DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

25 CFR Part 226

[Docket No. BIA–2022–0006; 2231A2100DD/AAKC001030/A0A501010.999900; OMB Control Number 1076–0180, 1012–0004, 1012–0006]

RIN 1076–AF59

Mining of the Osage Mineral Estate for Oil and Gas

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Indian Affairs (BIA) proposes to revise the regulations governing leasing of the Osage Nation's mineral estate (''Osage Mineral Estate'') for oil and gas mining. The proposed rule would allow the BIA to strengthen management of the Osage Mineral Estate by updating bonding, royalty payment and reporting, production valuation and measurement, site security, and operational requirements to address changes in technology and industry standards that have occurred in the 47 years since the regulations were issued. The proposed rule would also allow the BIA to respond to recommendations made by the Office of Inspector General, U.S. Department of the Interior (OIG).

DATES: *Proposed Regulations:* Submit your comments on the proposed rule to the BIA on or before March 17, 2023. *Information Collection Requirements:* Submit your comments on the information collection requirements in the proposed rule on or before March 17, 2023. *Public Meeting:* A public meeting will be held on February 8, 2023, 6:30 p.m. to 9 p.m. central time.

ADDRESSES:

Proposed Regulations: You may submit your comments on the proposed rule by any of the methods listed below.

- *Federal Rulemaking Portal: https://www.regulations.gov.* Enter ''RIN 1076–AF59'' in the search box and click ''Search.'' Follow the instructions for sending comments.
- *Mail:* U.S. Department of the Interior, Eastern Oklahoma Region, Bureau of Indian Affairs, Attn: Regional Director, P.O. Box 8002, Muskogee, OK 74402. All submissions must include the words ''Bureau of Indian Affairs'' or ''BIA'' and ''RIN 1076–AF59.''
- *Hand Delivery/Courier:* U.S. Department of the Interior, Eastern Oklahoma Region, Bureau of Indian Affairs, Attn: Regional Director, 3100 W Peak Boulevard, Muskogee, OK 74402.

Public Meeting: The BIA is holding a public meeting on the Proposed Rule on Wednesday, February 8, 2023, from 6:30 p.m. to 9 p.m. central time at the Osage Casino and Hotel, 5591 W Rogers Boulevard, Skiatook, OK 74070. Please see **SUPPLEMENTARY INFORMATION**, Section II, Public Comment Procedures, for details.

Information Collection Requirements: Comments on the information collection requirements in the proposed rule must be submitted to Steven Mullen, Information Collection Clearance Officer, Office of Regulatory Affairs and Collaborative Action—Indian Affairs, U.S. Department of the Interior, 1001 Indian School Road NW, Suite 229, Albuquerque, NM 87104; or by email to *comments@bia.gov* with a copy to *ONRR_RegulationsMailbox@onrr.gov.* All submissions must include the applicable Office of Management and Budget (OMB) Control Number(s) for the BIA or ONRR information collection(s) you are commenting on:

- OMB Control Number 1076–0180, Mining of the Osage Mineral Estate for Oil and Gas.
- OMB Control Number 1012–0004, Royalty and Production Reporting.
- OMB Control Number 1012–0006, Suspensions Pending Appeal and Bonding.

FOR FURTHER INFORMATION CONTACT: Oliver Whaley, Director, Office of Regulatory Affairs and Collaborative Action, Office of the Assistant Secretary—Indian Affairs, (202) 738–6065, *comments@bia.gov.*

SUPPLEMENTARY INFORMATION:

I. Executive Summary

The purpose of this proposed rule is to amend 25 CFR part 226, Leasing of Osage Reservation Lands for Oil and Gas Mining, to strengthen the Bureau of Indian Affairs' (BIA) management and administration of the Osage Mineral Estate. The last major substantive revisions to the regulations in 25 CFR part 226 occurred in 1974, with many provisions having remained virtually unchanged since well before then. As a result, the regulations are outdated, inconsistent with industry standards, and do not reflect technological advancements or modern oil and gas operations within the Osage Mineral Estate. The BIA believes that the proposed rule updating the regulations makes critical changes that will improve accounting and production measurement standards; offer consistency in production valuation; address inadequate bonding; support the implementation of electronic reporting systems; enhance accountability; clarify lessees' obligations; prevent waste; promote safe and environmentally sound operations; and protect resource values. The BIA also believes that the proposed rule will allow it to take the necessary actions to resolve certain recommendations made by the Office of Inspector General, U.S. Department of the Interior (OIG).

In 2013, the OIG performed an assessment of the BIA Osage Agency's effectiveness in managing the Osage Mineral Estate. On October 20, 2014, the OIG issued its final evaluation report, titled ''BIA Needs Sweeping Changes to Manage the Osage Nation's Energy Resources.'' While the OIG acknowledged the complexity of managing the Osage Mineral Estate due, in part, to the number of competing interests, it documented multiple deficiencies in the BIA Osage Agency's management of the oil and gas program and called for broad reform.

The OIG report set forth 33 recommendations for improvement of the BIA Osage Agency's oil and gas program. The first issue the OIG report addressed was deficiencies in the regulations in 25 CFR part 226. Specifically, the OIG found that the existing regulations are vague, inadequate, and fail to mirror the oil and gas regulations governing the rest of Indian country. Accordingly, the OIG recommended that the BIA ''use its authority to correct program deficiencies by modifying 25 CFR part 226 to mirror other Indian Country oil and gas regulations.'' The OIG also identified issues with accounting, reconciliation, bonding requirements, royalty and production reporting, inspections, lease compliance, and enforcement measures, among other things. The BIA Osage Agency resolved 26 of the OIG's recommendations through the implementation of new and revised policies and procedures but determined that the remaining seven recommendations could not be fully resolved without revision of the regulations in 25 CFR part 226.

This proposed rule modernizes the regulations and brings them in line with the regulations governing oil and gas leasing and development throughout the rest of Indian country consistent with the OIG's recommendation. In addition, the proposed rule will allow the BIA Osage Agency to respond to the open OIG recommendations regarding engagement of the Office of Natural Resources Revenue (ONRR) to perform accounting and compliance activities, implementation of ONRR's electronic reporting systems, reconciliation of royalty payments, verification of allowances and arm's-length sales transactions, and the implementation of sampling thresholds. These revisions are critical to ensure that oil and gas produced from the Osage Mineral Estate is properly accounted for and lessees timely pay the correct and full amount of royalties due to the Osage Nation.

II. Public Comment Procedures

If you wish to comment on this proposed rule, you may submit your comments to the BIA by mail, hand delivery/courier, or through *https://www.regulations.gov* (see **ADDRESSES**). Please make your comments on the proposed rule as specific as possible, provide a detailed explanation of any changes you recommend, and include any relevant supporting documentation. Where possible, your comments should reference the specific section or paragraph of the proposed rule that you are addressing. The BIA is not obligated to consider comments received after the comment period closes (see **DATES**) or comments delivered to an address, or using methods other than, those identified (see **ADDRESSES**).

