation at a later date. *See* 86 FR 54045, 54047; *see also* the Preliminary RIA (incorporating the discussion of alternatives).

<sup>5</sup> *See API*, 81 F.4th at 1074.

of misconduct tied to the default provision, at § 1206.20. ONRR is soliciting comments on the proposed changes, as further explained below in Section III, “Requests for Public Comment.”

## 2. Index-Based Valuation Option to Value Federal Gas and NGLs

ONRR proposes to amend §§ 1206.141-142 to (1) extend the Federal gas and Federal NGLs index-based valuation option for both processed and unprocessed gas, at the election of the lessee, to arm’s-length sales; (2) change the Federal gas index-based valuation option from the highest bidweek price to a published bidweek index price; (3) update the Federal gas index-based valuation option transportation adjustments to incorporate current data; (4) expressly state that a lessee cannot report royalty values of less than zero for Federal unprocessed gas, residue gas, and NGLs; and (5) clarify that ONRR may require records from lessees that report under the index-based valuation option.

The proposed rule allows a lessee to elect to value either residue gas under the Federal gas index-based valuation option, NGLs under the Federal NGLs index-based valuation option, or both under their respective options if the residue gas and NGLs meet the requirements for using the index-based valuation option. ONRR proposes to provide this additional option to lessees to use an average market price to value their residue gas, NGLs, or both instead of using their gross proceeds and unbundling allowances to enable more streamlined reporting. Elections under this option would be made on a lease-by-lease basis. A lessee may elect to use the index-based valuation option for production occurring after the effective date set forth in the final rule. A lessee cannot change elections to use the index-based valuation option more often than once every two years. If, after a two-year election period, a lessee changes its election to gross proceeds, that election must remain for a minimum of two years. Lessees cannot make elections retroactively.

With respect to the index-based valuation option, ONRR stated in the 2021 Withdrawal Rule that it “may reexamine the issue in the future, after it has sufficient time to review, audit, and

compare royalties received for index-based valuation of Federal gas sold at non-arm's-length and actual transaction data for Federal gas sold at arm's-length received after the reinstatement of the 2016 Valuation Rule.” 86 FR 54045, 54057. ONRR received roughly 50 public comments in response to the proposed 2021 Withdrawal Rule and the proposed 2020 Valuation Rule that noted strong support for extending the index-based valuation option to arm's-length dispositions. Some commenters agreed that extending the option to arm's-length transactions would provide certainty and clarity to pricing and would effectively reduce administrative burden on lessees. While the 2016 Valuation Rule only adopted an index option for non-arm's-length transactions, ONRR also received public comments in response to the 2016 Valuation Rule that requested ONRR implement an arm's-length option for index reporting. However, ONRR decided not to extend the option at that time. Additionally, ONRR determined that a withdrawal of the 2020 Valuation Rule was warranted, in part, because the “index-based valuation formula generally is not as reliable a measure of royalty value as is the use of actual sales prices, transportation costs, and processing costs obtained or incurred in arm's-length transactions.” 86 FR 54057. Under this proposed rule, and to overcome this issue, lessees must maintain and may be required to provide documentation of gross proceeds to ensure the index-based valuation option remains an accurate representation of value.

Based on updated data from calendar years 2020-2024, ONRR estimates \$2 million in reduced administrative costs to lessees (*see* Section III.B.1.v of the Preliminary RIA for a full assessment of administrative costs), which supports the administration's priority of minimizing regulatory burden. For calendar years 2020-2024, where the index-based valuation option for non-arm's-length sales were available to lessees, ONRR saw an adoption rate of approximately 16 percent. ONRR anticipates a higher adoption rate of the index-based valuation option under this proposed rule because: (1) the proposed rule seeks to extend the index-based valuation option to arm's-length Federal gas and NGL sales; and (2) the proposed rule changes the base price for the Federal gas index-based valuation option from *high* bidweek monthly price to the

*average* (or “midpoint”) index bidweek monthly price. The high bidweek price represents the maximum bid received for gas at a specific index location during the bid week, while the average bidweek price is a calculated midpoint or volume-weighted average of all bids for that period, providing a more representative price.

Both changes may potentially make the index-based valuation option more attractive to lessees because they provide a previously unavailable option for more streamlined reporting at a reasonable market value. While ONRR maintains that gross proceeds under an arm’s-length contract is the best indicator of value because the transaction occurs between independent parties who are both motivated by self-interest, industry has communicated its support in prior public comments for extending the index-based valuation option to arm’s-length sales. Furthermore, industry commenters previously expressed general support for using the published bidweek index price which more closely approximates their gross proceeds and may reduce administrative burden on industry. However, ONRR is soliciting public comment on its assumptions specific to the proposed changes for the index-based valuation option and whether these changes should be adopted in the final rule.

Currently, §§ 1206.141(c)(1)(i) and 1206.142(d)(1)(i) establish that the highest bidweek price is used for calculating value under the Federal gas index-based valuation option. In reevaluating this change proposed in the 2016 Valuation Rule and 2020 Rule, ONRR proposes using the published average bidweek price rather than the highest bidweek price (*see* Section III.B.2 in the Preliminary RIA). This price should more closely approximate the price many lessees likely receive as gross proceeds and would apply a universal valuation approach to unprocessed gas, residue gas, and NGLs. ONRR reconsidered its position taken in the 2016 Valuation Rule that the highest bidweek price is necessary to protect the interests of the Federal lessor. ONRR determined that, based on economic data (further discussed in the Preliminary RIA, Section III.B.2) and public comments, using the average bidweek index price would lower administrative burden and more closely approximate the price lessees would receive as gross

proceeds. Comments even called out that often gas sales prices are based on the published average index price, so making this the ONRR standard would be most in line with industry pricing. The Bureau of Land Management (“BLM”) estimates this may result in increased Federal royalty and lease bonus revenue and incentivize production on Federal lands.

More specifically, BLM anticipates ONRR’s proposed changes will reduce disputes between lessees and ONRR and enhance the attractiveness of Federal lands by providing greater certainty in fiscal obligations and simplifying compliance. Reducing administrative burden and improving the clarity and transparency of the regulatory requirements is likely to encourage more investment in Federal leases, which could lead to increased bonuses from lease competition. This efficient valuation process would provide more predictable royalty payments, enhancing the financial viability of Federal operations. Based on an estimate of a one percent increase in funding for Federal onshore oil and gas lease sales, BLM estimates a potential additional \$2.4 million annual impact on bonus bids<sup>6</sup> within one year of the final rule.

ONRR additionally proposes to adjust the transportation deductions for the Federal gas index-based valuation option found in §§ 1206.141(c)(1)(iv) and 1206.142(d)(1)(iv) to more closely align with current market conditions. The initial Federal gas index-based valuation option transportation adjustments were calculated in the 2016 Valuation Rule. ONRR proposes to adjust these values to reflect more current numbers based on recent data.

Furthermore, ONRR proposes additions to §§ 1206.141 and 1206.142 to include language that the reported value of unprocessed gas, residue gas, and NGLs may not be less than zero. The value language is updated from the proposed 2020 Rule which included “at or less than zero.” ONRR is updating this language to address when the value of gas received under a lessee’s

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<sup>6</sup> BLM’s regulations at 43 CFR 2809.14(c) generally define the term “bonus bid” to “consists of any dollar amount that a bidder wishes to bid in addition to the minimum bid.”

contract may be a negative value, and ONRR seeks to clarify that a lessee may not report a negative value in those cases but may report zero.

Finally, ONRR proposes to add language that requires a lessee to provide certain records if they report using the index-based valuation option. Because gross proceeds under an arm's-length sale is the best indicator of value, ONRR needs to access the records for certain sales to ensure that the index-based valuation option aligns with the value under arm's-length transactions for royalty purposes over time. ONRR seeks public comment on the proposed expansion of the index-based valuation option to arm's-length sales, in addition to the above-referenced modifications, as detailed further in Section III, "Requests for Public Comment," below.

## *B. Gathering Definition and Offshore Policy*

### *1. Proposed Changes to Gathering*

In 1988, the Minerals Management Service's ("MMS") promulgated its first substantive oil and gas royalty regulations, which defined gathering as "the movement of lease production to a central accumulation or treatment point." 53 FR 1184 (Jan. 15, 1988) (oil) and 53 FR 1230 (Jan. 15, 1988) (gas). At the time, companies were exploring Outer Continental Shelf ("OCS") deepwater areas (generally considered areas in water depths greater than 1,000 feet), but only minimal production had commenced. In the 1990s, industry moved heavily into the OCS deep water environment. Since that time, through experience and technological advances, industry has been producing oil and gas from deeper and harder-to-reach OCS areas. Despite these advances, the regulations defining gathering and transportation have been largely unchanged since 1988.

Moreover, since the 1988 rules went into effect, the phrase "central accumulation or treatment point" has not been further defined in the regulations. This lack of clarity has led to ongoing disputes and litigation between MMS/ONRR and lessees. *See, e.g., Nexen*, 2004 WL 722435 (E.D. La. 2004); *Kerr-McGee Corp.*, 147 IBLA 277 (1999); *DCOR, LLC v. United*

*States Dep't of the Interior*, No. 3:21-CV-00120-N, 2023 WL 8628322 (N.D. Tex. Dec. 13, 2023) (upholding in part and remanding part ONRR's Director Decision in *DCOR, LLC*, ONRR-17-0074-OCS, 2019 WL 6127405 (Aug. 26, 2019)). In each of these disputes, and in others that ONRR encounters through its audit program, lessees have interpreted the phrase, "central accumulation or treatment point," to allow the lessee to deduct a larger transportation allowance from its royalties owed as compared to what ONRR may permit based on its interpretation of the same phrase. As a result, ONRR seeks to amend the definition of gathering in this proposed rule by clearly identifying the locations at which gathering ends and where transportation begins to resolve this issue.

i. Onshore Gathering

For Federal onshore, non-OCS leases, ONRR proposes to amend 30 CFR 1206.20 to define gathering as the movement of production from the wellhead to the BLM-approved measurement point. This is the location where the lessee has met BLM's operational requirements for royalty measurement and, typically, the point at which a purchaser or transporter accepts oil or gas from the lessee. BLM generally refers to this as the Facility Measurement Point. By clearly articulating the BLM-approved measurement point in the regulations, it clarifies the point at which onshore gathering ends. This change does not impact the current interpretation of gathering for onshore leases and maintains the same effective definition for gathering as onshore Indian leases, ensuring conformity between BLM and the Bureau of Indian Affairs ("BIA") leases.

ii. Offshore Gathering

OCS leases differ from onshore leases in several ways. Production occurs in water rather than on land. The subsea environment is harsh – with high pressures and cold temperatures. Also, offshore production must be moved to shore where the markets are located. Because of these physical differences, the Bureau of Safety and Environmental Enforcement ("BSEE") may

approve measurement points that are many miles away from the lease. Additionally, BSEE may approve royalty meters at different locations based on the type of production. More specifically, BSEE may approve a gas royalty meter on an offshore platform but may approve an oil or condensate royalty meter for the same lease at an onshore location. For these reasons, using the BSEE-approved measurement point to designate the end of gathering and the beginning of transportation does not provide the same clarity as using the BLM-approved measurement point for onshore leases.

Furthermore, BSEE may approve several measurement locations for different lease products such as gas, oil, drip condensate, and flash gas. Some measurement locations are on the first platform at which production surfaces, some are on secondary platforms, and some are onshore. When ONRR uses those measurement locations to designate the end of gathering and the beginning of transportation, it introduces unnecessary complexity and administrative burden. Before calculating its allowance, a lessee must identify the measurement location for each royalty-bearing product, of which there are at least two and as many as six or seven. When a lease has multiple measurement points, the lessee must perform separate transportation allowances for each product. This is also burdensome for ONRR to verify. It also creates a confusing situation where, if using the BSEE-approved measurement points for each product as the point where gathering ends, the movement of one product to shore is considered transportation but the movement of other product to shore is gathering.

Another added complexity for offshore production exists as BSEE regularly approves off-lease measurement, whereas BLM rarely does. This creates situations where OCS lessees, particularly those in deepwater, may move production as far as 60 miles before the production is measured for royalty purposes. Defining this movement as gathering, which the current regulations do, is different than the on-lease gathering (usually less than one mile) that occurs for onshore lessees before the BLM-approved measurement point.

There are also differences related to how production is transported to downstream markets. Onshore, transportation equipment can easily be placed on the well pad and gas rarely leaves the lease exceeding the marketable condition requirements, while offshore, platforms house equipment that supports the transportation of production to shore, and, especially in deepwater, production regularly exceeds the marketable condition requirements. Platform equipment regularly compresses, dehydrates, or otherwise conditions gas beyond the marketable condition requirements, the costs of which ONRR would generally allow lessees to include in a transportation allowance under § 1206.153(b)(9). However, because this equipment is physically located upstream of the BSEE-approved royalty measurement point, under the current regulations, these costs are disallowed as gathering costs.

ONRR therefore proposes a separate definition for OCS production to account for these differences and additional complexities. ONRR proposes to revise the definition of gathering for OCS leases at § 1206.20 as the movement of production from the well to the closest of (1) a point of accumulation of one or more wells; (2) the point at which production is separated; or (3) the boundary of the lease. The proposed revision to the definition of OCS gathering would more closely match the convention used onshore, where gas and oil are generally measured and separated within the boundary of the lease itself, which would provide more consistency for the regulated entities.

Lastly, ONRR proposes to remove the language “For oil produced on the OCS, the movement of oil from the wellhead to the first platform is not transportation” from the oil and gas transportation allowance regulations (§§ 1206.110 and 1206.152, respectively). ONRR’s proposal to amend the definition of gathering explained above renders this language moot.

## 2. Clarifying Additional Allowable Transportation Costs

ONRR’s regulations currently provide that a lessee can deduct certain “reasonable, actual costs” costs from its royalty value as a transportation allowance. *See* §§ 1206.110 and 1206.152.

Through this proposed rule, ONRR proposes to specify that flow assurance costs related to transportation of production and other pipeline maintenance costs explained below would be an allowable cost a lessee can deduct under ONRR's transportation allowance regulations.

Flow assurance for oil and gas pipelines includes, but is not limited to, physical or chemical processes related to ensuring production can flow through a pipeline without blockages forming from paraffin or hydrates. This change would include: (1) heated flowlines; (2) equipment such as pipeline pigs and associated pig launchers and receivers; and (3) chemicals that prevent blockages in a pipeline such as hydrate inhibitors or paraffin inhibitors. This addition will clarify certain pipeline maintenance costs, specifically costs related to flow assurance and pipeline remediation, may be included in a transportation allowance. ONRR is distinguishing the prior mentioned maintenance costs from the costs associated with injecting chemicals within the wellbore, because the chemicals in this situation would be required for production purposes. Therefore, ONRR would not allow these costs to be included in a transportation allowance. This proposed rule also clarifies that a lessee may deduct its reasonable, actual costs for repairing, replacing, or restoring operability of a plugged or damaged pipeline. If a lessee receives insurance compensation for these costs, the lessee must reduce its allowance by the compensation it receives.

While these categories mainly apply to OCS subsea movement, they may also apply to certain onshore lessees. Therefore, ONRR did not restrict these costs to OCS production only. ONRR proposes to address these categories by adding language to the arm's-length transportation allowance regulations and the non-arm's-length transportation allowance regulations. *See* §§ 1206.111-112 (oil) and §§ 1206.153-154 (gas).

ONRR's proposed changes clarify and affirm that flow assurance costs are costs that support transportation. This change promotes clarity and certainty by clearly stating these costs are transportation costs and may be included in a transportation allowance. In reducing the

uncertainty of whether a cost may be included in an allowance, ONRR intends to reduce administrative burden for lessees by minimizing confusion surrounding deductions for these costs. In clearly specifying these costs, ONRR is creating more transparency for a lessee to know which costs it may include in its transportation allowance calculations, resulting in more accurate reporting. ONRR anticipates this will streamline ONRR audit and compliance activities, consistent with the requirements to ensure accurate and timely reporting under FOGRMA.

### 3. Deepwater Platform Equipment

Platform equipment is generally owned by the lessee, so the lessee must calculate their allowance under the non-arm's-length regulations. ONRR's regulations allow the lessee to deduct "capital investment costs . . . for depreciable fixed assets . . . that are an integral part of the transportation system." §§ 1206.112(e) and 1206.154(e). As a result of ONRR's proposed change to the definition of gathering for OCS leases, certain platform equipment costs would be eligible for a transportation allowance that were previously considered gathering costs. Through this proposed rule, ONRR seeks to specify and delineate in the regulations which OCS platform costs are integral to transportation and may therefore be included in a transportation allowance.

Prior to January 1, 2017, the regulations and the MMS Memorandum, entitled "Guidance for Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters," dated May 20, 1999 ("Deepwater Policy"), did not define which platform expenses were considered an "integral part of the transportation system." This ambiguity led to frequent disputes between ONRR and lessees, whereby lessees and ONRR disagreed as to whether certain platform equipment costs were "integral" to the transportation system.

ONRR proposes to amend its regulations to better define costs it considers to be integral to transportation, thereby clarifying what is an allowable transportation deduction. ONRR proposes to add language to specify that this includes platform costs related to flow assurance. Under the proposed changes for oil, a lessee may deduct the costs associated with pumps used to deliver oil

into the export pipeline leaving the platform. For gas, ONRR's proposed changes would allow a lessee to deduct the costs associated with the compression, dehydration, and treatment of gas to the extent that those services are required for transportation and exceed the services necessary to place production into marketable condition. This equipment requires space on the platform; and platform space has associated costs of designing and building the platform to accommodate all the needed equipment. Accordingly, the proposed rule allows lessees to deduct platform costs directly allocable to the space needed to house the allowed equipment, including equipment that conditions gas beyond the marketable condition requirements. Generally, platform space costs are allocated based on the square footage required for the allowed pieces of equipment.

Further, ONRR proposes to amend its regulations by adding the term, "directly allocable" to describe which costs for allowed equipment may be included in the allowance. *See* proposed §§ 1206.111(b)(13), 1206.112(c)(6), 1206.153(b)(13), and 1206.154(c). "Directly allocable" costs have a clear connection to the allowed transportation equipment and can be accurately quantified. For example, a piece of equipment will generally have clear costs of fabrication or purchase as well as delivery and installation. Additionally, most platforms track the usage of electricity by various pieces of equipment and will be able to quantify the amount of electricity used to power that compressor. This is one example of a directly allocable cost that a lessee may deduct. However, platform costs associated with lighting, the helipad, or living quarters, for example, do not have a clear connection to transportation nor is there a clear cost associated with transportation. These types of platform costs may not be included in the transportation allowance.

For floating platforms on the OCS, a lessee may also deduct costs directly allocable to the buoyancy needed to support the additional weight of the allowed transportation equipment. A lessee must use a reasonable method to calculate and allocate these costs and, when requested, provide documentation supporting its calculations and allocation methods. Generally, buoyancy costs are allocated based on the weight of the equipment.

In addition to transportation-related equipment, OCS platforms contain equipment that is required for reasons other than transportation such as production operations, human safety, environmental protection, drilling operations, and other non-transportation related purposes. A lessee may only deduct the specific transportation-related platform costs listed in the proposed regulation.

#### 4. Distinction Between this Proposed Rule and the Deepwater Section in the 2020 Rule

ONRR acknowledges it has modified its prior position with respect to gathering and allowances. ONRR previously rescinded the Deepwater Policy as part of the 2016 Valuation Rule. 81 FR 43340. The Deepwater Policy allowed lessees to deduct certain costs associated with moving bulk production from the seafloor to the first platform in water depths greater than 200 meters. When rescinding the Deepwater Policy through the 2016 Valuation Rule, ONRR stated the Deepwater Policy had served its purpose and was no longer needed because “[t]he regulations still allow offshore lessees to deduct considerable transportation costs to move oil and gas from the offshore platform to onshore markets.” *Id.* ONRR stated that rescinding the policy would better clarify the meaning of gathering. Further, when the Tenth Circuit upheld ONRR’s rationale for rescinding the Deepwater Policy in the 2016 Valuation Rule, it acknowledged that ONRR “had the power to reclassify those costs under its broad statutory authority to define ‘the value of production’ for royalty purposes . . . .” *API*, 81 F.4th 1048, 1061.

In the now withdrawn 2020 Rule, ONRR sought to allow a deduction of certain deepwater gathering costs by creating an exception to the gathering rule when certain conditions were met.<sup>7</sup> The 2020 Rule provisions only applied to certain deepwater movement, and not to all deepwater movement or other areas such as shallow water properties in the Gulf of America, offshore Pacific properties off the coast of California, or remote Alaska properties. However, upon

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<sup>7</sup> See the 2020 Rule at 86 FR 4622 and the 2020 Proposed Rule, at 85 FR 62054, for a discussion of ONRR’s regulatory history with respect to offshore policy, the definition of gathering, and the Deepwater Policy.

reevaluating this component of the 2020 Rule, ONRR determined that these provisions did not simplify the regulations and instead added more unintended complexity. Specifically, the 2020 Rule's attempted changes would have required lessees to review multiple factors to determine whether exceptions to the gathering requirement applied—such as water depth, adjacency requirements between the producing block and the block on which the platform was located, and the operational design of the subsea development. ONRR would subsequently be required to verify all this information when conducting compliance activities.

Additionally, the 2020 Rule did not specify which costs may be included in a transportation allowance. In addition to pipeline costs, platform costs are a significant part of a lessee's total cost of transportation on the OCS. However, platforms serve a variety of purposes, some related to transportation and some not. Thus, these ambiguities from the related provisions in the withdrawn 2020 Rule not only would have increased burden to both lessees and ONRR but could have also likely led to additional confusion and resulting appeals and litigation.

Through this proposed rule, ONRR intends to better define the location at which gathering ends and transportation begins. ONRR also intends to specify which platform costs, flow assurance costs, and pipeline remediation costs may be included in a transportation allowance. ONRR believes the proposed changes addressed herein serve as a better option than previous attempts to address OCS gathering costs.

ONRR recognizes that past rulemakings have stated that the cost of placing production into marketable condition must occur at no cost to the Federal lessor and defined the movement of bulk oil and gas production that has not been separated, treated, and measured for royalty purposes as gathering since those processes are integral to placing production in marketable condition. *See* 53 FR 1190-1191 and 86 FR 54050. The proposed change to the definition of gathering for OCS leases does not modify ONRR's interpretation of marketable condition costs but simply serves to rectify an inconsistency between onshore and OCS leases by allowing a

transportation deduction for movement of production beyond the lease boundary or a nearby, on-lease location. For onshore leases, separation, treatment, and measurement of oil generally occur on the lease itself, and all movement beyond that point is transportation. The proposed definition of gathering for OCS leases more closely aligns onshore and OCS gathering. Under the proposed rule, the marketable condition processes of compression, dehydration, separation, treatment, etc. continue to be disallowed costs when calculating a transportation allowance. Thus, ONRR's proposed changes to its regulations are improvements to better delineate these regulatory requirements, which are permissible under FOGRMA's intended purpose to ensure timely and accurate reporting and payment of royalties owed on production.

Moreover, based on data provided by the Bureau of Ocean Energy Management ("BOEM"), the proposed changes could benefit OCS lessees in the form of clarity, certainty, and cost savings in the calculation and payment of royalties. Through the estimated increase in deductions, and resulting decrease to royalty payments, BOEM anticipates the monies retained by industry could encourage lessees to reinvest in oil and gas production and infrastructure on the OCS. BOEM's analysis allocates a portion of the retained royalty payments to shareholders, taxes, and other financial obligations, with the majority, \$205 million per year, retained by industry to potentially reinvest in the Gulf of America OCS. Specifically, BOEM estimates a potential increase in production of 2.60 million barrels per year during calendar years 2031 through 2046. The estimated average annual increase in gross royalties for this additional production is \$30.4 million for the same period. BOEM's estimated incremental production is valued using a flat oil price of \$70 per barrel and a royalty rate of 16.67%. For additional information on the impact to future investment and production, please refer to the Preliminary RIA.

As specified below in Section III, "Requests for Public Comment," ONRR invites public comment on these proposed changes to the definition of gathering and the associated amendments to the transportation allowance regulations, including comments on any alternatives ONRR should consider.

### *C. Clarifying Marketable Condition*

ONRR proposes to add § 1206.146(c) to identify where the specifications for marketable condition would be established for residue gas or gas plant products. ONRR's current regulations define marketable condition at § 1206.20 as "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." ONRR is not proposing changes to the definition of marketable condition but proposes to add § 1206.146(c) to clarify where gas is marketable under a sales contract typical for a field or area. The new paragraph § 1206.146(c) would codify ONRR's current practice and provide upfront transparency of what standards a lessee should use to evaluate its marketable condition requirements.

Marketable condition is the quality standard that residue gas and gas plant products must meet to be accepted by the purchaser. These quality requirements often include limits on the amount of acid gases, water vapor, or other impurities allowed, as well as a minimum pressure required for the residue gas and gas plant products to be delivered. Pursuant to § 1206.146(a), a lessee is required to place its production into marketable condition at no cost to the Federal lessor. The addition of paragraph (c) would add transparency and clarity to the location where gas needs to meet the quality standards for sale to commercial markets while retaining consistency with ONRR's established interpretation of the requirement.

Proposed § 1206.146(c)(1) would codify, consistent with ONRR's existing practice, that when a lessee, or a service provider on behalf of a lessee, delivers residue gas or gas plant products to a mainline pipeline, then a lessee's marketable condition would be set by the required delivery specifications for that pipeline. This paragraph identifies where ONRR has historically considered gas to be marketable based on the condition and access to markets. A mainline pipeline is typically the high-pressure pipeline that a processing facility delivers gas to after processing and that transports gas to its sales market. Mainline pipelines are often interstate

pipelines, which are Federal Energy Regulatory Commission (“FERC”) regulated, and the publicly available tariff for a pipeline specifies the gas quality requirements for that pipeline. The tariff may not define the minimum pressure. The minimum pressure requirement is the pressure which the mainline pipeline accepts delivery of residue gas or gas plant products.

For residue gas or gas plant products that are delivered to market through means other than a mainline pipeline, § 1206.146(c)(2) proposes that marketable condition would be established as the condition required by the transporter to market or purchaser. This may include gas plant products that are sold directly to a purchaser or are transported by other means (e.g. truck, rail, etc.) at the outlet of a processing plant. Marketable condition requirements would be the quality specifications outlined in either a purchase agreement or required by the transporter to market.

For situations where a lessee’s gas is never processed by the lessee or purchaser on behalf of the lessee, and a lessee can reasonably demonstrate that there is a market at an alternative location for the unprocessed gas, then the lessee would be able to use an alternative location for marketable condition under proposed § 1206.146(c)(3). This paragraph would clarify marketable condition requirements where there is a competitive market for unprocessed gas near the lease. A lessee would need to reasonably support that a competitive market exists for the unprocessed gas at an alternative location. For example, if a lessee has documentation of competing offers from different purchasers for the unprocessed gas near the lease and in its current condition that documentation could be used to support that a market exists near the lease. Simply selling lesser quality gas to any willing buyer would not satisfy a lessee’s duty to market. For gas that is marketable at an alternative location, marketable condition is the specifications either required or accepted by the purchaser at the alternative delivery point.

ONRR’s current regulations do not specify a location where quality standards are used to establish marketable condition requirements. However, through this proposed rule, ONRR seeks to incorporate the proposed language to align with ONRR’s historical interpretation and practice.

In addition to the proposed regulations representing longstanding practice and interpretation, numerous courts have upheld and applied those interpretations. *See, e.g. R.E. Yarbrough Co.*, 122 IBLA 217, 221 (1993); *Amoco Prod. Co. v. Watson*, 410 F.3d 722, 725 (D.C. Cir. 2005); *Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008); *J-W Operating Co.*, 159 IBLA 1 (2003). This proposed regulation helps to resolve uncertainty of interpreting where gas is in marketable condition.

#### *D. Non-Arm's-Length Allowances Including Depreciation*

Currently, a lessee may include costs of services, such as transportation, processing for gas, and washing for coal, in an allowance. In many situations, a lessee does not have an arm's-length contract for these services. Instead, it provides such services for itself or contracts with an affiliate, which ONRR considers a non-arm's-length arrangement.

In non-arm's-length allowance situations, ONRR's regulations allow a lessee to include the capital costs of transportation, processing, or washing assets in a non-arm's-length allowance. Under the current non-arm's-length allowance regulations at §§ 1206.112, 1206.154, 1206.161, 1206.259, and 1206.262), a lessee may claim an allowance for capital costs by calculating either depreciation and a return on the undepreciated capital cost of a fixed asset or a return on the initial capital cost.

##### 1. Acquired Assets

Under the current regulations, when a lessee acquires ownership of a transportation, processing, or washing system from another lessee, the regulations at §§ 1206.112(i)(1)(i), 1206.154(i)(1)(i), 1206.161(h)(1)(i), 1206.259(b)(2)(iv)(A), and 1206.262(b)(2)(iv)(A) provide that the acquisition will “not alter the depreciation schedule that the original . . . lessee established for purposes of the allowance calculation.” When the acquiring lessee either does not have access to the depreciation schedule prepared and used by the original owner or when the original depreciation schedule does not comply with the regulations in §§ 1206.112, 1206.154, 1206.161, 1206.259, or 1206.262, the acquiring lessee may be denied the opportunity to include

the cost of those acquired assets in an allowance. The current regulations also do not explicitly allow a lessee to claim the capital costs of an acquired asset or system in a non-arm's-length allowance.

ONRR proposes to modify the regulations at §§ 1206.112(i), 1206.154(i), 1206.161(h), 1206.259(b)(2)(v), and 1206.262(b)(2)(v) so that lessees may include the allowable capital costs associated with such acquired assets in a non-arm's-length allowance. For example, if a lessee acquired an existing gas pipeline that it uses to transport Federal gas and has a compliant depreciation schedule from said acquisition, this proposed rule will require the lessee to use the compliant schedule when calculating a transportation allowance for royalty reporting. If a lessee does not have a compliant depreciation schedule, the lessee could propose a depreciation schedule for the gas pipeline to ONRR. ONRR will review the lessee's proposal for reasonableness and consistency with a lessee's own policies and reporting, standard industry practices, and other factors that are listed in the relevant sections of the proposed rule. If ONRR approves the proposed depreciation schedule, it will replace any missing or non-compliant depreciation schedules, thus enabling the lessee to claim allowances for its acquired capital costs. If ONRR determines the proposed schedule is inaccurate or insufficient, the lessee must correct its royalty reporting on the Form ONRR-2014 within 30 days, consistent with § 1210.30, and pay any late payment interest owed.