Comments, including the names and street addresses of respondents, will be available for public review at the BIA Eastern Oklahoma Regional Office, 3100 W Peak Boulevard, Muskogee, OK 74402, during regular business hours (8 a.m. to 4:30 p.m.), Monday through Friday, except holidays. Before including your address, phone number, email address, or other personal identifying information in your comment, please be advised that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask the BIA to withhold your personal identifying information from public review in your comment, we cannot guarantee that we will be able to do so. As discussed in detail below, this proposed rule would include revisions to information collection requirements that must be approved by the Office of Management and Budget (OMB). If you wish to comment on the revised information collection requirements in this proposed rule, you must send such comments directly to the OMB (see **ADDRESSES**).

The BIA is holding a public meeting on the Proposed Rule on Wednesday, February 8, 2023, from 6:30 p.m. to 9 p.m. central time at the Osage Casino and Hotel, 5591 West Rogers Boulevard, Skiatook, OK 74070. At the meeting, you may sign up for a two-minute time slot to provide verbal comments on the Proposed Rule. The BIA requests that groups or organizations wishing to provide verbal comments elect a single representative to speak on behalf of the group or organization.

III. Background

A. Osage Allotment Act

In 1872, the U.S. Congress established a reservation for the Osage Nation in the Oklahoma Territory. On June 16, 1906, Congress passed the Oklahoma Enabling Act, Public Law 59–234, 34 Stat. 256, joining the Oklahoma Territory with Indian Territory to form the state of Oklahoma. Shortly thereafter, Congress passed the Act of June 28, 1906, Public Law 59–321, 34 Stat. 539 (1906 Act), titled an ''Act for the division of the lands and funds of the Osage Indians in Oklahoma Territory.'' The 1906 Act provided for the allotment of the Osage Nation's lands to individual Tribal members. Upon statehood in 1907, the Osage Indian Reservation, comprising approximately 1,475,000 acres, became Osage County, Oklahoma.

Section 3 of the 1906 Act, as amended, severed the surface estate from the subsurface mineral estate, reserving all oil, gas, coal, and other minerals to the Osage Nation in perpetuity. Accordingly, the United States holds the subsurface mineral estate in Osage County, Oklahoma (''Osage Mineral Estate'') in trust for the benefit of the Osage Nation. The 1906 Act authorizes the Osage Nation to lease the Osage Mineral Estate for oil, gas, and other mineral development ''with the approval of the Secretary of the Interior, and under such rules and regulations as he may prescribe.'' The Secretary of the Interior delegated this authority to the Superintendent of the BIA Osage Agency. See 209 Departmental Manual 8.1(A).

Section 4 of the 1906 Act, as amended, required that the United States hold the revenues derived from the Osage Mineral Estate in trust and distribute the funds to individual Tribal members on the authorized roll of membership in a timely (quarterly) and proper (pro rata with interest) basis. This prospective right to share in the royalties, rental, and bonuses derived from the Osage Mineral Estate is referred to as a ''headright.'' See Act of October 30, 1984, Pub. L. 98–605, section 11, 98 Stat. 3163.

B. Osage Tribal Trust Settlement and Negotiated Rulemaking

On October 14, 2011, the United States and Osage Nation signed the Osage Tribal Trust Settlement (Settlement) resolving litigation regarding the United States' alleged mismanagement of the Osage Mineral Estate along with other unrelated breach of trust claims. As part of the Settlement, the Department of the Interior (Department) agreed to engage in negotiated rulemaking with the Osage Nation pursuant to 5 U.S.C. 561–570a and revise the regulations in 25 CFR part 226 to improve management of the Osage Mineral Estate. The negotiated rulemaking process began on June 18, 2012, when the Department published a notice of the intent to establish an Osage Negotiated Rulemaking Committee (Committee). See 77 FR 36226.

On July 31, 2012, the Department announced the establishment of the Committee, comprised of four Federal Government representatives and five members of the Osage Minerals Council who were selected by Council vote. See 77 FR 45301. The Osage Minerals Council representatives on the Committee identified five priority areas to be discussed during negotiations: (1) modernization of royalty value and royalty rate for oil production; (2) modernization of royalty value, royalty rate, and royalty calculations for gas production; (3) strengthening drilling obligations for oil lessees; (4) requiring detailed electronic reporting by all lessees; and (5) strengthening oil gauging and gas meter inspection, calibration, and adjustment.

The Committee held the first public meeting in August 2012 and, except for December 2012, met monthly until April 2013. On April 25, 2013, the Negotiated Rulemaking Committee submitted its Consensus Report to the Department on a package of proposed revisions to the regulations, completing the negotiated rulemaking process required by the Settlement. The Department published the proposed rule based on the Committee's recommendations on August 28, 2013. See 78 FR 53083. The Department received, evaluated, and responded to a significant number of public comments on the proposed rule and amended the regulations to make necessary changes in accordance therewith. On May 11, 2015, the Department published the final rule, which had an effective date of July 10, 2015. See 80 FR 26994.

On July 1, 2015, the Osage Minerals Council and Osage Producers Association each filed suit in the U.S. District Court for the Northern District of Oklahoma (Court), seeking to enjoin implementation of the final rule. The arguments advanced in the lawsuits included, among other things, claims that the final rule conflicted with the 1906 Act, would impose administrative costs that would lead to decreased production, and the Department failed to complete the analyses required by the Regulatory Flexibility and Small Business Regulatory Enforcement Acts. The Court consolidated the two lawsuits and entered an order enjoining implementation of the final rule pending resolution of the litigation.

Upon review of the issues raised in the litigation, the Department determined that a voluntary remand of the final rule was appropriate. The Osage Minerals Council and Osage Producers Association supported such action. On November 19, 2015, the Department filed the Joint Motion for Voluntary Remand and the Court, in turn, entered the Judgment of Remand. As a result of the remand, the 2015 final rule never went into effect. Accordingly, the version of 25 CFR part 226 that was in effect prior to publication of the final rule remained operative. To ensure that the correct version of the regulations appeared in the CFR, the Department published a final rule formally confirming that the prior version of 25 CFR part 226 (last updated in 1974) remained in full force and effect. See 81 FR 39572.

C. Current Rulemaking

Following remand of the 2015 final rule, the BIA determined that it was appropriate to review the regulations in 25 CFR part 226 to consider whether, and to what extent, the regulations should be revised to strengthen the BIA's management and administration of the Osage Mineral Estate. On September 22, 2016, the BIA mailed letters to the Principal Chief of the Osage Nation and Chairman of the Osage Minerals Council requesting government-to-government consultation (consultation) regarding the need for such revisions. On October 25, 2016, the BIA held a consultation with representatives from the Osage Nation Executive and Legislative Branches, the Osage Minerals Council, and their legal counsel, in Pawhuska, Oklahoma. The outcome of the consultation was agreement by all parties that revision of the regulations was necessary. See Section VI, Procedural Matters, for additional information regarding the Tribal consultation process for the proposed rule.

The current effort to revise the regulations in 25 CFR part 226 is not a continuation of the negotiated rulemaking process undertaken pursuant to the Settlement, nor is it a republication of the 2015 final rule.