## 2. Alternative In-Service Date

Although the proposed rule includes a path to claim depreciation for acquired assets, after the publication of a final rule, a lessee may still not be able to recoup the full value of the royalty share of capital costs as part of a non-arm's-length allowance. For example, under the proposed rule, a lessee may propose a depreciation schedule to ONRR. Should ONRR approve, the lessee may not be able to amend the reporting that corresponds to the approved depreciation schedule, and this time limitation effectively prevents the lessee from claiming the full amount of the royalty share of capital costs. Moreover, if the regulatory changes in this proposed rule become

final, and ONRR allows the costs associated with a piece of equipment that was previously disallowed, a lessee may be able to realize the full economic benefit of that piece of equipment. Therefore, the addition of the alternative in-service date for depreciation is necessary for lessees to apply the proposed regulations for transportation allowances. To address this issue and allow a lessee the ability to recover the full capital cost of transportation, processing, and washing systems, ONRR proposes to allow a lessee to select an alternative in-service date. The alternative in-service date may only be claimed in situations where a fixed asset has not previously been included in a depreciation expense or a return on initial investment. The alternative in-service date does not change the total amount of depreciation or return that may be claimed in an allowance, but rather shifts the applicable depreciation window forward, thus providing a lessee the opportunity to claim the full royalty share of the capital cost in a non-arm's-length allowance.

### 3. Proposed Definitions

ONRR's current regulations do not precisely define many terms that a lessee would use to calculate a non-arm's-length allowance. This proposed method for depreciation of previously undepreciated assets necessitates adding and clarifying definitions for terms in the alternative service date and depreciation schedule provisions outlined above. The new definitions provide clarity and certainty for lessees when determining non-arm's-length allowances. ONRR anticipates that the consistent application of accounting terms will also reduce the administrative burden on industry of complying with ONRR's regulations. Additionally, the proposed definitions will likely ensure consistency between lessees that may interpret and apply ONRR's current regulations differently. Thus, ONRR developed definitions that incorporate concepts from how industry commonly interprets and applies such terms; ONRR's interpretation of the application of the current regulations in §§ 1206.112, 1206.154, 1206.161, 1206.259, and 1206.262; accounting principles generally accepted in the United States; and other expert sources. Since the additional definitions align with existing interpretation and practices, ONRR

expects that lessees will not need to substantially change their accounting and reporting processes for non-arm's-length allowances.

Through this proposed rule, ONRR seeks to add the following definitions in § 1206.20 for oil and gas and § 1206.251 for coal:

Proposed Definition	Comment
<p><b>Actual cost</b> means a cost incurred by a lessee. Actual costs do not include imputed costs, theoretical costs, or avoided costs.</p>	<p>The current regulations make references to <b>Actual cost</b> in multiple places, but do not define it. Providing a definition for <b>Actual cost</b> allows a lessee to standardize reporting and reduce the compliance costs of royalty reporting by including in an allowance only those costs that will be supported by the definition.</p>
<p><b>Alternative in-service date</b> means the date selected under §§ 1206.112(i)(1)(i), 1206.154(i)(1)(i), 1206.161(h)(1)(i), 1206.259(b)(2)(v)(B)(1), or 1206.262(b)(2)(v)(B)(1) from which the lessee will apply its depreciation schedule in calculating a non-arm's-length allowance. The term "alternative in-service date" has no meaning outside of the commodities and regulations mentioned.</p>	<p>The proposed regulations add the option for a lessee to propose an alternative in-service date for fixed assets in certain circumstances. This definition identifies the location of the regulations governing this option and clarifies that the option is only available for royalty reporting of Federal oil, Federal gas, and Federal coal.</p> <p>This definition also supports the expanded definition of <b>Gathering</b> for production from OCS leases in 30 CFR 1206.20 should a lessee elect to propose an alternative in-serve date for transportation assets regarded as gathering under the current regulations.</p>
<p><b>Capital cost</b> means the actual cost associated with the initial purchase or construction of a fixed asset with a useful life greater than one year. Actual costs incurred to improve a fixed asset, enhance or modify a fixed asset's functionality, or extend the useful life of a fixed asset are also capital costs when the economic benefits of the changes extend beyond one year. Capital costs include those costs reasonable and necessary to bring the fixed asset to the condition and location of its intended use, such as shipping, delivery, and installation cost. The capital cost of a fixed asset reflects its value when measured at the in-service date.</p>	<p>The current regulations provide a general description of capital cost, but do not precisely define it. Providing a definition for <b>Capital cost</b> allows a lessee to standardize reporting and identify what documentation will be required under audit. This clarity reduces the administrative and compliance costs of royalty reporting.</p> <p>Additionally, the definition of capital cost expands the scope of covered assets to include costs for improvements to a fixed asset that may be included in a non-arm's-length allowance, such as those for non-routine overhaul and maintenance. This expanded scope supports the proposed inclusion of <b>Costs to repair, replace or restore operability of a plugged or damaged pipeline</b> referenced in §§ 1206.111(b)(14) and 1206.153(b)(14).</p>

<p><b>Depreciation</b> means the systematic and rational allocation of the capital cost less a reasonable salvage value of a fixed asset to expense during periods when economic benefits are available to obtain from the fixed asset. Depreciation begins at the in-service date.</p>	<p>The current regulations make references to <b>Depreciation</b> in multiple places, but do not define it. Providing a definition for <b>Depreciation</b> allows a lessee to standardize reporting and reduce the compliance costs of royalty reporting by calculating depreciation expense in a manner that will be supported by the definition.</p> <p>Additionally, the definition supports both the option for a lessee to select an <b>Alternative in-service date</b> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>
<p><b>Depreciation schedule</b> means a document used to record and track depreciation for a fixed asset. A depreciation schedule includes a list of fixed assets that can be separately identified. Each fixed asset entry must include the capital cost, the in-service date, the method of depreciation elected, the salvage value, and either the useful life, units of production, or life of reserve. For fixed assets depreciated as a group, the depreciation schedule shall demonstrate, or allow for the calculation of, either the group’s useful life, units of production, or life of the reserve. The depreciation schedule includes, or allows for the calculation of, depreciation expense during the reporting period and the undepreciated capital cost.</p>	<p>The current regulations make references to a <b>Depreciation schedule</b>, but do not define it. Providing a definition for <b>Depreciation schedule</b> allows a lessee to standardize reporting and identify what documentation will be required under audit. This clarity reduces the administrative and compliance costs of royalty reporting.</p> <p>In addition, the proposed regulations explicitly allow for a lessee to select a depreciation method for individual assets or groups of assets. The proposed definition of <b>Depreciation schedule</b> supports this clarification and provides instruction on how a lessee must support its choice of a method of depreciation for groups of assets.</p> <p>Lastly, the definition supports both the option for a lessee to select an <b>Alternative in-service date</b> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>
<p><b>First-of-month convention</b> means that depreciation begins on the first day of the month of the in-service date or alternative in-service date.</p>	<p>The current regulations do not clarify how depreciation should be calculated when a fixed asset is placed in service during the middle of a reporting month. This definition clarifies how a lessee must calculate depreciation expense in a manner that will be supported by the definition. The <b>First-of-month convention</b> was selected to be consistent with common industry practice in order to minimize compliance costs.</p>
<p><b>Fixed assets</b> means tangible assets owned or controlled by a lessee that are used to produce or provide goods and services in the primary business activities of that entity.</p>	<p>The current regulations provide a general description of which assets may be included in an allowance, but do not precisely define it. Providing a definition for <b>Fixed assets</b> allows a</p>

<p>Fixed assets have a useful life greater than one year.</p>	<p>lessee to standardize reporting and identify what documentation could be used to support an allowance.</p> <p>The definition of <b>Fixed assets</b> expands on the definition in the current regulation by explicitly including capitalized right-of-use assets and financing leases that may be controlled by a lessee.</p>
<p><b>In-service date</b> means the earlier of the date when a fixed asset is placed in service or the date when a fixed asset is functionally ready and available for its intended use. When considering a group of fixed assets, the group in-service date is the in-service date for the primary functional fixed asset of the group.</p>	<p>The current regulations do not define when <b>Depreciation</b> should begin but rather rely on a lessee’s or an auditor’s interpretation. Providing a definition for <b>In-service date</b> allows a lessee to standardize reporting and reduce the compliance costs of royalty reporting by calculating depreciation expense in a manner that will be supported by the definition.</p> <p>Additionally, <b>In-service date</b> supports the definition of <b>Alternative in-service date</b> and a lessee’s option to claim the capital cost of an allowable in-service asset in an allowance.</p>
<p><b>Life of the reserve</b> means the estimated term over which the natural reserve provides an economic benefit. A life of the reserve estimate is based on a report from an unaffiliated or independent expert and clearly identifies the assumptions supporting the estimate. If a fixed asset services multiple reserves, the life of the reserve represents the average of the individual reserve life estimates. Life of the reserve is measured in, or is convertible into, months and is determined at or prior to the in-service date.</p>	<p>The current regulations make references to <b>Life of the reserve</b> in multiple places, but do not define it. Providing a definition for <b>Life of the reserve</b> allows a lessee to standardize reporting and identify what documentation will be required under audit. This clarity reduces the administrative and compliance costs of royalty reporting.</p> <p>Additionally, <b>Life of the reserve</b> clarifies how to calculate depreciation expense when a fixed asset or group of fixed assets service multiple reserves.</p>
<p><b>Operating Expense</b> means costs associated with the production or provision of goods and services by a business. Operating expenses are costs necessary for the company’s normal, core business activities.</p>	<p>The current regulations make references to <b>Operating expense</b> in multiple places, but do not define it. Providing a definition for <b>Operating expense</b> allows a lessee to standardize reporting and reduce the compliance costs of royalty reporting by including only those costs that will be supported by the definition in an allowance.</p> <p>The specific list of allowable operating expenses in the current regulations remains, and this definition provides a universal description that can be used to address expenses not explicitly included in the regulation’s list of allowable operating expenses.</p>
<p><b>Overhead</b> means the indirect costs of producing or providing goods and services.</p>	<p>The current regulations make references to <b>Overhead</b> in multiple places, but do not define it.</p>

<p>Overhead must be systematically and rationally allocated to the goods or services being produced or provided. Overhead is a cost necessary for the company’s normal, core business activities.</p>	<p>Providing a definition for <b>Overhead</b> allows a lessee to standardize reporting and reduce the compliance costs of royalty reporting by including only those costs that will be supported by the definition in an allowance.</p>
<p><b>Reserve</b> means the estimated quantity of known accumulations of a natural resource anticipated to be commercially recoverable from a defined area under existing economic conditions and by established operating practices from a given date forward.</p>	<p>The current regulations make references to <b>Reserve</b> through the <b>Life of the reserve</b>, but do not define it. Providing a definition for <b>Life of the reserve</b> allows a lessee to standardize reporting and identify what documentation will be required under audit. This clarity reduces the administrative and compliance costs of royalty reporting.</p>
<p><b>Salvage value</b> means the value net of disposal costs that the payor expects to realize at the end of the useful life of an asset. Salvage values are designed to minimize any gain or loss at the time of disposal. Salvage value is greater than or equal to zero. Salvage value is determined at or prior to the in-service date.</p>	<p>The current regulations make references to <b>Salvage value</b> in multiple places, but do not define it. Providing a definition for <b>Salvage value</b> allows a lessee to standardize reporting and calculate depreciation expense in a manner that will be supported by the definition.</p> <p>In addition, <b>Salvage value</b> clarifies that this value is net of any costs necessary to realize the estimated salvage value of the fixed asset (i.e., disposal costs). Costs to realize a salvage value are calculated independently of liabilities unrelated to the realization of the salvage sale of a fixed asset, such as asset retirement obligations. Therefore, the salvage value cannot be less than zero.</p>
<p><b>Straight-line depreciation method</b> means a method of depreciation that allocates capital costs evenly over the useful life of an asset or the life of the reserve. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the useful life of the fixed asset or the life of the reserve.</p>	<p>The current regulations make references to <b>Straight-line depreciation method</b> in multiple places, but do not define it. Providing a definition for <b>Straight-line depreciation method</b> allows a lessee to standardize reporting and calculate depreciation expense in a manner that will be supported by the definition.</p> <p>In addition, the definition supports both the option for a lessee to select an <b>Alternative in-service date</b> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>
<p><b>Unit-of-production depreciation method</b> means a method of depreciation that allocates capital cost based on the fixed asset’s designed specifications and output parameters. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the units of production for which the</p>	<p>The current regulations make references to <b>Unit-of-production depreciation method</b> in multiple places, but do not define it. Providing a definition for <b>Unit-of-Production depreciation method</b> allows a lessee to standardize reporting and calculate depreciation expense in a manner that will be supported by the definition.</p>

<p>fixed asset was designed.</p>	<p>In addition, the definition supports both the option for a lessee to select an <i>Alternative in-service date</i> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>
<p><i>Units of production</i> means the machine-hours for which an asset was designed to operate or the units of output that an asset was designed to produce. The units of production for a group of fixed assets are the capital-cost-weighted average units of production of the fixed assets comprising the group. Units of production are determined at or prior to the in-service date.</p>	<p>The current regulations make references to <i>Units of production</i> through the <i>Unit-of-production depreciation method</i>, but do not define it. Providing a definition for <i>Unit of production</i> allows a lessee to standardize reporting and calculate depreciation expense in a manner that will be supported by the definition.</p> <p>In addition, the definition supports both the option for a lessee to select an <i>Alternative in-service date</i> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>
<p><i>Useful life</i> means the term over which the asset provides an economic benefit. If a useful life is applied to a group of fixed assets, it is the capital-cost-weighted average useful life of the fixed assets comprising the group. Useful life is measured in, or is convertible into, months and is determined at or prior to the in-service date.</p>	<p>The current regulations make references to life of equipment through the <i>Straight-line depreciation method</i>, but do not define it. Providing a definition for <i>Useful life</i> allows a lessee to standardize reporting and calculate depreciation expense in a manner that will be supported by the definition.</p> <p>Furthermore, the definition supports the definition of <i>Capital cost</i>.</p> <p>Lastly, the definition supports both the option for a lessee to select an <i>Alternative in-service date</i> and the ability to propose depreciation schedules when no prior schedule existed or when the prior schedule was not consistent with ONRR’s regulations.</p>

The following examples demonstrate the application of these definitions when calculating straight-line (useful life), straight-line (life of reserves), and unit-of-production depreciation and undepreciated capital methods:

## Depreciation Schedule Example: Straight-Line Depreciation Method (Useful Life)

Reporting Month

Feb-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Straight-Line	Straight-Line	Straight-Line
<b>Useful Life</b>	<i>Months</i>	240	120	84
<b>Useful Life, Annual Conversion</b>	<i>Years</i>	20	10	7
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	9,958,333.33	165,000.00	0.00
<b>Depreciation Expense</b>	\$	41,666.67	16,500.00	190.48
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	10,000,000.00	181,500.00	190.48
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	41,666.67	1,815,000.00	16,000.00

Reporting Month

Mar-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Straight-Line	Straight-Line	Straight-Line
<b>Useful Life</b>	<i>Months</i>	240	120	84
<b>Useful Life, Annual Conversion</b>	<i>Years</i>	20	10	7
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	10,000,000.00	181,500.00	190.48
<b>Depreciation Expense</b>	\$	0.00	16,500.00	190.48
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	10,000,000.00	198,000.00	380.95
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	0.00	1,798,500.00	15,809.52