IV. Incorporation by Reference of Industry Standards

This proposed rule would incorporate industry standards and recommended practices, either in whole or in part, without republishing the standards in their entirety in the CFR. This practice is known as incorporation by reference (IBR). These standards currently apply to all federal and Indian lands except those within Osage County, Oklahoma. The BIA reviewed these standards and determined that they achieve the intent of 25 CFR 226.106 through 226.116 and 25 CFR 226.120 through 226.141 of the proposed rule. The proposed rule proposes to incorporate the versions of the standards listed. Some of the standards referenced would be incorporated in their entirety. For other standards, the BIA would incorporate only those sections that are relevant to the rule, meet the intent of 25 CFR 226.0, and do not require further clarification.

The National Technology Transfer and Advancement Act (NTTAA), Public Law 104–113, 15 U.S.C. 3701, *et seq.,* states that ''all Federal agencies and departments shall use technical standards that are developed by consensus standards bodies, using such technical standards as a means to carry out policy objectives or activities determined by the agencies or departments,'' subject to certain exceptions. The BIA may incorporate these standards into its regulations by reference without republishing the standards in their entirety in the regulations. The legal effect of IBR is that the incorporated standards would become regulatory requirements. The incorporated standards, like any other regulation, have the force and effect of law. Accordingly, lessees and other regulated parties would be required to comply with the standards incorporated by reference in the regulations.

The Office of the Federal Register (OFR) regulations governing IBR are set forth in 1 CFR part 51. The industry standards for this proposed rule are eligible for incorporation pursuant to 1 CFR 51.7 because, among other things, they substantially reduce the volume of material published in the **Federal Register**; are published, bound, numbered, and organized; and are readily available to the public free of charge or through purchase from the standards organization or through inspection at the BIA Osage Agency. The IBR language in § 226.0 meets the requirements set forth in 1 CFR 51.9. Where appropriate, the BIA would incorporate by reference an industry standard governing a particular process and impose requirements that add to, or modify, the requirements imposed by that standard (*e.g.,* the BIA sets a specific value for a variable where the industry standard proposed a range of values or options).

All American Petroleum Institute (API) materials are available for inspection and purchase at the API, 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001, (202) 682–8000. API also offers free, read-only access to the standards in the API IBR Reading Room at *https://publications.api.org.* All American Gas Association (AGA) standards are available for inspection and purchase from AGA, 400 North Capitol Street NW, Suite 450, Washington, DC 20001, (202) 824–7000, *https://www.aga.org/publication-store.* All Gas Processors Association (GPA) standards are available for inspection and purchase from GPA, 6526 E 60th Street, Tulsa, OK 74145, (918) 493–3872, *https://my.midstream association.org/publications-store/ publications.*

The following industry standards and recommendations are proposed for incorporation by reference, in whole or in part, in subpart J of the proposed rule:

- API Manual of Petroleum Measurement Standards (MPMS), Chapter 2—Tank Calibration, Section 2A, Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method; First Edition, February 1995; Reaffirmed 2017 (''API 2.2A''). This standard describes calibration procedures for upright cylindrical tanks used for storing oil.
- API MPMS Chapter 2—Tank Calibration, Section 2B, Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method; First Edition, March 1989; Reaffirmed April 2019; Addendum 1, October 2019 (''API 2.2B''). This standard describes measurement and calibration procedures for determining the diameters of upright welded cylindrical tanks or vertical cylindrical tanks with a smooth surface and either floating or fixed roofs.
- API MPMS Chapter 2—Tank Calibration, Section 2C, Calibration of Upright Cylindrical Tanks Using the Optical-triangulation Method; First Edition, January 2002; Reaffirmed April 2019 (''API 2.2C''). This standard describes a calibration procedure for tanks above 26 feet in diameter with cylindrical courses that are substantially vertical.
- API MPMS Chapter 3.1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products; Third Edition, August 2013; Reaffirmed

December 2018 (''API 3.1A''). This standard describes the: (a) procedures for manually gauging the liquid level of petroleum and petroleum products in non-pressure fixed roof tanks; (b) procedures for manually gauging the level of free water that may be found with the petroleum or petroleum products; (c) methods used to verify the length of gauge tapes under field conditions and the influence of bob weights and temperature on the gauge tape length; and (d) influences that may affect the position of gauging reference point (either the datum plate or the reference gauge point).

- API MPMS Chapter 3—Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging; Third Edition, April 2018 (''API 3.1B''). This standard describes the level measurement of liquid hydrocarbons in stationary, above ground, atmospheric storage tanks using ATGs. This standard also discusses automatic tank gauging in general, including the accuracy, installation, commissioning, calibration, and verification of ATGs that measure either innage or ullage.
- API MPMS Chapter 3—Tank Gauging, Section 6, Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems; First Edition, February 2001; Errata September 2005; Reaffirmed January 2017 (''API 3.6''). This standard describes the selection, installation, commissioning, calibration, and verification of Hybrid Tank Measurement Systems. This standard also provides a method of uncertainty analysis to enable users to select the correct components and configurations to address for the intended application.
- API MPMS Chapter 4—Proving Systems, Section 1, Introduction; Third Edition, February 2005; Reaffirmed June 2014 (''API 4.1''). Section 1 is a general introduction to the subject of proving meters.
- API MPMS Chapter 4—Proving Systems, Section 2—Displacement Provers; Third Edition, September 2003; Reaffirmed March 2011; Addendum February 2015 (''API 4.2''). This standard outlines the essential elements of meter provers that do, and do not, accumulate a minimum of 10,000 whole meter pulses between detector switches and provides design and installation details for the types of displacement provers that are currently in use. The provers discussed in this chapter are designed for proving measurement devices under dynamic operating conditions with single-phase liquid hydrocarbons.
- API MPMS Chapter 4.5, Master-Meter Provers; Fourth Edition, June 2016 (''API 4.5''). This standard covers the use of displacement and Coriolis meters as master meters. The requirements in this standard are for single-phase liquid hydrocarbons.
- API MPMS Chapter 4—Proving Systems, Section 6, Pulse Interpolation; Second Edition, May 1999; Errata April 2007; Reaffirmed October 2013 (''API 4.6''). This standard describes how the double-chronometry method of pulse interpolation, including system operating requirements and equipment testing, is applied to meter proving.
- API MPMS Chapter 4.8, Operation of Proving Systems; Second Edition, September 2013 (''API 4.8''). This standard provides information for operating meter provers on single-phase liquid hydrocarbons.
- API MPMS Chapter 4—Proving Systems, Section 9—Methods of Calibration for Displacement and Volumetric Tank Provers, Part 2—Determination of the Volume of Displacement and Tank Provers by the Waterdraw Method of Calibration; First Edition, December 2005; Reaffirmed July 2015 (''API 4.9.2''). This standard provides all the procedures required to determine the field data necessary to calculate a Base Prover Volume of Displacement Provers by the Waterdraw Method of Calibration.
- API MPMS Chapter 5—Metering, Section 6—Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, October 2002; Reaffirmed November 2013 (''API 5.6''). This standard applies to custody-transfer applications for liquid hydrocarbons and covers the API standards used in the operation of Coriolis meters, proving and verification using volume-based methods, installation, operation, and maintenance.
- API MPMS Chapter 6, Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems; Second Edition, May 1991; Reaffirmed May 2012 (''API 6.1''). This standard describes the design, installation, calibration, and operation of a LACT system.
- API MPMS Chapter 7, Temperature Determination, Section 1—Liquid-in-Glass Thermometers; Second Edition, August 2017 (''API 7.1''). This standard describes how to use various types of liquid-in-glass thermometers to accurately determine the temperatures of hydrocarbon liquids. This standard is proposed for incorporation for its standards covering the use of liquid-in-glass thermometers for temperature determination in tank-gauging operations.
- API MPMS Chapter 7—Temperature Determination, Section 2—Portable Electronic Thermometers; Third Edition, May 2018 (''API 7.2''). This standard describes the methods, equipment, and procedures for manually determining the temperature of liquid petroleum and petroleum products by use of a portable electronic thermometer. This standard is proposed for incorporation for its standards covering the use of portable electronic thermometers for temperature determination in tank gauging operations.
- API MPMS Chapter 7—Temperature Determination, Section 4—Dynamic Temperature Measurement; Second Edition, January 2018 (''API 7.4''). This standard describes methods, equipment, installation, and operating procedures for the proper determination of the temperature of hydrocarbon liquids under dynamic conditions in custody transfer applications. This standard is proposed for incorporation for its standards covering the use of dynamic temperature determination in LACT and CMS operations.
- API MPMS Chapter 8.1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; Fourth Edition, October 2013, (''API 8.1''). This standard covers procedures and equipment for manually obtaining samples of liquid petroleum and petroleum products from the sample point into the primary containers.
- API MPMS Chapter 8.2, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; Fourth Edition, November 2016 (''API 8.2''). This standard describes general procedures and equipment for automatically obtaining samples of liquid petroleum, petroleum products, and crude oils from a sample point into a primary container.
- API MPMS Chapter 8—Sampling, Section 3—Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products; First Edition, October 1995; Reaffirmed, March 2015 (''API 8.3''). This standard covers the handling, mixing, and conditioning procedures required to ensure that a representative sample of the liquid petroleum or petroleum product is delivered from the primary sample container/receiver into the analytical test apparatus or into intermediate containers.
- API MPMS Chapter 9.1, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method; Third Edition, December 2012; Reaffirmed, May 2017 (''API 9.1''). This standard