## Depreciation Schedule Example: Straight-Line Depreciation Method (Life of Reserve)

Reporting Month

Feb-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Straight-Line	Straight-Line	Straight-Line
<b>Life of Reserve</b>	<i>Months</i>	240	240	240
<b>Life of Reserve, Annual Conversion</b>	<i>Years</i>	20	20	20
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	9,958,333.33	82,500.00	0.00
<b>Depreciation Expense</b>	\$	41,666.67	8,250.00	66.67
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	10,000,000.00	90,750.00	66.67
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	41,666.67	1,897,500.00	16,000.00

Reporting Month

Mar-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Straight-Line	Straight-Line	Straight-Line
<b>Life of Reserve</b>	<i>Months</i>	240	240	240
<b>Life of Reserve, Annual Conversion</b>	<i>Years</i>	20	20	20
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	10,000,000.00	90,750.00	66.67
<b>Depreciation Expense</b>	\$	0.00	8,250.00	66.67
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	10,000,000.00	99,000.00	133.33
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	0.00	1,889,250.00	15,933.33

## Depreciation Schedule Example: Unit-of-Production Depreciation Method

Reporting Month

Feb-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Unit-of-Production	Unit-of-Production	Unit-of-Production
<b>Units of Production</b>	<i>Machine-Hours</i>	32,000	11,200	15,000
<b>Units of Output Utilized, Current Month</b>	<i>Machine-Hours</i>	120	60	100
<b>Accumulated Units of Output Utilized, Beginning Balance</b>	<i>Machine-Hours</i>	31,800	720	0
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	9,937,500.00	127,285.71	0.00
<b>Depreciation Expense</b>	\$	37,500.00	10,607.14	106.67
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	9,975,000.00	137,892.86	106.67
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	62,500.00	1,852,714.29	16,000.00

Reporting Month

Mar-25

Description of Asset	<i>Text</i>	Asset #1	Asset #2	Asset #3
<b>In-Service Date</b>	<i>MM/DD/YYYY</i>	3/15/2005	4/1/2024	2/18/2025
<b>Depreciation Method</b>	<i>Text</i>	Unit-of-Production	Unit-of-Production	Unit-of-Production
<b>Units of Production</b>	<i>Machine-Hours</i>	32,000	11,200	15,000
<b>Units of Output Utilized, Current Month</b>	<i>Machine-Hours</i>	160	100	150
<b>Accumulated Units of Output Utilized, Beginning Balance</b>	<i>Machine-Hours</i>	31,920	780	100
<b>Capital Cost</b>	\$	10,000,000.00	2,000,000.00	16,000.00
<b>Salvage Value</b>	\$	0.00	20,000.00	0.00
<b>Accumulated Depreciation Expense, Beginning Balance</b>	\$	9,975,000.00	137,892.86	106.67
<b>Depreciation Expense</b>	\$	25,000.00	17,678.57	160.00
<b>Accumulated Depreciation Expense, Ending Balance</b>	\$	10,000,000.00	155,571.43	266.67
<b>Undepreciated Capital Cost, Beginning Balance</b>	\$	25,000.00	1,842,107.14	15,893.33

#### 4. Other Related Changes

This proposed rule also seeks to clarify that the reporting period for a non-arm's-length allowance is the reporting month following the production month. This clarification would ensure that expenses are recorded and included in an allowance in the month that they are incurred.

ONRR also notes that the current regulations do not explicitly state the level at which a lessee may select a method of depreciation. Lessees may find it more accurate or appropriate to choose different methods of depreciation for individual assets, segments of a larger system, or groups of assets. Thus, ONRR proposes to amend its regulations to explicitly allow the practice of selecting a method of depreciation at different asset levels and groupings. This proposed change, for example, will allow a lessee to calculate depreciation and a return on undepreciated capital for its allowances at the level of a pipeline segment between two points. Alternatively, a lessee would also have the option to calculate allowances at the level of the individual components of the pipeline segment, such as valves, compressor stations, pipelines, and pig launchers and receivers.

As stated in Section B.2 above regarding clarifying additional allowable transportation costs, this proposed rule clarifies that a lessee may deduct reasonable, actual costs for repairing, replacing, or restoring operability of a plugged or damaged pipeline. When these costs are incurred in a non-arm's-length transportation situation, the lessee would need to classify the costs as operating expenses or capital costs. For example, costs for chemical flushing would be an operating expense whereas the cost of replacing a section of pipeline would be capitalized. After classifying the applicable costs, the lessee would follow the non-arm's-length allowance regulations in the same manner as for other non-arm's-length costs.

Lastly, this proposed rule would re-categorize maintenance expense as an allowable operating expense, which aligns with general accounting practices. Additionally, this clarification reduces the overall number of definitions in the proposed regulations and removes

extraneous distinctions between expenses related to operations and maintenance. The re-categorization of maintenance expense in the proposed regulations does not disallow maintenance expenses that are allowed under the current regulations.

Based on data provided by BOEM, the proposed changes to the non-arm's-length allowance regulations coupled with the proposed changes to the definition of gathering could benefit OCS lessees in the form of clarity, certainty, and cost savings in the calculation and payment of royalties. These benefits could encourage lessees to reinvest in oil and gas production and infrastructure on the OCS. Section II.B.4 discusses these potential future investments, with additional information available in the Preliminary RIA. Similarly, BLM anticipates the proposed changes related to asset depreciation, allowance regulations, and the related definitions may incrementally improve the attractiveness of Federal lands. Assuming an increased interest in Federal onshore oil and gas lease sales results in approximately a 0.5 percent increase in bonus bids, the BLM could potentially expect approximately \$1.2 million in increased bonus bids annually from future lease sales.

As outlined below in Section III, "Requests for Public Comment," ONRR invites public comment on this assumption and these proposed changes to the non-arm's-length allowance regulations and associated definitions.

#### *E. Appeals Amendments*

In addition to the proposed changes to Federal oil and gas and coal valuation regulations, ONRR seeks to clarify the standard of review and timeliness for ONRR Director-level appeals at 30 CFR part 1290. Federal regulations, at 30 CFR part 1290, set forth the procedures for an adversely affected party to appeal an Order issued by a subordinate employee of ONRR or a delegated State ("the issuing office") to the ONRR Director. The ONRR Director currently resolves the vast majority of appeals filed with it informally through its investigation of the appeal and discussions with the appellant. ONRR proposes to revise § 1290.105(f) to codify the ONRR Director's current practice of rendering a formal decision, when necessary, after

reviewing the record before the issuing office along with the written statement of reasons submitted by the appellant. Through this proposed rule, ONRR also seeks to clarify at § 1290.105(f) that the ONRR Director will determine if there is credible evidence to support the Order and shall review all conclusions of law de novo. ONRR also proposes to add language indicating a decision will be rendered within a timely manner and not unreasonably withheld, consistent with the Director's continuing policy to expedite the appeals process when possible. ONRR anticipates the addition of this language will streamline the processing of appeals by providing clarity in the appeals process. ONRR invites public comment on these proposed changes including whether the addition of this language would clarify the appeals review process.

### **III. Requests for Public Comment**

For ONRR's consideration, before reaching a final decision on this action, ONRR requests comments, without limitation, on all components of this proposed action. This includes whether each component of this proposed rule achieves the rule's stated objectives to reduce costs and administrative burden to both ONRR and industry. ONRR is also requesting specific comments on the following:

#### *A. Reevaluated Components of the 2020 Rule:*

##### 1. Default Provision & Misconduct – ONRR seeks public comment on:

- Whether ONRR should remove the default provision and associated definition of misconduct for the reasons noted above.
- If ONRR should consider revising the regulation text at §§ 1206.105 and 1206.144 to resolve the above-referenced ambiguities.
- What ONRR should do to determine value in situations where the regulations do not result in a reasonable valuation method or are inapplicable.

- If ONRR should consider adopting guidance to address the ambiguity issues highlighted or proceed with a regulation change.

## 2. Index-Based Valuation Option – ONRR seeks public comment on:

- Whether ONRR should adopt the proposed index-based valuation option originally contemplated in the 2020 Rule or maintain the status quo currently set forth in its regulations.
- ONRR's assumptions specific to the proposed changes if the index-based valuation option were available for arm's-length dispositions and identifying the complexities industry could avoid.
- Quantifying the administrative burden or savings that a lessee with arm's-length sales would realize if using the index-based valuation option in place of reporting such dispositions using gross proceeds.
- If the requirement to use an ONRR-approved publication when electing the index-based valuation option would impose a cost barrier to smaller companies.
- How changing from the highest bidweek price to a published bidweek index price affects stakeholders.

## 3. Gathering & Offshore Policy – ONRR seeks public comment on:

- The proposed onshore and offshore gathering definition changes, including whether these changes provide clarity and a more consistent application of the gathering rule between non-OCS and OCS lessees.
- Any alternatives to the proposed definition change and related changes in the transportation allowance sections that would provide better clarity and consistency.
- The proposed platform costs that a lessee may include in a transportation allowance, including whether the addition of this language accurately identifies a lessee's

transportation-related platform costs and whether ONRR should consider any alternatives to the proposed language around floating platform costs.

- The addition of language that clarifies how pipeline remediation costs are treated under ONRR's transportation allowance regulations, including whether ONRR should consider any alternatives to this language that would better clarify how pipeline remediation costs should be treated.
- Whether these proposed changes would incentivize producers to seek new leases or increase existing production.

#### 4. Marketable Condition – ONRR seeks public comment on:

- The addition of language to identify where the specifications for marketable condition would be established for residue gas or gas plant products.
- If a definition for “Mainline Pipeline” would be beneficial for additional clarity. For example, would the definition “Mainline Pipeline means a high-pressure gas pipeline that transports production from a field or area to a commercial market, often an interstate pipeline where gas is delivered after processing” provide certainty and cover the situations a lessee may have?

#### 5. Depreciation – ONRR seeks public comment on:

- The proposed provision for how a lessee may handle acquired assets.
- The proposed provision for how a lessee may request an alternative in-service date for its depreciation schedule.
- The proposed definitions related to depreciation.
- The level of interest in the proposed provision to allow capital costs associated with acquired assets in non-arm's-length allowances.
- The level of interest in the proposed provisions to propose alternative in-service dates for assets in non-arm's-length allowances

- The potential costs and administrative burden associated with preparing depreciation schedules for proposal.

6. Appeals – ONRR seeks public comment on:

- Whether the addition of language indicating a decision will be rendered within a timely manner and not unreasonably withheld, will expedite the appeals process and accomplish the goal of providing clarity and early certainty when filing an appeal under part 1290.
- The proposed standard of review for ONRR Director-level appeals and whether the adoption of a different standard such as the scope of review defined under the Administrative Procedure Act would be clearer. *See* 5 U.S.C. 706(2)(A) (referring to “arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law”).

7. Preliminary RIA – ONRR seeks public comments on:

- The findings and assumptions made within its accompanying Preliminary RIA for this proposed rule.
- Other methods to more accurately quantify the economic impacts of the proposed changes.
- If ONRR should consider impacts to other parties or entities not currently referenced in its Preliminary RIA.
- Whether the proposed changes would in fact incentivize industry to increase its production and seek additional leases or lease expansions.

8. Compliance Date – ONRR seeks public comment on:

- Whether it should include a separate compliance date for reporting and payment in the final rule.
- If ONRR incorporates a separate compliance date, should the compliance date extend six months from the effective date or sooner?

## **VI. Procedural Matters**

### *A. Regulatory Planning and Review (E.O. 12866, 13563, and 14192)*

E.O. 12866, amended by E.O. 14215 and 13563, provides that the Office of Information and Regulatory Affairs (“OIRA”) of OMB will review all significant rulemakings. OIRA determined this proposed rule is an economically significant action under E.O. 12866. This proposed rule, if finalized as proposed, is expected to be an E.O. 14192 deregulatory action.

E.O. 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 most innovative and least burdensome tools for achieving regulatory ends. E.O. 13563 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 further emphasizes 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. ONRR developed this rule in a manner consistent with these requirements.

E.O. 14192 defines a deregulatory action as an action that has been finalized and has total costs less than zero. As outlined in the Preliminary RIA and the summaries in this section titled “Procedural Matters,” ONRR anticipates that this action, when finalized, will reduce the amount of overall royalties paid by lessees and therefore impose costs of zero or less. ONRR will reevaluate this statement following its review of the public comments and when this action is finalized, at the final rule stage.

The costs and benefits of the proposed rulemaking are compared against the baseline scenario. The baseline scenario, or status quo, represents ONRR’s assessment of the current practices under the current regulatory framework.

Most of the revisions in the proposed rule would have no or negligible reporting cost impacts for lessees. ONRR anticipates that these changes, however, will likely yield a positive

impact through the increased clarity of the regulation text, which in turn will likely result in more accurate reporting and a potential reduction in the time and cost, to both lessees and ONRR, associated with appeals and litigation. For additional discussion regarding the potential reduction in appeals and litigation time and costs, see the Preliminary RIA. Further, based on feedback provided by BOEM and BLM, ONRR anticipates that lessees may increase production and lease bonus payments above what would have otherwise been in the absence of this proposed rule. Upon review of ONRR's proposed changes, BOEM estimates that the rule may make up to \$205 million in retained earnings potentially available for reinvestment in the deepwater Gulf of America OCS. OCS. Reinvestment is defined as Gulf of America lessees' retained earnings, specifically for revenues and profits generated by Gulf of America leases only, after taxes and dividends. The analysis assumes 100% of these retained earnings will be reinvested into oil and gas development in the Gulf of America rather than used for other business opportunities. Additionally, the analysis assumes that the reinvestment will not extend or improve the ultimate recovery of existing wells but would be used towards the development of incremental volumes in existing fields or new marginal fields. Additionally, for Federal onshore oil and gas lease sales, BLM estimates a total potential additional \$3.6 million annual impact on bonus bids from all proposed changes within one year of the final rule. This example is based on a \$2.4 million increase if expanding the index option increases bonus bids by 1% and an additional \$1.2 million increase if the clarifying amendments result in a 0.5% increase in bonus bids. ONRR requests comment on the estimate of retained earnings, as well as whether 100% of retained earnings may be reinvested in the Gulf of America and other locations, used for existing wells or new development, or used for other purposes not explicitly stated in our assumption. See Section III of the Preliminary RIA for further discussion.

All expected incremental costs of the proposed rule are due to the proposed changes to gathering, allowances, and the index-based valuation option. The table below presents a summary of the quantitative estimates of the annualized and total costs for the proposed rule.

<b>Proposed Rule Change</b>	<b>Change in Estimated Annual Royalty Collections</b>	<b>Estimated Annual Administrative Benefits and Costs</b>
Gathering Definition and Offshore Policy Amendments	(\$329,543,000)	-
Index-Based Valuation Options to Value Federal Gas and NGLs Amendments	(\$1,563,000)	(\$2,572,000)
Change in Royalties: Marketable Condition and Processing Allowances Amendments		
Change in Royalties: Non-arm's-length allowances including Depreciation Amendments		
Change in Royalties: Eliminate Default Provision Requirements and Misconduct Definition for Federal Oil and Gas Amendments		
Appeals Amendments		
<b>Annual Total</b>	<b>(\$331,106,000)</b>	<b>(\$2,572,000)</b>

The estimated changes in royalty collections will change both the amount paid by the lessee and the amount of revenue collected by the Federal Government and disbursed to States and local governments on an annual basis. The net static impact of the proposed amendments is an estimated \$331 million annual decrease in royalty collections. This represents a decrease of approximately two percent of the total Federal oil, gas, and coal royalties that ONRR collected in 2024. The decreased near-term royalty collections may be offset by increased desirability of Federal leases and production on Federal properties due to (i) increased new asset development on Federal properties as a direct result of greater clarity and less economic burden to industry, and (ii) longer economic lives of existing producing assets due to lower lease operating expenses attributable to the reduced royalty collections and potential administrative savings from this

proposed rule. Based on the information provided by BOEM and BLM, the potential increased production may result in greater lease bonus and royalty revenue paid to ONRR over the long-term, which may be greater than near-term reductions in royalty collections. ONRR welcomes comments on the accompanying Preliminary RIA for this proposed rule. The Preliminary RIA can be found in the rulemaking docket at [www.regulations.gov](http://www.regulations.gov).