covers the determination of the density, relative density, or API gravity of crude petroleum, petroleum products, or mixtures of petroleum and non-petroleum products normally handed as liquids have a Reid vapor pressure of 101.325 Kilopascal (kPa) (14.696 psi) or less, using a glass hydrometer in conjunction with a series of calculations.

• API MPMS Chapter 9.2, Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer; Third Edition, December 2012; Reaffirmed, May 2017 (''API 9.2''). This standard covers the determination of the density or relative density of light hydrocarbons including liquefied petroleum gases having a Reid vapor pressure exceeding 101.325 kPa (14.696 psi).

• API MPMS Chapter 9.3, Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method; Third Edition, December 2012; Reaffirmed, May 2017 (''API 9.3''). This standard covers the determination of the density, relative density, or API gravity of crude petroleum, petroleum products, or mixtures of petroleum and non-petroleum products normally handed as liquids and having a Reid vapor pressure of 101.325 kPa (14.696 psi) or less, using a glass thermohydrometer in conjunction with a series of calculations.

• API MPMS Chapter 10.4, Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure); Fourth Edition, October 2013; Errata, March 2015 (''API 10.4''). This standard describes the field centrifuge method for determining both water and sediment, or sediment only, in crude oil.

• API MPMS Chapter 11—Physical Properties Data, Section 1—Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products and Lubricating Oils; May 2004; Addendum 1, September 2007, Addendum 2, May 2019; Reaffirmed, August 2012 (''API 11.1''). This standard provides the algorithm and implementation procedure for the correction of temperature and pressure effects on density and the volume of liquid hydrocarbons that fall within the categories of crude oil.

• API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets; Third Edition, June 2003; Reaffirmed February 2016 (''API 12.2.2''). This standard provides standardized calculation methods for the quantification of liquids and specifies the equations for computing correction factors, rules for rounding, calculation sequences, and discrimination levels to be employed in the calculations.

• API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3—Proving Report; First Edition, October 1998; Reaffirmed May 2014 (''API 12.2.3''). This standard provides standardized calculation methods for the determination of meter factors under defined conditions. The criteria contained in this standard will allow entities using various computer languages on different computer hardware (or by manual calculations) to arrive at identical results using the same standardized input data. This standard also specifies the equations for computing correction factors, including the calculation sequence, discrimination levels, and rules for rounding to be employed in the calculations.

• API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4—Calculation of Base Prover Volumes by the Waterdraw Method; First Edition, December 1997; Errata July 2009; Reaffirmed September 2014 (''API 12.2.4''). This standard provides standardized calculation methods for the quantification of liquids and determination of base prover volumes under defined conditions. The criteria contained in this standard allows individuals, using various computer languages on different computer hardware (or manual calculations), to arrive at identical results using the same standardized input data. This standard specifies the equations for computing correction factors, rules for rounding, the sequence of the calculations, and the discrimination levels of all numbers to be used in these calculations.

• API MPMS Chapter 13.3, Measurement Uncertainty; Second Edition, December 2017 (''API 13.3''). This standard establishes a methodology for developing an uncertainty analysis.

• API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 1, General Equations and Uncertainty Guidelines; Fourth Edition, September 2012; Errata July 2013; Reaffirmed, September 2017 (''API 14.3.1''). This standard provides reference for engineering equations and uncertainty estimations.

• API MPMS Chapter 18—Custody Transfer, Section 1—Measurement Procedures for Crude Oil Gathered from Lease Tanks by Truck; Third Edition, May 2018 (''API 18.1''). This standard describes the procedures, organized into a recommended sequence of steps, for manually determining the quantity and quality of crude oil being transferred under field conditions.

• API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters; First Edition, June 1998; Reaffirmed October 2016 (''API 21.2''). This standard provides for the effective utilization of electronic liquid measurement systems for custody-transfer measurement of liquid hydrocarbons.

• API Recommended Practice (RP) 12R1, Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service; Fifth Edition, August 1997; Reaffirmed April 2008; Addendum 1, December 2017 (''API RP 12R1''). This recommended practice is a guide on new tank installations and the maintenance of existing tanks. Specific provisions from this recommended practice are identified as requirements.

• API RP 2556, Correction Gauge Tables for Incrustation; Second Edition, August 1993; Reaffirmed November 2013 (''API RP 2556''). This recommended practice provides for correcting gauge tables for incrustation applied to tank capacity tables. The tables in this recommended practice show the percent of error of measurement caused by varying thicknesses of uniform incrustation in tanks of various sizes.

The following industry standards and recommendations are proposed for incorporation by reference, in whole or in part, in subpart K of the proposed rule:

• API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer; Seventh Edition, May 2016; Addendum, August 2017; Errata, August 2017 (''API 14.1''). This standard provides comprehensive guidelines for properly collecting, conditioning, and handling representative samples of natural gas that are at or above their hydrocarbon dew point.