### *B. Regulatory Flexibility Act*

The Regulatory Flexibility Act (“RFA”), 5 U.S.C. 601-612, requires agencies to analyze the economic impact of regulations when there is likely to be a significant economic impact on a substantial number of small entities and to consider regulatory alternatives that will achieve the agency’s goals while minimizing the burden on small entities. When an agency issues a notice of proposed rulemaking, the RFA requires the agency to “prepare and make available for public comment an initial regulatory flexibility analysis” which will “describe the impact of the proposed rule on small entities.” 5 U.S.C. 603(a). ONRR evaluated multiple alternatives to the proposed changes in its Preliminary RIA. For the reasons outlined in the Preliminary RIA, ONRR is not adopting any of those alternatives as part of this rulemaking. *See* Preliminary RIA, Sec. VI. Analysis of Alternatives. ONRR certifies that this proposed rule would not have a significant economic impact on a substantial number of small entities for the reasons outlined below.

Lessees under this proposed rule primarily fall under the Small Business Administration’s (“SBA”) North American Industry Classification System (“NAICS”) codes 211120 (crude petroleum extraction), 211130 (natural gas extraction), 212115 (underground coal mining), and 212114 (surface coal mining). For NAICS classifications 211120, 211130, and 212114, SBA defines a small business as one with fewer than 1,250 employees, and 1,500 employees for underground coal mining. Using company demographic data of royalty reporters, ONRR estimates 91.9 percent of oil and gas reporters are considered “small entities” under the SBA’s size definition of 1,250 employees. All oil and gas reporters would be impacted by the

proposed rule if they report and pay on Federal oil and gas leases. Therefore, ONRR determined the proposed changes would affect a substantial number of small entities.

As stated in the Summary of Royalty Impacts and Costs Table, this rule would benefit industry through a reduction in royalties of approximately \$331 million per year. For FY 2022-2024, small businesses accounted for about four percent of the royalties collected by ONRR. Applying that percentage to industry costs, ONRR estimated that the changes in the proposed rule would result in royalty savings to small business lessees of approximately \$13.24 million per year, on average. This annual average savings over ten years, when discounted at seven percent, would represent over \$92.8 million in savings for small businesses. The extent of an economic impact, if any, would vary between companies due to, for example, differences in the volume of production that the small business produces and sells each year. This proposed rule provides businesses with more flexibility as each entity, including small businesses, are able to determine whether it is economically advantageous to incur increases in administrative costs to reduce the royalties paid, based on an entity's individual circumstances.

The regulatory changes in this proposed rule are primarily clarifications or reflect ONRR regulatory updates to maintain consistency between ONRR's regulations and current practices. Most lessees have been reporting and paying based on these existing practices. Instead, this rule provides businesses with more flexibility as each entity, including small businesses, can determine whether it is economically advantageous to incur increases in administrative costs to reduce the royalties paid, based on an entity's individual circumstances. Moreover, the Federal coal proposed regulatory changes do not significantly impact ONRR's coal reporters because the only regulatory change for Federal coal is the inclusion of definitions to clarify depreciation and the request for companies proposing a depreciation schedule, not already included in 30 CFR part 1206, to submit a depreciation schedule to ONRR. With the estimated reduction in royalty payments and clarified requirements as specified in the Preliminary RIA, ONRR estimates that any impacts from this proposed rule will be a resulting positive impact. However, ONRR solicits

public comment on this assumption. Therefore, ONRR does not anticipate that these regulatory updates will have a significant economic impact on small or large operators. To further assist large and small lessees, ONRR will provide reporting training, dear reporter letters, and compliance guidance upon publication of a final rule.

#### *C. Unfunded Mandates Reform Act*

This proposed rule would not impose an unfunded mandate or have a significant effect on State, local, or Tribal governments, or on the private sector, of more than \$100 million per year. Therefore, ONRR is not required to provide a statement pursuant to the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*).

#### *D. Takings (E.O. 12630)*

Under the criteria in sec. 2 of E.O. 12630, this proposed rule does not have any significant takings implications. This proposed rule does not impose restrictions or limitations on the use of any private property. Through this proposed action, ONRR seeks to clarify its regulations and reduce administrative burden to industry that apply to Federal oil, gas, and coal valuation for royalty computation purposes. Therefore, this proposed rule does not require a takings implication assessment.

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

Under the criteria in Section 1 of E.O. 13132, the proposed rule does not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. The management of Federal oil and gas is the responsibility of the Secretary, and ONRR distributes all the royalties that it collects under Federal oil and gas leases as directed by the relevant disbursement statutes. As outlined in the Preliminary RIA, ONRR anticipates that this proposed rule will not directly impose administrative costs on States or local governments. ONRR does not anticipate this rule altering the relationship between the Federal and State governments as defined in E.O. 13132; however, ONRR invites public comment on this topic as part of this proposed rule.

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

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

(1) Meets the criteria of Section 3(a), which requires that ONRR review all regulations to eliminate errors and ambiguity to minimize litigation.

(2) Meets the criteria of Section 3(b)(2), which requires that all regulations be written in clear language using clear legal standards.

*G. Consultation with Indian Tribal Governments (E.O. 13175)*

ONRR strives to strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian Tribes and recognition of their right to self-governance and Tribal sovereignty. ONRR evaluated this proposed rule under the Department's consultation policy and the criteria in E.O. 13175 and determined that it does not have substantial direct effects on federally recognized Indian Tribes, as it only applies to Federal oil, gas, and coal leases. Thus, consultation under ONRR's Tribal consultation policy is not required.

*H. Paperwork Reduction Act (44 U.S.C. 3501 et seq.)*

The Paperwork Reduction Act ("PRA") (44 U.S.C. 3501 *et seq.*) requires an agency to have a currently valid OMB control number to require collection of information from a person or entity. Such collections of information include any request or requirement that person obtain, maintain, retain, or report information to an agency or disclose information to a third party or to the public (44 U.S.C. 3502(3) and 5 CFR 1320.3(c)). This proposed rule contains ONRR information collection requests subject to review by OMB under the PRA. ONRR proposes the following two information collections as part of this rulemaking:

**1. OMB Control Number 1012-NEW**

Under the proposed changes at §§ 1206.112(i)(4), 1206.154(i)(4), and 1206.161(h)(4), a lessee may propose to ONRR a depreciation schedule if no depreciation schedule exists or has

existed for an in-service fixed asset or if the depreciation schedule for an in-service fixed asset does not comply with the associated non-arm's-length allowance regulations. The depreciation schedule would identify the fixed assets covered by the proposal. Each fixed asset entry must include the capital cost, the in-service date, the method of depreciation elected, the salvage value, and either the useful life, units of production, or life of reserve. For fixed assets depreciated as a group, the depreciation schedule shall demonstrate, or allows for the calculation of, either the group's useful life, units of production, or life of the reserve. The depreciation schedule shall include, or allows for the calculation of, depreciation expense during the reporting period and the undepreciated capital cost. A lessee may also provide supporting documentation as established in the proposed regulation text.

Under the proposed changes at §§ 1206.111(b)(12-14), 1206.112(d), 1206.153(b)(12-14), and 1206.154(c)(3), ONRR clarifies which OCS platform costs may be included in a transportation allowance in the regulations. This includes platform costs related to flow assurance as well as costs associated with pumps used to deliver oil into the export pipeline leaving the platform. For gas, deductible costs for equipment that requires space on the platform include those associated with the compression, dehydration, and treatment of gas to the extent that those services are required for transportation and exceed the services necessary to place production into marketable condition. Accordingly, the platform costs directly allocable to the space needed to house the allowed equipment are deductible, and platform space costs are allocated based on the square footage required for the allowed pieces of equipment.

Additionally, under the proposed changes at §§ 1206.112(i)(1), 1206.154(i)(1), and 1206.161(h)(1), a lessee may propose to ONRR a depreciation schedule and an alternative in-service date if the lessee or prior owners never claimed an allowance that included depreciation expense and a return from on undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset.

Thus, in sum, ONRR would be collecting the following new information associated with

the proposed depreciation changes for Federal oil and gas:

- Alternative in-service date – 30 CFR 1206.112(i)(1), 30 CFR 1206.154(i)(1), and 30 CFR 1206.161(h)(1)
- Platform costs – 30 CFR 1206.111(b)(12-14), 30 CFR 1206.112(d), 30 CFR 1206.153(b)(12-14), and 30 CFR 1206.154(c)(3)
- Depreciation schedule proposal – 30 CFR 1206.112(i)(4), 30 CFR 1206.154(i)(4), and 30 CFR 1206.161(h)(4)

This ICR is associated with the information covered for Federal oil and gas reporting and royalty payments in OMB Control Number 1012-0005. Following the publication of ONRR's Federal Oil, Gas, and Coal Amendments Final Rule (RIN 1012-AA39) and subsequent approval by OMB, ONRR intends to revise OMB Control Number 1012-0005 to incorporate the information collection in this ICR. Once these information collections have been incorporated into OMB Control Number 1012-0005 and approved by OMB, ONRR will discontinue this ICR.

*Title of Collection:* Federal Oil and Gas Depreciation and Platform Cost Collections—30 CFR part 1206.

*OMB Control Number:* 1012-NEW.

*Form Number:* None.

*Type of Review:* New information collection.

*Respondents/Affected Public:* Businesses.

*Total Estimated Number of Annual Respondents:* 753 Federal lessees/designees.

*Total Estimated Number of Annual Responses:* 753.

*Estimated Number of Annual Burden Hours:* 46,344 hours.

*Estimated Completion Time per Response:* The average completion time is 61.54 hours per response. The average completion time is calculated by dividing the total estimated burden hours (46,344) by the estimated annual responses (753).

*Respondent's Obligation:* The information that a lessee must submit pursuant to 30 CFR part

1206 for proposing an alternative in-service date and depreciation schedule to ONRR as well as accounting for platform costs for Federal oil and gas leases is required to obtain or retain a benefit.

*Frequency of Collection:* Annually and on occasion.

*Estimated Annual Nonhour Burden Cost:* ONRR has identified no “nonhour” cost burden associated with the collection of information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

*Authority:* Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq*).

## **2. OMB Control No. 1012-NEW**

OMB has reviewed and approved information collections for the existing solid mineral and geothermal resource regulations at 30 CFR parts 1202, 1206, 1210, 1212, 1217, and 1218, which are assigned to OMB Control No. 1012-0010. As part of this proposed rule, ONRR intends to create a new information collection request because of the changes to Federal solid minerals proposed in this action. The following changes result in additional information collections from industry and therefore require OMB’s approval. The proposed new information collection requirements are as follows:

ONRR proposes to change §§ 1206.259(b)(2)(v), 1206.262(b)(2)(v) within its solid minerals regulations, which would allow a lessee to propose a depreciation schedule if no depreciation schedule exists or has existed for an in-service fixed asset or if the depreciation schedule for an in-service fixed asset does not comply with the associated non-arm’s-length allowance regulations. Similar changes are also proposed at §§ 1206.259(b)(2)(v)(B) and 1206.262(b)(2)(v)(B) regarding a lessee’s ability to propose a depreciation schedule and an alternative in-service date to ONRR under certain circumstances outlined above in the preamble to this proposed rule.

Thus, in sum, ONRR would be collecting the following new information associated with

the proposed depreciation changes for Federal solid minerals:

- Alternative in-service date – 30 CFR 1206.259(b)(2)(v)(B)(1) and 30 CFR 1206.262(b)(2)(v)(B)(1)
- Depreciation schedule proposal – 30 CFR 1206.259(b)(2)(v)(D) and 30 CFR 1206.262(b)(2)(v)(D)

This ICR is associated with the information covered for solid minerals reporting and royalty payments in OMB Control Number 1012-0010. Following the publication of ONRR's Federal Oil, Gas, and Coal Amendments Final Rule (RIN 1012-AA39) and subsequent approval by OMB, ONRR intends to revise OMB Control Number 1012-0010 to incorporate the information collection in this ICR. Once these information collections have been incorporated into OMB Control Number 1012-0010 and approved by OMB, ONRR will discontinue this ICR.

*Title of Collection:* Federal Solid Minerals Depreciation Collections—30 CFR part 1206.

*OMB Control Number:* 1012-NEW.

*Form Numbers:* N/A.

*Type of Review:* New information collection.

*Respondents/Affected Public:* Businesses.

*Total Estimated Number of Annual Respondents:* 100 reporters.

*Total Estimated Number of Annual Responses:* 10.

*Total Estimated Number of Annual Burden Hours:* 80 hours.

*Estimated Completion Time per Response:* The average completion time is 8 hours per response.

The average completion time is calculated by dividing the total estimated burden hours (80) by the estimated annual responses (10).

*Respondent's Obligation:* The information is required to obtain or retain a benefit.

*Frequency of Collection:* Monthly, annually, and on occasion.

*Estimated Annual Non-Hour Cost Burden:* ONRR has identified no "non-hour" cost burden associated with the collection of information.

An agency may not conduct or sponsor and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number.

The authority for this action is the PRA (44 U.S.C. 3501 *et seq.*).

#### *I. National Environmental Policy Act of 1969*

This proposed rule does not constitute a major Federal action significantly affecting the quality of the human environment. ONRR is not required to provide a detailed statement under the National Environmental Policy Act of 1969 (“NEPA”) because this proposed rule qualifies for a categorical exclusion under 43 CFR 46.210(c) and (i), as well as the Departmental Manual, part 516, sec. 15.4.D, which covers: “(c) Routine financial transactions including such things as . . . audits, fees, bonds, and royalties . . . [and] (i) [p]olicies, directives, regulations, and guidelines . . . [t]hat are of an administrative, financial, legal, technical, or procedural nature.” ONRR also determined that this proposed rule does not involve any of the extraordinary circumstances listed in 43 CFR 46.215 that require further analysis under NEPA.

#### *J. Effects on the Energy Supply (E.O. 13211)*

OIRA determined this proposed rule is significant under E.O. 12866, but it has not yet determined whether this rulemaking is deemed as a significant energy action under E.O. 13211 Section 4(b). ONRR asserts that this rulemaking does not meet the definition of a significant energy action because the proposed rule’s contents are not likely to have a significant adverse effect on the supply, distribution, or use of energy. As a result, ONRR did not prepare a Statement of Energy Effects pursuant to E.O. 13211 as one is not required. If OIRA deems this rulemaking a significant energy action, ONRR will address this section appropriately.

#### *K. Severability Statement*

If any provision, or portion of a provision, of this proposed rule is found, by a court or tribunal of competent jurisdiction, to be invalid under the law, it shall be regarded as stricken while the remainder of this rule, if finalized, shall proceed to go in full effect.

#### *L. Clarity of this Regulation*

E.O. 12866 (sec. 1(b)(12)), 12988 (sec. 3(b)(1)(B)), E.O. 13563 (sec. 1(a)), and the Presidential memorandum of June 1, 1998, require ONRR to write all rules in plain language.