• API MPMS, Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 1, General Equations and Uncertainty Guidelines; Fourth Edition, September 2012; Errata, July 2013 (''API 14.3.1''). This standard provides engineering equations and uncertainty estimations for the calculation of flow rate through concentric, square-edge, flange-tapped orifice meters.

• API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 2, Specification and Installation Requirements; Fifth Edition, March 2016; Errata 1, March 2017; Errata 2, January 2019) (''API 14.3.2''). This standard provides construction and installation requirements, and standardized implementation recommendations, for the calculation of flow rate through concentric, square-edge, flange-tapped orifice meters.

• API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 3, Natural Gas Applications; Fourth Edition, November 2013 (''API 14.3.3''). This standard is an application guide for the calculation of natural gas flow through a flange-tapped, concentric orifice meter.

• API MPMS, Chapter 14.5, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; Reaffirmed November 2020 (''API 14.5''). This standard presents procedures for calculating the following properties of natural gas mixtures at base conditions from composition: gross heating value, relative density (real and ideal), compressibility factor, and theoretical hydrocarbon liquid content.

• API MPMS Chapter 21.1, Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement; Second Edition, February 2013 (''API 21.1''). This standard describes the minimum specifications for electronic gas measurement systems (EGMs) used in the measurement and recording of flow parameters of gaseous phase hydrocarbon and other related fluids for custody transfer applications utilizing industry recognized primary measurement devices.

• AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids; Second Edition, September 1985 (''AGA Report No. 3''). This report provides construction and installation requirements, and standardized implementation recommendations, for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.

• AGA Transmission Measurement Committee Report No. 8, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases; Second Edition, November 1992 (''AGA Report No. 8''). This report presents detailed information for precise computations of compressibility factors and densities of natural gas and other hydrocarbon gases, calculation uncertainty estimations, and FORTRAN computer program listings.

• GPA Midstream Standard 2166–17, Obtaining Natural Gas Samples for Analysis by Gas Chromatography, Reaffirmed 2017 (''GPA 2166–17''). This standard recommends procedures for obtaining samples from flowing natural gas streams that represent the compositions of the vapor phase portion of the system being analyzed.

• GPA Standard Midstream 2261–19, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography; Revised 2019 (''GPA 2261–19''). This standard establishes a method to determine the chemical composition of natural gas and similar gaseous mixtures within set ranges using a gas chromatograph (CG).

• GPA Midstream Standard 2198–16, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends; Revised 2016 (''GPA 2198–16''). This standard establishes procedures for selecting the proper natural gas and natural gas liquids reference standards, preparing the reference standards for use, verifying the accuracy of composition as reported by the manufacturer, and the proper care and storage of those reference standards to ensure their integrity while they are in use.

V. Discussion of Proposed Changes

This proposed rule adds new sections and redesignates or revises current sections as set forth in the table below. The proposed rule removes all references to the ''Osage Tribal Council,'' and replaces them with ''Osage Nation'' or ''Osage Minerals Council,'' as applicable, because the Osage Tribal Council ceased to exist upon ratification of the Constitution of the Osage Nation in 2006.

New section	Current section	Proposed changes
226.0	N/A	The proposed rule identifies the API standards incorporated by reference in subpart J, Oil Measurement, and the API, AGA, and GPA standards incorporated by reference in subpart K, Gas Measurement.
226.1	226.1	The proposed rule defines new key terms, updates existing definitions, and removes definitions of terms that are no longer used in the regulations.
226.2 (new)	N/A	The proposed rule identifies the legal authorities that govern oil and gas leasing and development activities within the Osage Mineral Estate.
226.3 (new)	N/A	The proposed rule describes the Superintendent's authority and responsibility to administer oil and gas leasing and development of the Osage Mineral Estate.
226.4 (new)	N/A	The proposed rule describes ONRR's authority and responsibility to administer the Osage royalty management program.
226.5	226.45	The proposed rule clarifies the Superintendent's authority to issue orders and notices and adds a provision specifying ONRR's authority to issue orders and notices.
226.6	226.31	The proposed rule removes the provision requiring lessees who reside outside the state of Oklahoma to designate in-state process agents for the purpose of serving notice. The proposed rule also removes the provision providing for the Superintendent to serve notice on employees present on the lease if the designated process agent is incapacitated or absent from the state of Oklahoma. The proposed rule adds provisions setting forth the procedures the Superintendent and ONRR will use to serve official correspondence.
226.7	226.7	No substantive change.
226.8	226.4	The proposed rule removes the language allowing cash payments and updates the accepted forms of payment to include electronic funds transfer (EFT), certified check, cashier's check, money order, or commercial or personal check drawn on a solvent bank.

New section	Current section	Proposed changes
226.9	226.2(c)	The proposed rule clarifies the Superintendent's obligations to conduct environmental reviews and cultural surveys prior to approving leases and operations involving new or additional ground-disturbance.
226.10	226.46	The proposed rule updates this section to reflect amendments to the Paperwork Reduction Act promulgated after the section was last revised requiring the BIA to obtain OMB approval for the information collections in 25 CFR part 226. The proposed rule also adds language identifying the applicable OMB Control Numbers.
226.11 (new)	N/A	The proposed rule informs submitters of information that the BIA and ONRR will make records available to the public without prior notification, subject to exceptions for trade secrets, confidential commercial or financial information, and information protected by the Privacy Act.
226.12	226.2(f)	The proposed rule clarifies that the OMC must submit requests for the Superintendent to negotiate leases in writing and provide a resolution authorizing such negotiation. This change reflects the BIA's and OMC's existing practices for the submission of leasing requests.
226.13	226.2(f)	The proposed rule clarifies that the OMC must submit requests for the Superintendent to advertise lease sales in writing and provide a resolution authorizing such advertising. This change reflects the BIA's and OMC's existing practices for the submission of lease sale requests.
226.14	226.2(a)	The proposed rule removes the nomination fee for lease sales and clarifies the content and submission requirements for lease sale nominations. These clarifications reflect the BIA's existing requirements for lease sale nominations.
226.15	226.2(b)	The proposed rule specifies that the Superintendent will publish the Notice of Lease Sale at least 30 calendar days prior to the date of the sale. This change reflects the BIA's and OMC's existing practices for publishing such notices.
226.16	226.2(b), 226.6(a)	The proposed rule specifies that successful bidders must submit 25 percent of the bonus by 4:30 p.m. central standard time on the day of the sale. The proposed rule also removes the language allowing cash payments and updates the accepted forms of payment to electronic funds transfer (EFT), cashier's check, or money order.
226.17	226.2(b)	No substantive change.
226.18	226.2(f)	The proposed rule specifies what information offerors must include in non-competitive lease offers submitted to the OMC.
226.19	226.6(a)	The proposed rule requires successful offerors of non-competitive leases to submit the bonus and required documentation to the Superintendent within 20 calendar days of the OMC's acceptance of the offer. This change reflects the BIA's and OMC's existing requirements for non-competitive leases and is consistent with the requirements for competitive leases in the new § 226.16.
226.20	226.2(d)	The proposed rule removes oil-only and gas-only leases and requires all leases executed after the effective date of the final rule to be combination oil and gas leases.
226.21	226.9(b), 226.10	The proposed rule combines the regulations regarding extension of the primary term and the term of the lease into one section. The proposed rule specifies the actions that constitute "actual drilling operations" for purposes of obtaining an extension of the primary term.
226.22	226.5	No substantive change.
226.23	226.2(e)	The proposed rule clarifies the prohibition on U.S. Government employees acquiring interests in leases of the Osage Mineral Estate.
226.24	226.15(a)	The proposed rule specifies that lessees must submit cooperative agreements to the Superintendent for approval at least 90 calendar days prior to expiration of the leases covered by the agreements.
226.25	226.15(a)	No substantive change.
226.26	226.15(b)	No substantive change.
226.27	226.15(b)	No substantive change.
226.28 (new)	N/A	The proposed rule specifies the effective date of the transfer for lease assignments.
226.29 (new)	N/A	The proposed rule specifies that assignors are liable for lease obligations and compliance issues that accrue prior to approval of the assignment.
226.30 (new)	N/A	The proposed rule specifies that assignees are liable for lease obligations and compliance issues that accrue after approval of the assignment.
226.31	226.15(c)	No substantive change.
226.32	226.15(d)	The proposed rule removes the provision authorizing the Superintendent to approve drilling contracts because it is contrary to law and clarifies that lessees are simply required to file copies of drilling contracts with the Superintendent.
226.33	226.3	No substantive change.
226.34	226.9(a), 226.29(a)	The proposed rule combines the regulations regarding lease termination and lessees' obligations upon termination into one section. The proposed rule adds a provision specifying that leases in the extended term terminate by operation of law as of the date production in paying quantities ceases. The provision regarding termination in the extended term reflects the BIA's existing practices.
226.35	226.9(a)	The proposed rule increases the rental rate for leases approved after the effective date of the final rule. The proposed rule also requires lessees to pay advance annual rental for the full primary term within 15 calendar days of the Superintendent's approval of the lease.

New section	Current section	Proposed changes
226.36	226.11(a)(1)	The proposed rule removes the language requiring a royalty rate of not less than 20 percent when the quantity of oil from all wells in a quarter-section or fraction thereof during any calendar month averages 100 bbl or greater per well, per day. The proposed rule adds language authorizing the Superintendent to approve an oil royalty rate that is below the minimum royalty rate in the regulations if it is determined to be in the best interest of the Osage Nation.
226.37	226.11(a)(2)	The proposed rule requires the value of oil to be calculated using the NYMEX Calendar Month Average Price of oil at Cushing, Oklahoma instead of the highest posted price by a major purchaser in Osage County, Oklahoma.
226.38 (new)	N/A	The proposed rule specifies how to calculate the gravity adjustment of the NYMEX Calendar Month Average Price of oil.
226.39	226.11(b)	The proposed rule adds language authorizing the Superintendent to approve a gas royalty rate that is below the minimum royalty rate in the regulations if it is determined to be in the best interest of the Osage Nation.
226.40	226.11(b)	The proposed rule requires the value of gas to be calculated using the ONRR Monthly Index Zone Price for Oklahoma Zone 1 instead of the market value of the gas and products extracted therefrom.
226.41	226.11(c)	The proposed rule requires lessees to submit minimum royalty payments to ONRR instead of the Superintendent.
226.42	226.11(a)(3)	The proposed rule revises the royalty-in-kind provision to allow the OMC to take both oil and gas royalty-in-kind and adds a provision setting forth notice requirements for the OMC initiating and terminating royalty-in-kind status.
226.43	226.13(a) and (c)	The proposed rule requires lessees and purchasers to submit royalty payments to ONRR instead of the Superintendent and establishes a new due date for royalty payments. The proposed rule also adds a provision specifying the procedure for payors to recoup overpayments.
226.44	226.14	The proposed rule removes the language requiring the Superintendent's approval of royalty payment contracts and division orders and clarifies that lessees are simply required to file such contracts and division orders with the Superintendent prior to removing production from the lease.
226.45	226.13(b)	The proposed rule requires lessees to submit royalty reports to ONRR electronically, subject to certain exceptions, and establishes a new due date for reporting.
226.46	226.30	The proposed rule requires lessees to retain rental, royalty, and payment records for a minimum of six years unless the Superintendent or ONRR direct otherwise. The proposed rule also adds a provision requiring lessees to make such records available to ONRR upon request.
226.47	226.12	The proposed rule updates this section by requiring the U.S. Government to purchase oil produced from the Osage Mineral Estate at the price set forth in § 226.37.
226.48 (new)	N/A	The proposed rule authorizes ONRR to conduct audits and reviews of compliance with rental, royalty, and other payment and reporting requirements.
226.49 (new)	N/A	The proposed rule exempts existing lease (quarter-section) and collective bonds from certain changes to the bonding requirements.
226.50	226.6	The proposed rule adds a provision identifying the accepted types of performance bonds.
226.51	226.6(a) and (c)	The proposed rule replaces the $5,000 lease bond for each quarter-section or fraction thereof covered by the lease with an individual well bond of $6 per foot of measured or projected well depth.
226.52	226.6(a) and (b)	The proposed rule combines the collective and nationwide bond provisions into one section. The proposed rule changes the collective bond (covering all leases up to 10,240 acres) to a countywide bond covering only those operations in Osage County up to 10,240 acres and increases the bond amount from $50,000 to $75,000.
226.53	226.6(d)	The proposed rule clarifies the conditions that justify the Superintendent increasing the required bond amount and adds a provision placing a limit on the amount of any such increase.
226.54 (new)	N/A	The proposed rule specifies that the Superintendent has authority to call for the forfeiture of performance bonds and clarifies lessees' obligations upon default. This change reflects the Superintendent's existing authority, as all bonds are payable to the Superintendent. The proposed rule adds a provision specifying that the United States or OMC may take action to recover from lessees all costs in excess of the amount collected under the bond if an obligation in default exceeds the face amount of the bond.
226.55 (new)	N/A	The proposed rule specifies that the period of liability under a performance bond will not terminate, and the bond will not be released, until all lease obligations have been satisfied. This reflects the BIA's existing practices for the release of bonds.
226.56 (new)	N/A	The proposed rule requires bonding for geophysical exploration activities, subject to certain exceptions for existing lessees.
226.57 (new)	N/A	The proposed rule specifies that the Superintendent has authority to call for the forfeiture of geophysical exploration bonds. This is consistent with the Superintendent's authority for performance bonds for all other oil and gas operations within the Osage Mineral Estate.