This means that the rules ONRR publishes must use:

- (1) Logical organization.
- (2) Active voice to address readers directly.
- (3) Clear language rather than jargon.
- (4) Short sections and sentences.
- (5) Lists and tables wherever possible.

If you believe that ONRR has not met these requirements, send your comments to *ONRR\_RegulationsMailbox@onrr.gov*. To better help ONRR understand your comments, please make your comments as specific as possible. For example, you should tell ONRR the numbers of the sections or paragraphs that you think were written unclearly, the sections or sentences that you think are too long, and the sections for which you believe lists or tables would be useful.

This action is taken pursuant to delegated authority.

### **List of Subjects**

#### **30 CFR Part 1206**

Coal, Continental shelf, Geothermal energy, Government contracts, Government employees, Indians-lands, Mineral royalties, Oil and gas exploration, Public lands-mineral resources, Reporting and recordkeeping requirements.

#### **30 CFR Part 1290**

Administrative practice and procedure.

**April Lockler,**

*Acting Director of the Office of Natural Resources Revenue.*

## **Authority and Issuance**

For the reasons discussed in the preamble, under the authority provided by Reorganization Plan No. 3 of 1950 (64 Stat. 1262) and S.O. 3299, ONRR proposes to amend 30 CFR parts 1206 and 1290 as follows:

### **PART 1206—PRODUCT VALUATION**

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

**Authority:** 5 U.S.C. 301 *et seq.*, 25 U.S.C. 396, 396a *et seq.*, 398, 398a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

#### **Subpart A – General Provisions and Definitions**

2. Revise and republish 1206.20 as follows:

##### **§ 1206.20 What definitions apply to this part?**

The definitions in this section do not apply to subparts B, E, F and J of this part.

*Actual cost* means a cost incurred by a lessee. Actual costs do not include imputed costs, theoretical costs, or avoided costs.

*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 other 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.

*Alternative in-service date* means the date selected under § 1206.112(i)(1)(i) for Federal oil, § 1206.154(i)(1)(i) or § 1206.161(h)(1)(i) for Federal gas, or § 1206.259(b)(2)(v)(B)(1) or § 1206.262(b)(2)(v)(B)(1) for Federal coal from which the lessee will apply its depreciation schedule in calculating non-arm's-length allowance. The term "alternative in-service date" has no meaning outside of the commodities and regulations mentioned.

*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.

*Capital cost* means the actual cost associated with the initial purchase or construction of a fixed asset with a useful life greater than one year. Actual costs incurred to improve a fixed asset, enhance or modify a fixed asset's functionality, or extend the useful life of a fixed asset are also capital costs when the economic benefits of the changes extend beyond one year. Capital costs include those costs reasonable and necessary to bring the fixed asset to the condition and location of its intended use, such as shipping, delivery, and installation cost. The capital cost of a fixed asset reflects its value when measured at the in-service date.

*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.

*Depreciation* means the systematic and rational allocation of the capital cost less a reasonable salvage value of a fixed asset to expense during periods when economic benefits are available to obtain from the fixed asset. Depreciation begins at the in-service date.

*Depreciation schedule* means a document used to record and track depreciation for a fixed asset. A depreciation schedule includes a list of fixed assets that can be separately identified. Each fixed asset entry must include the capital cost, the in-service date, the method of depreciation elected, the salvage value, and either the useful life, units of production, or life of reserve. For fixed assets depreciated as a group, the depreciation schedule shall demonstrate, or allow for the calculation of, either the group's useful life, units of production, or life of the reserve. The depreciation schedule includes, or allows for the calculation of, depreciation expense during the reporting period and the undepreciated capital cost.

*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.

*First-of-month convention* means that depreciation begins on the first day of the month of the in-service date or alternative in-service date.

*Fixed assets* means tangible assets owned or controlled by a lessee that are used to produce or provide goods and services in the primary business activities of that entity. Fixed assets have a useful life greater than one year.

*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:

1. For production from non-OCS leases, the movement of production from the well to the BLM-approved FMP for royalty measurement.
2. For production from OCS leases, the movement of production from the well to one of the following locations, whichever is nearest to the well:
  - (i) the first point at which the production from two or more wells accumulate;
  - (ii) the point at which the production of a well is first separated into discrete constituents; or
  - (iii) the boundaries of the lease.

*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 saltwater 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.

*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.

*In-service date* means the earlier of the date when a fixed asset is placed in service or the date when a fixed asset is functionally ready and available for its intended use. When considering a group of fixed assets, the group in-service date is the in-service date for the primary functional fixed asset of the group.

*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 any person who has an interest in a lease.

*Life of the reserve* means the estimated term over which the natural reserve provides an economic benefit. A life of the reserve estimate is based on a report from an unaffiliated or independent expert and clearly identifies the assumptions supporting the estimate. If a fixed asset services multiple reserves, the life of the reserve represents the average of the individual reserve life estimates. Life of the reserve is measured in, or is convertible into, months and is determined at or prior to the in-service date.

*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.

*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.

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

*Operating Expense* means costs associated with the production or provision of goods and services by a business. Operating expenses are costs necessary for the company's normal, core business activities.

*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.

*Overhead* means the indirect costs of producing or providing goods and services. Overhead must be systematically and rationally allocated to the goods or services being produced or provided.

Overhead is a cost necessary for the company's normal, core business activities.

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

*Reserve* means the estimated quantity of known accumulations of a natural resource anticipated to be commercially recoverable from a defined area under existing economic conditions and by established operating practices from a given date forward.

*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, or gas plant product to the buyer and does not retain any related rights, such as the right to buy back similar quantities of oil, gas, or gas plant product from the buyer elsewhere;

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

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

*Salvage value* means the value net of disposal costs that the payor expects to realize at the end of the useful life of an asset. Salvage values are designed to minimize any gain or loss at the time of disposal. Salvage value is greater than or equal to zero. Salvage value is determined at or prior to the in-service date.

*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.

*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.

*Straight-line depreciation method* means a method of depreciation that allocates capital costs evenly over the useful life of an asset or the life of the reserve. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the useful life of the fixed asset or the life of the reserve.

*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 website, [www.cmegroup.com](http://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.

*Unit-of-production depreciation method* means a method of depreciation that allocates capital cost based on the fixed asset's designed specifications and output parameters. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the units of production for which the fixed asset was designed.

*Units of production* means the machine-hours for which an asset was designed to operate or the units of output that an asset was designed to produce. The units of production for a group of fixed assets are the capital-cost-weighted average units of production of the fixed assets comprising the group. Units of production are determined at or prior to the in-service date.

*Useful life* means the term over which the asset provides an economic benefit. If a useful life is applied to a group of fixed assets, it is the capital-cost-weighted average useful life of the fixed assets comprising the group. Useful life is measured in, or is convertible into, months and is determined at or prior to the in-service date.

*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.

### **Subpart C – Federal Oil**

3. Amend § 1206.101 by:

- a. Revising paragraphs (a) introductory text, (c)(1) introductory text, and (c)(1)(i); and
- b. Adding paragraph (d).

The revisions and addition read as follows:

#### **§ 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 one of the exceptions in paragraph (d) of this section applies. You must use this paragraph (a) to value oil when:

\* \* \*

(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.

(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 require you to value the oil under § 1206.102. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

\* \* \*

(d) This paragraph contains exceptions to the valuation rule in paragraph (a) of this section.

Apply these exceptions on an individual contract basis.

(1) In conducting reviews and audits, if ONRR determines that any arm's length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, ONRR may require that you value the oil sold under that contract either under § 1206.102 or at the total consideration received.

(2) You must value the oil under § 1206.102 if ONRR determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

4. Amend § 1206.102 by revising the introductory text and paragraphs (d) and (e) to read as follows:

**§ 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. 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.

\* \* \* \* \*

(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 establish a reasonable royalty value based on other relevant criteria.

(e) Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.

(1) Instead of valuing your production under paragraph (a), (b), or (c) of this section, you may apply to ONRR to establish a value representing the market at the refinery if:

(i) You transport your oil directly to your or your affiliate's refinery, or exchange your oil for oil delivered to your or your affiliate's refinery; and

(ii) You must value your oil under this section at the NYMEX price or ANS spot price; and

(iii) You believe that use of the NYMEX price or ANS spot price results in an unreasonable royalty value.

(2) You must provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to:

(i) Costs of acquiring other crude oil at or for the refinery;

(ii) How adjustments for quality, location, and transportation were factored into the price paid for other oil;

(iii) Volumes acquired for and refined at the refinery; and

(iv) Any other appropriate evidence or documentation that ONRR requires.

(3) If ONRR establishes a value representing market value at the refinery, you may not take an allowance against that value under § 1206.113(b) unless it is included in ONRR's approval.

5. Revise and republish § 1206.104 to read as follows:

**§ 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 establish a reasonable royalty value based on other relevant criteria.

(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) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Federal oil, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant criteria.

(c) ONRR may establish a reasonable royalty value based on other relevant criteria 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; 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 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 put 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 establish a reasonable royalty value based on other relevant criteria.

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

6. Remove and reserve § 1206.105.

#### **§ 1206.105 [Removed and Reserved]**

7. Amend § 1206.110 by

a. removing paragraphs (a)(1)(i) and (a)(1)(ii);

b. revising paragraph (a)(1); and

c. revising paragraph (f) introductory text and (f)(2).

The revisions read as follows:

#### **§ 1206.110 What general transportation allowance requirements apply to me?**

(a) \* \* \*

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

\* \* \* \* \*

(f) ONRR may direct you to modify your transportation allowance if:

\* \* \*

(f)(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; or

\* \* \* \* \*

8. Amend § 1206.111 by:

a. adding paragraphs (b)(12), (b)(13), (b)(14), (c)(9);

b. revising paragraph (d); and

c. removing paragraphs (d)(1) and (d)(2).

The revisions read as follows:

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

\* \* \* \* \*

(b) \* \* \*

(12) Flow assurance costs. You may deduct costs associated with ensuring the flow of oil through a pipeline. This includes, but is not limited to, flow assurance chemicals, pipeline pigging equipment, and heated pipelines. This does not include the cost of operations required for producing oil, such as, but not limited to, chemicals injected in the wellbore to bring production to the surface.

(13) OCS platform costs. You may deduct costs directly allocable to:

(i) Oil pumps used to deliver oil into the export pipeline leaving the platform.

(ii) Flow assurance as described in paragraph (12) of this section.

(iii) Platform space required to house equipment in paragraphs (i) and (ii) of this section.

(iv) Platform buoyancy required to support the weight of equipment in (i), (ii), and (iii).

(14) Costs to repair, replace, or restore operability of a plugged or damaged pipeline. You may deduct your reasonable actual costs for repairing, replacing, or restoring operability of a plugged

or damaged pipeline. If you receive insurance compensation, you must reduce your allowance by the compensation received.

(c) \* \* \*

(9) Any OCS platform costs not included in paragraph (b)(13) of this section.

(d) If you have no written contract for the arm's-length transportation of oil, you must propose to ONRR a method to determine the allowance using the procedures in § 1206.108(a). You may use that method to determine your allowance until ONRR issues its valuation determination.

9. Revise and republish § 1206.112 as follows:

**§ 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) You or your affiliate's actual costs may include the following:

(1) Operating expenses under paragraph (f) of this section,

(2) Overhead under paragraph (g) of this section.

(3) Either:

(i) Depreciation expense and a return on undepreciated capital costs under paragraph (i) of this section, or

(ii) A cost equal to a return on the initial depreciable capital costs of the transportation system under paragraph (j) of this section.

(iii) Once 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) The reporting period when you do not have an arm's-length transportation contract is the reporting month following the production month.

(c) To the extent not included in costs identified in paragraphs (e) through (g) of this section, 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:

(1) 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

(2) 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

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

(4) Fees paid to a non-affiliated quality bank administrator for administration of a quality bank

(5) 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 (c)(5)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in paragraph (k) of this section by 12.

(6) Only OCS platform costs directly allocable to the following:

(i) Oil pumps used to deliver oil into the export pipeline leaving the platform.

(ii) Flow assurance as described in § 1206.111(b)(12).

(iii) Platform space required to house equipment in paragraphs (i) and (ii) of this section.

(iv) Platform buoyancy required to support the weight of equipment in (i), (ii), and (iii).

(d) You may not include in your transportation allowance:

(1) Any of the costs identified under § 1206.111(c); or

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

(3) Any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(e) Allowable capital costs are those for fixed assets 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) Maintenance

(10) Maintenance labor

(11) Any other directly allocable and attributable operating expense that you can document

(g) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense.

(h) State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(i) To calculate depreciation expense and a return on undepreciated capital costs:

(1) Depreciation and a return on undepreciated capital costs are calculated from the in-service date.

(i) If you or prior owners never claimed an allowance that included depreciation expense and a return on undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset, you may propose an alternative in-service date under (i)(4) of this section.

(ii) The alternative in-service date must not extend beyond the in-service date as extended by the shorter of the useful life and the life of the reserve.

(iii) You may not select the unit-of-production method when applying an alternative in-service date.

(iv) The application of an alternative in-service date does not change the useful life or life of the reserve.

(2) You may elect to use either a straight-line depreciation method or you may elect to use a unit-of-production depreciation method to calculate depreciation expense except when the alternative in-service date is applied under paragraph (i)(1)(i) of this section.

(i) Depreciation expense using the straight-line depreciation method is the rate of depreciation from the in-service date through the end of the useful life or life of the reserves under the first-of-month convention.

(ii) Depreciation expense using units-of-production depreciation is the product of the rate of depreciation and the units of output produced in the reporting period.

(iii) You may choose to apply these depreciation methods individually to each fixed assets or group of fixed assets.

(iv) 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.

(3) Lessees may include allowable depreciation expense for acquired fixed assets as part of a transportation allowance. If you have a depreciation schedule that the original transporter/lessee established in compliance with 30 CFR part 1206 for purposes of the allowance calculation, a change in ownership of a transportation system will not alter that depreciation schedule.

(4) Proposing a depreciation schedule to ONRR:

(i) If no depreciation schedule under 30 CFR part 1206 exists or has existed for an in-service fixed asset, you may propose to ONRR a depreciation schedule for your transportation allowance.

(ii) If the depreciation schedule for an in-service fixed asset does not comply with 30 CFR part 1206, you may propose to ONRR a depreciation schedule for your transportation allowance.

(iii) ONRR will consider the following factors when reviewing a proposed depreciation schedule for approval:

(A) The lessee's or a prior owner's published capitalization policy, depreciation policy, fixed asset useful life policy, and any related policies in effect during the applicable period, when provided by the proposing lessee;

(B) Consistency with audited financial statements that have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"), when supporting records and reconciliations are provided by the proposing lessee;

(C) Documents prepared in support of the recording and capitalization of fixed assets under U.S. GAAP, when provided by the proposing lessee;

(D) Purchase price allocation reports prepared in accordance with U.S. GAAP by independent experts, when provided by the proposing lessee;

(E) Practices typical of the industry; and

(F) Any information that ONRR deems relevant regarding the depreciation schedule.

(iv) You may use your proposed depreciation schedule to calculate a transportation allowance beginning with the production month following the month when ONRR received your proposal until ONRR accepts or rejects it. If ONRR rejects your proposed depreciation schedule, 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.

(5) You may depreciate a transportation system, with or without a change in ownership, only once.

(6) To calculate the return on undepreciated capital cost, you may use an amount equal to the undepreciated capital cost of the transportation system at the beginning of the reporting period

multiplied by the rate of return that you determine under paragraph (k) of this section. After you have depreciated a transportation system to the reasonable salvage value, you may thereafter include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (k) of this section.