New section	Current section	Proposed changes
226.58 (new)	N/A	The proposed rule specifies that the period of liability under a geophysical exploration bond will not terminate, and the bond will not be released, until all permit obligations have been satisfied. This is consistent with the BIA's existing practices for the release of performance bonds for all other oil and gas operations within the Osage Mineral Estate.
226.59	226.19(a)	The proposed rule adds a provision requiring lessees and permittees to properly maintain installations and equipment and comply with the National Electrical Code.
226.60	226.30	The proposed rule clarifies the Superintendent's authority to inspect and investigate operations.
226.61	226.16(a)	The proposed rule clarifies the language regarding the commencement of operations, expressly stating that operations may not commence until the Superintendent approves a lease or geophysical exploration permit, as applicable.
226.62	226.17	No substantive change.
226.63	226.18	The proposed rule adds a provision requiring lessees and permittees to send meeting requests to surface owners by certified mail. The proposed rule also adds a provision authorizing the Superintendent to approve the commencement of operations if a meeting request cannot be delivered to the surface owner's last known address or the surface owner fails to accept the request within 30 calendar days of receiving it.
226.64	226.19(b) through (d)	The proposed rule combines the regulations regarding commencement money for operations and tank siting fees into one section. The proposed rule increases the amount of commencement money for drilling and reentering wells and siting tanks and adds a provision requiring lessees and permittees to pay commencement money for the acreage occupied during seismic surveys using vibroseis. The proposed rule also adds a provision stating that commencement money that cannot be delivered to the surface owner's last known address or that the surface owner refuses is deemed forfeited.
226.65	226.19(a), 226.24	The proposed rule combines the regulations regarding the use of surface lands and water into one section. No substantive changes.
226.66	226.16(b)(1) and (c); 226.33.	The proposed rule combines the regulations regarding drilling operations and line drilling requirements into one section. The proposed rule specifies that lessees must provide the Superintendent with five calendar days' notice of drilling operations. The proposed rule adds a line drilling requirement imposing a setback from certain water sources. This setback is consistent with the BIA's existing permit conditions under the Osage County Oil and Gas Final Environmental Impact Statement (2020).
226.67	226.36	The proposed rule requires lessees to obtain the Superintendent's prior approval to drill wells that deviate significantly from the vertical and conduct directional surveys if deviation occurs without prior approval.
226.68	226.40	No substantive change.
226.69	226.16(b)(1) and (2), (c);	The proposed rule specifies that lessees must provide the Superintendent with at least five calendar days' notice of workover operations. The proposed rule adds a provision clarifying that prior approval and a subsequent report of operations are not required for certain well maintenance activities. This change reflects the BIA's existing practices with respect to well maintenance activities.
226.70 (new)	N/A	The proposed rule establishes testing, training, operational, and safety requirements for drilling and workover operations in Hydrogen Sulfide (H_2S) areas.
226.71	226.32(b), (d)	The proposed rule adds a provision requiring lessees to conduct reasonable tests of the mechanical integrity of downhole equipment.
226.72	226.28(a)	The proposed rule clarifies the language regarding temporary abandonment, more clearly stating that lessees must obtain the Superintendent's approval to temporarily abandon a well for more than 30 calendar days.
226.73	226.28(a) and (b); 226.29(c) and (d).	The proposed rule combines the regulations regarding permanent abandonment and plugging obligations into one section. The proposed rule removes the plugging application fee and requirement that oil-only and gas-only lessees offer wells to one another prior to abandonment. The proposed rule specifies that lessees must provide the Superintendent with five calendar days' notice of plugging operations.
226.74	226.32(a), (c), and (e)	The proposed rule requires lessees to submit certain information together with the subsequent report of hydraulic fracturing operations and adds a provision specifying the procedure for lessees to withhold confidential information regarding such operations. The proposed rule also clarifies that lessees must retain well records and reports for a minimum of six years unless the Superintendent directs otherwise.
226.75	226.34	The proposed rule adds a provision requiring lessees to mark wells that are permanently plugged and abandoned.
226.76	226.22(a), 226.35	The proposed rule combines the regulations regarding the prevention of pollution and protection of formations into one section. The proposed rule specifies that lessees and permittees must conduct surveys and tests of the measures taken to protect fresh water and mineral bearing formations and provide the results to the Superintendent upon request.

New section	Current section	Proposed changes
226.77	226.22(b) through (e)	The proposed rule adds provisions prohibiting lessees from constructing pits in certain sensitive locations consistent with the BIA's existing permit conditions under the Osage County Oil and Gas Final Environmental Impact Statement (2020). The proposed rule also adds a provision requiring the Superintendent's prior approval for the land application of drilling fluids.
226.78 (new)	N/A	The proposed rule requires lessees to remove fire hazards from well sites and facilities and safely dispose of waste oil. These requirements are consistent with the BIA's existing permit conditions under the Osage County Oil and Gas Final Environmental Impact Statement (2020).
226.79 (new)	N/A	The proposed rule requires a geophysical exploration permit to conduct geophysical exploration operations on both leased and unleased lands.
226.80 (new)	N/A	The proposed rule specifies that lessees and permittees must provide the Superintendent with five calendar days' notice of geophysical exploration operations.
226.81 (new)	N/A	The proposed rule requires lessees and permittees to submit subsequent reports of geophysical exploration operations to the Superintendent.
226.82	226.20	No substantive change.
226.83	226.21	No substantive change.
226.84	226.9(a)	The proposed rule specifies that lessees must place oil and gas into marketable condition at no cost to the lessor. This change is consistent with current industry practices within the Osage Mineral Estate.
226.85	226.13(b)	The proposed rule requires lessees to submit production reports to ONRR electronically, subject to certain exceptions, and establishes a new due date for production reports.
226.86 (new)	N/A	The proposed rule requires lessees to submit site facility diagrams to the Superintendent and specifies the format and content of such diagrams.
226.87 (new)	N/A	The proposed rule requires lessees to use FMP numbers when reporting production to ONRR.
226.88 (new)	N/A	The proposed rule specifies what information production records must contain and requires lessees to maintain such records for a minimum of six years unless the Superintendent or ONRR direct otherwise. The proposed rule also requires lessees, purchasers, and transporters to provide production records to ONRR upon request.
226.89	226.23	No substantive change.
226.90	226.37	No substantive change.
226.91 (new)	N/A	The proposed rule requires lessees to pay compensatory royalty for avoidably lost or wasted production. This change reflects the BIA's existing requirement to pay royalty for lost and wasted production. The proposed rule specifies when production is considered avoidably and unavoidably lost or wasted.
226.92 (new)	N/A	The proposed rule sets forth lessees' responsibilities for protecting oil and gas resources from drainage.
226.93 (new)	N/A	The proposed rule requires lessees to pay compensatory royalty for drainage if protective action is not taken within a reasonable time and specifies how compensatory royalty will be calculated.
226.94 (new)	N/A	The proposed rule requires the use of seals on appropriate valves at oil storage and sales facilities and prohibits tampering with such valves.
226.95 (new)	N/A	The proposed rule requires the use of seals on oil measurement system components.
226.96 (new)	N/A	The proposed rule requires transporters removing oil from storage tanks to possess run tickets, trip logs, and manifests.
226.97 (new)	N/A	The proposed rule requires any person transporting oil or gas to possess documentation indicating the first purchaser and authorizes the Superintendent and law enforcement to conduct vehicle inspections.
226.98 (new)	N/A	The proposed rule requires lessees, purchasers, and transporters to record certain information when water is drained from tanks holding oil.
226.99 (new)	N/A	The proposed rule requires lessees to record certain information when oil is removed from storage and used on the lease or unit for hot oiling, clean up, and completion operations. The proposed rule also requires lessees to report all production removed from storage and used on a different lease to ONRR.
226.100 (new)	N/A	The proposed rule specifies the records that lessees must maintain for each seal.
226.101 (new)	N/A	The proposed rule requires lessees to obtain the Superintendent's approval for off-lease measurement of production.
226.102	226.41	The proposed rule specifies that lessees must report spills, thefts, mishandling of production, accidents, and fires to both the Superintendent and surface owners immediately upon discovery and requires lessees to submit incident reports with proposed contingency or remediation plans to the Superintendent. This change reflects the BIA's current requirements for reporting of such incidents. The proposed rule adds a provision requiring lessees to provide surface owners with both emergency and written notification of such incidents.
226.103 (new)	N/A	The proposed rule prohibits bypasses of meters and tampering with oil measurement devices, the components of such devices, and the measurement process and imposes the maximum penalty for such violations.
226.104 (new)	N/A	The proposed rule establishes the timeframe for complying with the new requirements for oil measurement equipment and procedures.
226.105	N/A	[Reserved]