(j) As an alternative to using depreciation expense and a return on undepreciated capital cost, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital cost of 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.

10. Revise and republish § 1206.141 as follows:

**§ 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

(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. Unless you elect to value your gas under paragraph (c) of this section, 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) Alternatively, you may elect to value your unprocessed gas under this paragraph (c), which allows you to use an index-based valuation method to calculate royalty value. 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 published bidweek index price to which your gas may flow for that respective 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 of the published bidweek index prices to which your gas may flow for that respective 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 may adjust the number calculated under paragraphs (c)(1)(i) and (ii) of this section by reducing the value by 20 percent, but not more than 74 cents per MMBtu for sales from the OCS Gulf of America and by 13 percent, but not more than 45 cents per MMBtu, for sales from all other areas.
- (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 criteria for 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:

(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 its decision.

(iii) After ONRR issues its valuation determination, you must make the adjustments under § 1206.143(a)(2).

(f) Under no circumstances may your gas be valued for royalty purposes less than zero.

(g) If you elect to value your gas under paragraph (c) of this section, ONRR reserves the right to collect actual transaction data in the future to assess the validity of the index-based valuation option.

11. Revise and republish § 1206.142 as follows:

**§ 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 based on 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. Unless you exercise the option provided in paragraph (d) of this section, 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;

(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, 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) Alternatively, you may elect to value your residue gas and/or 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 published bidweek index price to which your gas may flow for that respective 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 of the published bidweek index prices to which your gas may flow for that respective 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 residue gas enters the pipeline.

(iv) You may adjust the number calculated under paragraphs (d)(1)(i) and (ii) of this section by reducing the value by 20 percent but not more than 74 cents per MMBtu for sales from the OCS Gulf of America and by 13 percent but not more than 45 cents per MMBtu for sales from all other areas.

(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 criteria for 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 method that ONRR will use to calculate the amounts is set forth in the preamble to this regulation. This method is binding on you and ONRR. ONRR will update the amounts periodically using this method.

(iii) After you select an ONRR-approved commercial price bulletin available at *www.onrr.gov*, you must 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 website.

(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:

(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 its valuation determination, you must make the adjustments under § 1206.143(a)(2).

(g) Under no circumstances may your gas be valued for royalty purposes less than zero.

(h) If you elect to value your gas under paragraph (d) of this section, ONRR reserves the right to collect actual transaction data in the future to assess the validity of the index-based valuation option.

12. Revise and republish § 1206.143 as follows:

**§ 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.

(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) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Federal gas, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant criteria.

(c) ONRR may direct you to use a different measure of royalty value 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 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 direct you to use a different measure of royalty value.

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

13. Remove and reserve § 1206.144.

#### **§ 1206.144 [Removed and Reserved]**

14. Amend § 1206.146 to add paragraph (c) as follows:

#### **§ 1206.146 What are my responsibilities to place production into marketable condition and to market production?**

\* \* \* \* \*

(c) Your gas or gas plant products are in marketable condition when it meets the required quality specifications for either:

(1) Delivery to a Mainline Pipeline. If your gas or gas plant products are delivered to a mainline pipeline that transports gas to market, it must meet the quality specifications set by that pipeline operator. This is typically the specifications required for delivery at the outlet of a gas processing plant;

(2) Delivery other than Mainline Pipeline. If your gas or gas plant products are delivered to market by means other than through a mainline pipeline, then your gas is in marketable condition when it meets the specifications required by the receiving transporter or purchaser; or

(3) Alternative Market for Unprocessed Gas. If your gas is never processed and you can reasonably support that a market exists at another location, you can use the quality specifications required at that alternative delivery point.

15. Amend § 1206.152 by:

a. revising paragraph (a)(2);

b. removing paragraphs (a)(2)(i) and (ii); and

c. revising paragraphs (g) introductory text and (g)(2).

The revisions read as follows:

**§ 1206.152 What general transportation allowance requirements apply to me?**

(a) \* \* \*

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

\* \* \* \* \*

(g) ONRR may direct you to modify your transportation allowance if:

(1) \* \* \*

(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; or

\* \* \* \* \*

16. Revise and republish § 1206.153 as follows:

The revisions read as follows:

**§ 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).

(12) ***Flow assurance costs.*** You may deduct costs associated with ensuring the flow of gas through a pipeline. This includes, but is not limited to, flow assurance chemicals, pipeline pigging equipment, and heated pipelines. This does not include the cost of operations required for producing gas, such as, but not limited to, chemicals injected into the wellbore to bring production to the surface.

(13) ***OCS platform costs.*** You may deduct costs directly allocable to:

(i) Services described in paragraph (9) of this section.

(ii) Flow assurance as described in paragraph (12) of this section.

(iii) Platform space required to house equipment in paragraphs (i) and (ii) of this section.

(iv) Platform buoyancy required to support the weight of equipment in (i), (ii), and (iii).

(14) ***Costs to repair, replace, or restore operability of a plugged or damaged pipeline.*** You may deduct your reasonable actual costs for repairing, replacing, or restoring operability of a plugged

or damaged pipeline. If you receive insurance compensation, you must reduce your allowance by the compensation received.

(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) of this chapter.

(9) Any OCS platform costs not included in paragraph (b)(13) of this section.

(d) If you have no written contract for the arm's-length transportation of gas, and neither you nor your affiliate perform your own transportation, you must propose to ONRR a method to determine the transportation allowance using the procedures in § 1206.148(a). You may use that method to determine your allowance until ONRR issues its valuation determination.

17. Revise and republish § 1206.154 as follows:

**§ 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) Operating expenses under (f) of this section.

(2) Overhead under paragraph (g) of this section.

(3) Either:

(i) Depreciation expense and a return on undepreciated capital costs under paragraph (i) of this section, or

(ii) A cost equal to a return on the initial undepreciated capital cost of the transportation system under paragraph (j) of this section.

(iii) Once 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) The reporting period when you do not have an arm's-length transportation contract is the reporting month following the production month.

(c) To the extent not included in costs identified in paragraphs (e) through (g) of this section, if you or your affiliate incur(s) actual costs under your or your affiliate's non-arm's-length contract, you may include those costs in your calculations under this section:

(1) The actual transportation costs listed under § 1206.153(b)(2), (5), (6), (9), (12), and (14) of this subpart.

(2) Only OCS platform costs directly allocable to the following:

(i) Services described in § 1206.153(b)(9) of this section.

- (ii) Flow assurance as described in § 1206.153(b)(12).
- (iii) Platform space required to house equipment in paragraphs (i) and (ii) of this section.
- (iv) Platform buoyancy required to support the weight of equipment in (i), (ii), and (iii).
- (d) You may not include in your transportation allowance:
  - (1) Any of the non-allowable costs listed under § 1206.153(c).
  - (2) Fees paid (either in volume or in value) for actual or theoretical line losses.
  - (3) Any cost as a deduction that duplicates all or part of any other cost that you use under this section.
- (e) Allowable capital costs are those for fixed assets 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) Maintenance
  - (10) Maintenance labor
  - (11) Any other directly allocable and attributable operating expense that you can document
- (g) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense.
- (h) State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(i) To calculate depreciation expense and a return on undepreciated capital costs:

(1) Depreciation and a return on undepreciated capital costs are calculated from the in-service date.

(i) If you or prior owners never claimed an allowance that included depreciation expense and a return from undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset, you may propose an alternative in-service date under (i)(4) of this section.

(ii) The alternative in-service date must not extend beyond the in-service date as extended by the shorter of the useful life and the life of the reserve.

(iii) You may not select the unit-of-production method when applying an alternative in-service date.

(iv) The application of an alternative in-service date does not change the useful life or life of the reserve.

(2) You may elect to use either a straight-line depreciation method or you may elect to use a unit-of-production method to calculate depreciation expense except when the alternative in-service date is applied under paragraph (i)(1)(i) of this section.

(i) Depreciation expense using the straight-line depreciation method is the rate of depreciation from the in-service date through the end of the useful life or life of the reserves under the first-of-month convention.

(ii) Depreciation expense using the units-of-production depreciation method is the product of the rate of depreciation and the units of output produced in the reporting period.

(iii) You may choose to apply these depreciation methods individually to each fixed asset or group of fixed assets.

(iv) 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.

(3) Lessees may include allowable depreciation expense for acquired fixed assets as part of a transportation allowance. If you have a depreciation schedule that the original transporter/lessee established in compliance with 30 CFR part 1206 for purposes of the allowance calculation, a change in ownership of a transportation system will not alter that depreciation schedule.

(4) Proposing a depreciation schedule to ONRR:

(i) If no depreciation schedule under 30 CFR part 1206 exists or has existed for an in-service fixed asset, you may propose to ONRR a depreciation schedule for your transportation allowance.

(ii) If the depreciation schedule for an in-service fixed asset does not comply with 30 CFR part 1206, you may propose to ONRR a depreciation schedule for your transportation allowance.

(iii) ONRR will consider the following factors when reviewing a proposed depreciation schedule for approval:

(A) The lessee's or a prior owner's published capitalization policy, depreciation policy, fixed asset useful life policy, and any related policies in effect during the applicable period, when provided by the proposing lessee;

(B) Consistency with audited financial statements that have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"), when supporting records and reconciliations are provided by the proposing lessee;

(C) Documents prepared in support of the recording and capitalization of fixed assets under U.S. GAAP, when provided by the proposing lessee;

(D) Purchase price allocation reports prepared in accordance with U.S. GAAP by independent experts, when provided by the proposing lessee;

(E) Practices typical of the industry; and

(F) Any information that ONRR deems relevant regarding the depreciation schedule.

(5) You may depreciate a transportation system only once with or without a change in ownership.

(6) To calculate the return on undepreciated capital cost:

(i) You may use an amount equal to the undepreciated capital cost of the transportation system at the beginning of the reporting period multiplied by the rate of return that you determine under paragraph (k) of this section.

(ii) After you have depreciated a transportation system to the reasonable salvage value, you may thereafter include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (k) of this section.

(j) As an alternative to using depreciation expense and a return on undepreciated capital cost, as provided under paragraph (b)(3) of this section, you may use as a cost an amount equal to the allowable initial capital cost of 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.

18. Amend § 1206.159 by revising paragraph (e) as follows:

**§ 1206.159 What general processing allowances requirements apply to me?**

\* \* \* \* \*

(e) ONRR may direct you to modify your processing allowance if:

(1) \* \* \*

(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; 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.

19. Revise and republish § 1206.160 as follows:

**§ 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 § 1206.159(e) 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 and neither you nor your affiliate perform your own processing, you must propose to ONRR a method to determine the processing allowance using the procedures in § 1206.148(a). You may use that method to determine your allowance until ONRR issues its valuation determination.

20. Revise and republish § 1206.161 as follows:

**§ 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) Operating expenses under paragraph (e) of this section.

(2) Overhead under paragraph (f) of this section.

(3) Either:

(i) Depreciation expense and a return on undepreciated capital costs in accordance with paragraph (h)(1) of this section, or

(ii) A cost equal to the initial depreciable capital cost of the processing plant under paragraph (i) of this section.

(iii) Once 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) The reporting period when you do not have an arm's-length processing contract is the reporting month following the production month.

(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 costs are those for fixed assets 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) Maintenance

(10) Maintenance labor

(11) Any other directly allocable and attributable operating expense that you can document

(f) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense.

(g) State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(h) To calculate depreciation expense and a return on undepreciated capital costs:

(1) Depreciation and a return on undepreciated capital costs are calculated from the in-service date.

(i) If you or prior owners never claimed an allowance that included depreciation expense and a return on undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset, you may propose an alternative in-service date under (h)(4) of this section.

(ii) The alternative in-service date must not extend beyond the in-service date as extended by the shorter of the useful life and the life of the reserve.

(iii) You may not select the unit-of-production method when applying an alternative in-service date.

(iv) The application of an alternative in-service date does not change the useful life or life of the reserve.

(2) You may elect to use either a straight-line depreciation method based on the useful life or on the life of the reserves that the processing plant services or you may elect to use a unit-of-production method except when the alternative in-service date is applied under paragraph (h)(1)(i) of this section.

(i) Depreciation expense using the straight-line depreciation method is the rate of depreciation from the in-service date through the end of the useful life or life of the reserves under the first-of-month convention.

(ii) Depreciation expense using the units-of-production depreciation method is the product of the rate of depreciation and the units of output produced in the reporting period.

(iii) You may choose to apply these depreciation methods individually to each fixed asset or group of fixed assets.

(iv) After you make an election, you may not change methods without ONRR's approval. If ONRR approves 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.

(3) Lessees may include allowable depreciation expense for acquired fixed assets as part of a processing allowance. If you have a depreciation schedule that the original processor/lessee established in compliance with 30 CFR part 1206 for purposes of the allowance calculation, a change in ownership of a processing system will not alter the depreciation schedule that the original processor/lessee established for purposes of the allowance calculation.

(4) Proposing a depreciation schedule to ONRR:

(i) If no depreciation schedule under 30 CFR part 1206 exists or has existed for an in-service fixed asset, you may propose to ONRR a depreciation schedule for your processing allowance.

(ii) If the depreciation schedule for an in-service fixed asset does not comply with 30 CFR part 1206, you may propose to ONRR a depreciation schedule for your processing allowance.

(iii) ONRR will consider the following factors when reviewing a proposed depreciation schedule for approval:

(A) The lessee's or a prior owner's published capitalization policy, depreciation policy, fixed asset useful life policy, and any related policies in effect during the applicable period, when provided by the proposing lessee;

(B) Consistency with audited financial statements that have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"), when supporting records and reconciliations are provided by the proposing lessee;

(C) Documents prepared in support of the recording and capitalization of fixed assets under U.S. GAAP, when provided by the proposing lessee;

(D) Purchase price allocation reports prepared in accordance with U.S. GAAP by independent experts, when provided by the proposing lessee;

(E) Practices typical of the industry; and

(F) Any information that ONRR deems relevant regarding the depreciation schedule.

(iv) You may use your proposed depreciation schedule to calculate a transportation allowance beginning with the production month following the month when ONRR received your proposal

until ONRR accepts or rejects it. If ONRR rejects your proposed depreciation schedule, 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.

(5) You may depreciate a processing plant only once with or without a change in ownership.

(6) To calculate a return on undepreciated capital cost, you may use an amount equal to the undepreciated capital cost of the processing plant at the beginning of the reporting period multiplied by the rate of return that you determine under paragraph (j) of this section.

(i) After you have depreciated a processing plant to its reasonable salvage value, you may thereafter include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (j) of this section.

(ii) You may use as a cost an amount equal to the allowable initial cost of the processing plant multiplied by the rate of return determined under paragraph (j) of this section. You may not include depreciation in your allowance.

(j) 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.

(k)

(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.

(l) 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.

21. Revise and republish § 1206.251 as follows:

**§ 1206.251 Definitions.**

The definitions in § 1206.20 do not apply to this subpart. For purposes of this subpart:

*Actual cost* means a cost incurred by a lessee. Actual costs do not include imputed costs, theoretical costs, or avoided costs.

*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.

*Allowance* means a deduction used in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual costs incurred by the lessee for coal washing. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant.

*Alternative in-service date* means the date selected under § 1206.112(i)(1)(i) for Federal oil, § 1206.154(i)(1)(i) or § 1206.161(h)(1)(i) for Federal gas, or § 1206.259(b)(2)(v)(B)(1) or § 1206.262(b)(2)(v)(B)(1) for Federal coal. The term "alternative in-service date" has no meaning outside of the commodities and regulations mentioned.

*Area* means a geographic region in which coal has similar quality and economic characteristics.

Area boundaries are not officially designated and the areas are not necessarily named.

*Arm's-length contract* means:

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

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

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

(iii) Ownership of less than 10 percent creates a presumption of noncontrol which ONRR may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

(2) Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The ONRR may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

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

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

*Capital cost* means the actual cost associated with the initial purchase of a fixed asset with a useful life greater than one year. Non-routine, major overhauls, repairs, maintenance, or upgrades of fixed assets that extend the useful life of the asset or increase its functionality are also capital costs when their economic benefits extend beyond one year. Capital costs include those costs reasonable and necessary to bring the fixed asset to the condition and location of its intended use, such as shipping, delivery, and installation cost. The capital cost of a fixed asset reflects its value when measured at the in-service date.

*Coal* means coal of all ranks from lignite through anthracite.

*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).

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

*Depreciation* means the systematic and rational allocation of the capital cost less a reasonable salvage value of a fixed asset to expense during periods when economic benefits are available to obtain from the fixed asset. Depreciation begins at the in-service date.

*Depreciation schedule* means a document used to record and track depreciation for a fixed asset under 30 CFR part 1206. A depreciation schedule includes a list of fixed assets that can be separately identified. Each fixed asset entry must include the capital cost, the in-service date, the method of depreciation elected, the salvage value, and either the useful life, units of production, or life of reserve. For fixed assets depreciated as a group, the depreciation schedule demonstrates, or allows for the calculation of, either the group's useful life, units of production, or life of the reserve. The depreciation schedule includes, or allows for the calculation of, depreciation expense during the reporting period and the undepreciated capital cost.

*First-of-month convention* means that depreciation begins on the first day of the month of the in-service date or alternative in-service date.

*Fixed assets* means tangible assets owned or controlled by a lessee that are used to produce or provide goods and services in the primary business activities of that entity. Fixed assets have a useful life greater than one year.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing,

screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*In-service date* means the earlier of the date when a fixed asset is placed in service or the date when a fixed asset is functionally ready and available for its intended use. When considering a group of fixed assets, the group in-service date is the in-service date for the primary functional fixed asset of the group.

*Life of the reserve* means the estimated term over which the natural reserve provides an economic benefit. A life of the reserve estimate is based on a report from an unaffiliated or independent expert and clearly identify the assumptions supporting the estimate. If a fixed asset services multiple reserves, the life of the reserve represents the average of the individual reserve life estimates. Life of the reserve is measured in, or is convertible into, months and is determined at or prior to the in-service date.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for a Federal coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

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

*Like-quality coal* means coal that has similar chemical and physical characteristics.

*Marketable condition* means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

*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.

*Net-back method* means a method for calculating market value of coal at the lease or mine.

Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

*Net output* means the quantity of washed coal that a washing plant produces.

*Netting* is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the Form ONRR-4430.

*Operating Expense* means costs associated with the production or provision of goods and services by a business. Operating expenses are costs necessary for the company's normal, core business activities.

*Overhead* means the indirect costs of producing or providing goods and services. Overhead must be systematically and rationally allocated to the goods or services being produced or provided.

Overhead is a cost necessary for the company's normal, core business activities.

*Person* means by individual, firm, corporation, association, partnership, consortium, or joint venture.

*Reserve* means the estimated quantity of known accumulations of a natural resource anticipated to be commercially recoverable from a defined area under existing economic conditions and by established operating practices from a given date forward.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or washing allowance.

*Salvage value* means the value net of disposal costs that the payor expects to realize at the end of the useful life of an asset. Salvage values are designed to minimize any gain or loss at the time of disposal. Salvage value is greater than or equal to zero. Salvage value is determined at or prior to the in-service date.

*Spot market price* means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

*Straight-line depreciation method* means a method of depreciation that allocates capital costs evenly over the useful life of an asset or the life of the reserve. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the useful life of the fixed asset or the life of the reserve.

*Unit-of-production depreciation method* means a method of depreciation that allocates capital cost based on the fixed asset's designed specifications and output parameters. The rate of depreciation applicable to the reporting period under this method is determined by dividing the capital cost by the units of production for which the fixed asset was designed.

*Units of production* means the machine-hours for which an asset was designed to operate or the units of output that an asset was designed to produce. The units of production for a group of fixed assets are the capital-cost-weighted average units of production of the fixed assets comprising the group. Units of production are determined at or prior to the in-service date.

*Useful life* means the term over which the asset provides an economic benefit. If a useful life is applied to a group of fixed assets, it represents the capital-cost-weighted average useful life of the fixed assets comprising the group. Useful life is measured in, or is convertible into, months and is determined at or prior to the in-service date.

22. Revise and republish § 1206.259 as follows:

**§ 1206.259 Determination of washing allowances.**

**(a) *Arm's-length contracts.***

(1) For washing costs incurred by a lessee under an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. ONRR's prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form ONRR-4430.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then the ONRR may require that the washing allowance be determined in accordance with paragraph (b) of this section.

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

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

**(b) *Non-arm's-length or no contract.***

(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form ONRR-4430. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual washing allowance.

(i) The reporting period when you do not have an arm's-length washing contract is the reporting month following the production month.

(ii) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating expenses, overhead, and either depreciation expense and a return on undepreciated capital costs in accordance with paragraph (b)(2)(v) of this section, or a cost equal to the initial capital cost of the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(vi) of this section. Allowable capital costs are those for fixed assets which are an integral part of the wash plant.

(i) Allowable operating expenses include: operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; maintenance;

maintenance labor; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense.

(iii) State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(v) or (b)(2)(vi) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of the ONRR.

(v) To compute depreciation expense:

(A) The lessee may elect to use either a straight-line depreciation method based on the useful life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit-of-production method.

(1) Depreciation expense using the straight-line depreciation method is the rate of depreciation from the in-service date through the end of the useful life or life of the reserves under the first-of-month convention.

(2) Depreciation expense using the units-of-production depreciation method is the product of the rate of depreciation and the units of output produced in the reporting period.

(3) You may choose to apply these depreciation methods individually to each fixed asset or group of fixed assets.

(4) After you make an election, you may not change methods without ONRR's approval. If ONRR approves 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.

(B) Depreciation and a return on undepreciated capital costs are calculated from the in-service date.

(1) If you or prior owners never claimed an allowance that included depreciation expense and a return from undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset, you may propose an alternative in-service date under (b)(2)(v)(D).

(2) The alternative in-service date must not extend beyond the in-service date as extended by the shorter of the useful life and the life of the reserve.

(3) You may not select the unit-of-production method when applying an alternative in-service date.

(4) The application of an alternative in-service date does not change the useful life or life of the reserve.

(C) Lessees may include allowable depreciation expense for acquired fixed assets as part of a washing allowance. If you have a depreciation schedule that the original lessee established in compliance with 30 CFR part 1206 for purposes of the allowance calculation, a change in ownership of a washing system will not alter that depreciation schedule.

(D) Proposing a depreciation schedule to ONRR:

(1) If no depreciation schedule under 30 CFR part 1206 exists or has existed for an in-service fixed asset, you may propose to ONRR a depreciation schedule for your washing allowance.

(2) If the depreciation schedule for an in-service fixed asset does not comply with 30 CFR part 1206, you may propose to ONRR a depreciation schedule for your washing allowance.

(3) ONRR will consider the following factors when reviewing a proposed depreciation schedule for approval: the lessee's or a prior owner's published capitalization policy, depreciation policy, fixed asset useful life policy, and any related policies in effect during the applicable period, when

provided by the proposing lessee; consistency with audited financial statements that have been prepared in accordance with generally accepted accounting principles in the United States (“U.S. GAAP”), when supporting records and reconciliations are provided by the proposing lessee; documents prepared in support of the recording and capitalization of fixed assets under U.S. GAAP, when provided by the proposing lessee; purchase price allocation reports prepared in accordance with U.S. GAAP by independent experts, when provided by the proposing lessee; practices typical of the industry; and any information that ONRR deems relevant regarding the depreciation schedule.

(E) With or without a change in ownership, a wash plant is depreciated only once. Equipment will not be depreciated below a reasonable salvage value.

(F) To calculate the return on undepreciated capital cost, you may use an amount equal to the undepreciated capital cost at the beginning of the reporting period of the washing system multiplied by the rate of return that you determine under paragraph (b)(2)(vii) of this section.

(G) After you have depreciated a washing system to the reasonable salvage value, you may thereafter include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (v) of this section.

(vi) ONRR shall allow as a cost an amount equal to the allowable initial capital cost of the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(vii) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

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

(viii) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) ***Reporting requirements—***

(1) ***Arm's-length contracts.***

(i) The lessee must notify ONRR of an allowance based on incurred costs by using a separate line entry on the Form ONRR-4430.

(ii) ONRR may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

(2) ***Non-arm's-length or no contract.***

(i) The lessee must notify ONRR of an allowance based on the incurred costs by using a separate line entry on the Form ONRR-4430.

(ii) For new washing facilities or arrangements, the lessee's initial washing deduction shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the washing system or, if such data are not available, the lessee shall use estimates based upon industry data for similar washing systems.

(iii) Upon request by ONRR, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by ONRR.

(d) ***Interest and assessments.***

(1) If a lessee nets a washing allowance on the Form ONRR-4430, then the lessee shall be assessed an amount up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this subchapter.

(e) ***Adjustments.***

(1) If the actual coal washing allowance is less than the amount the lessee has taken on Form ONRR-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under § 1218.202 of this subchapter from the date when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual washing allowance is greater than the amount the lessee has taken on Form ONRR-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected Form ONRR-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by ONRR.

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

23. Revise and republish § 1206.262 as follows:

**§ 1206.262 Determination of transportation allowances**

(a) ***Arm's-length contracts.***

(1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form ONRR-4430.

(2) In conducting reviews and audits, ONRR will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then the ONRR may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

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

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

**(b) *Non-arm's-length or no contract.***

(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be

based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form ONRR-4430. When necessary or appropriate, ONRR may direct a lessee to modify its estimated or actual transportation allowance deduction.

(i) The reporting period when you do not have an arm's-length transportation contract is the reporting month following the production month.

(ii) You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating expenses, overhead, and either depreciation expense and a return on undepreciated capital costs in accordance with paragraph (b)(2)(v) of this section, or a cost equal to the initial capital costs of the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(vi) of this section. Allowable capital costs are those for fixed assets which are an integral part of the transportation system.

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

(ii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense.

(iii) State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(v) or (b)(2)(vi) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of ONRR.

(v) To compute depreciation expense:

(A) The lessee may elect to use either a straight-line depreciation method based on the useful life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method.

(1) Depreciation expense using the straight-line depreciation method is the rate of depreciation from the in-service date through the end of the useful life or life of the reserves under the first-of-month convention.

(2) Depreciation expense using the units-of-production depreciation method is the product of the rate of depreciation and the units of output produced in the reporting period.

(3) You may choose to apply these depreciation methods individually to each fixed asset or group of fixed assets.

(4) 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.

(B) Depreciation and a return on undepreciated capital costs are calculated from the in-service date.

(1) If you or prior owners never claimed an allowance that included depreciation expense and a return from undepreciated capital costs or a return on initial undepreciated capital costs for a fixed asset, you may propose an alternative in-service date under (b)(2)(v)(D) of this section.

(2) The alternative in-service date must not extend beyond the in-service date as extended by the shorter of the useful life and the life of the reserve.

(3) You may not select the unit-of-production method when applying an alternative in-service date.

(4) The application of an alternative in-service date does not change the useful life or life of the reserve.

(C) Lessees may include allowable depreciation expense for acquired fixed assets as part of a washing allowance. If you have a depreciation schedule that the original lessee established in compliance with 30 CFR part 1206 for purposes of the allowance calculation, a change in ownership of a transportation system will not alter that depreciation schedule.

(D) Proposing a depreciation schedule to ONRR:

(1) If no depreciation schedule under 30 CFR part 1206 exists or has existed for an in-service fixed asset, you may propose to ONRR a depreciation schedule for your transportation allowance.

(2) If the depreciation schedule for an in-service fixed asset does not comply with 30 CFR part 1206, you may propose to ONRR a depreciation schedule for your washing allowance.

(3) ONRR will consider the following factors when reviewing a proposed depreciation schedule for approval: the lessee's or a prior owner's published capitalization policy, depreciation policy, fixed asset useful life policy, and any related policies in effect during the applicable period, when provided by the proposing lessee; consistency with audited financial statements that have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"), when supporting records and reconciliations are provided by the proposing lessee; documents prepared in support of the recording and capitalization of fixed assets under U.S. GAAP, when provided by the proposing lessee; purchase price allocation reports prepared in

accordance with U.S. GAAP by independent experts, when provided by the proposing lessee; practices typical of the industry; and any information that ONRR deems relevant regarding the depreciation schedule.

(E) With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(F) To calculate the return on undepreciated capital cost, you may use an amount equal to the undepreciated capital cost at the beginning of the reporting period of the transportation system multiplied by the rate of return that you determine under paragraph (b)(2)(vii) of this section.

(G) After you have depreciated a transportation system to the reasonable salvage value, you may thereafter include in the allowance calculation a cost equal to the reasonable salvage value multiplied by a rate of return under paragraph (v) of this section.

(vi) ONRR shall allow as a cost an amount equal to the allowable initial capital cost of the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(vii) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

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

(3) A lessee may apply to ONRR for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (2) of this section. ONRR will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency or by a State regulatory agency (for Federal leases). ONRR shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned

by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, ONRR shall deny the exception request if:

- (i) No Federal or State regulatory agency costs analysis exists and the Federal or State regulatory agency, as applicable, has declined to investigate under ONRR timely objections upon filing; and
- (ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

**(c) *Reporting requirements—***

**(1) *Arm's-length contracts.***

(i) The lessee must notify ONRR of an allowance based on incurred costs by using a separate line entry on the form ONRR-4430.

(ii) ONRR may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by ONRR.

**(2) *Non-arm's-length or no contract.***

(i) The lessee must notify ONRR of an allowance based on the incurred costs by using a separate line entry on Form ONRR-4430.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable coal transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by ONRR, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by ONRR.

(iv) If the lessee is authorized to use its Federal- or State-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

**(d) *Interest and assessments.***

(1) If a lessee nets a transportation allowance on Form ONRR-4430, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with § 1218.202 of this subchapter.

**(e) *Adjustments.***

(1) If the actual coal transportation allowance is less than the amount the lessee has taken on Form ONRR-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under § 1218.202 of this subchapter from the date when the lessee took the deduction to the date the lessee repays the difference to ONRR. If the actual transportation allowance is greater than amount the lessee has taken on Form ONRR-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected Form ONRR-4430 to reflect actual costs, together with any payments, in accordance with instructions provided by ONRR.

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

24. The authority section for part 1290 is revised to read as follows:

Authority: 5 U.S.C. 301 *et seq.*; 30 U.S.C 1724; 43 U.S.C. 1331.

25. Amend § 1290.105 by revising paragraph (f) to read as follows:

**§ 1290.105 How do I appeal an order?**

\* \* \* \* \*

(f) The ONRR Director will review the record that was before the ONRR issuing office along with the written statement of reasons submitted by the appellant and render a decision in the case. The ONRR Director will determine if there is credible evidence to support the Order and shall review all conclusions of law de novo. Such decision will be made in a timely manner and not unreasonably withheld.

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