New section	Current section	Proposed changes
226.106 (new)	N/A	The proposed rule establishes requirements for oil volume uncertainty levels, measurement bias, and equipment verification.
226.107	226.38	The proposed rule specifies that tank gauging may be used to measure oil and updates requirements for the use and calibration of oil storage tanks.
226.108	226.38	The proposed rule specifies the required tank gauging procedures.
226.109	226.38	The proposed rule specifies that Lease Automatic Custody Transfer (LACT) systems may be used to measure oil and sets forth general requirements for LACT systems.
226.110	226.38	The proposed rule identifies required LACT system equipment and sets forth standards for operating LACT system components.
226.111	226.38	The proposed rule specifies that Coriolis Measurement Systems (CMS) may be used to measure oil and sets forth general requirements for CMS and CMS components.
226.112	226.38	The proposed rule establishes Coriolis meter operating requirements.
226.113 (new)	N/A	The proposed rule sets forth requirements for volumetric meter proving.
226.114 (new)	N/A	The proposed rule requires the completion and submission of run tickets for tank gauging, LACT systems, and CMS. This change codifies the BIA's existing requirements with respect to run tickets.
226.115	226.38	The proposed rule specifies that the Superintendent's approval is required to use methods of oil measurement other than tank gauging, LACT system, or CMS.
226.116 (new)	N/A	The proposed rule prohibits the sale and disposal of waste oil without the Superintendent's approval. This change codifies the BIA's existing requirement.
226.117 (new)	N/A	The proposed rule prohibits bypasses of meters. The proposed rule also prohibits tampering with any measurement device, component of a measurement device, or the measurement process. The proposed rule imposes the maximum penalty for such violations.
226.118 (new)	N/A	The proposed rule establishes the timeframe for complying with the new requirements for gas measurement equipment and procedures.
226.119	N/A	[Reserved]
226.120 (new)	N/A	The proposed rule establishes requirements for gas flow rate and heating value uncertainty, measurement bias, and equipment verification.
226.121	226.39	The proposed rule specifies the standards for orifice plates and meter tubes and sets forth inspection requirements.
226.122	226.39	The proposed rule establishes standards for the use of mechanical recorders.
226.123 (new)	N/A	The proposed rule establishes requirements for the verification and calibration of mechanical recorders, correction of reported gas volumes, and certification of test equipment.
226.124 (new)	N/A	The proposed rule specifies what information integration statements must contain and requires lessees to retain integration statements.
226.125	226.39	The proposed rule establishes standards for the use of electronic gas measurement (EGM) systems.
226.126 (new)	N/A	The proposed rule establishes requirements for the verification and calibration of transducers, correction of reported gas volumes, and certification of test equipment.
226.127 (new)	N/A	The proposed rule provides the gas flow rate, volume, and average value calculations.
226.128 (new)	N/A	The proposed rule requires lessees to retain certain logs and records and make them available to the Superintendent upon request.
226.129 (new)	N/A	The proposed rule specifies the methods of gas sampling and analysis that may be used.
226.130 (new)	N/A	The proposed rule establishes standards for the location, design, and type of sampling probes and sample tubing size.
226.131 (new)	N/A	The proposed rule establishes the general requirements for taking spot samples.
226.132 (new)	N/A	The proposed rule specifies the methods of spot sampling that may be used.
226.133 (new)	N/A	The proposed rule specifies the frequency with which lessees must take and analyze spot samples.
226.134 (new)	N/A	The proposed rule establishes specifications for composite sampling methods.
226.135 (new)	N/A	The proposed rule establishes requirements for the installation, operation, verification, and calibration of on-line gas chromatographs.
226.136 (new)	N/A	The proposed rule establishes requirements for the installation, operation, verification, and calibration of gas chromatographs.
226.137 (new)	N/A	The proposed rule identifies the components of gas that must be analyzed and the frequency with which component analysis must occur.
226.138 (new)	N/A	The proposed rule specifies what information gas analysis reports must contain.
226.139 (new)	N/A	The proposed rule specifies the effective date of a spot or composite gas sample.
226.140 (new)	N/A	The proposed rule establishes requirements for calculating the heating value, average heating value, and volume of a gas sample.
226.141 (new)	N/A	The proposed rule establishes requirements for reporting gross and real heating values and volumes.
226.142	226.27(b)	The proposed rule updates the provision by requiring the Osage Nation and Tribal members to pay for gas at the price set forth in § 226.40.
226.143	226.27(b)	The proposed rule updates the provision by requiring the lessee to pay royalty on all gas furnished to the Osage Nation and Tribal members at the rate set forth in § 226.39.

New section	Current section	Proposed changes
226.144	226.11(a)(1) and (b)(2)	No substantive change.
226.145 (new)	N/A	The proposed rule identifies the uses of production on a lease or unit that do not require the Superintendent's prior approval for royalty-free treatment.
226.146 (new)	N/A	The proposed rule identifies the uses of production on a lease or unit that require the Superintendent's prior approval for royalty-free treatment.
226.147 (new)	N/A	The proposed rule identifies the uses of production off the lease or unit that do not require the Superintendent's prior approval of royalty-free treatment.
226.148 (new)	N/A	The proposed rule identifies the uses of production off the lease or unit that require the Superintendent's prior approval of royalty-free treatment.
226.149 (new)	N/A	The proposed rule sets forth requirements for the measurement and reporting of royalty-free volumes of oil and gas used.
226.150 (new)	N/A	The proposed rule specifies that lessees do not need to own or lease the equipment or facility that uses royalty-free oil and gas.
226.151 (new)	N/A	The proposed rule sets forth procedures for requesting royalty-free use of oil and gas.
226.152	226.37	The proposed rule adds a provision prohibiting the venting and flaring of gas without the Superintendent's prior approval. The proposed rule also requires all flares and combustible devices to be equipped with an automatic ignition system. This reflects the BIA's existing requirements for venting and flaring and is consistent with the BIA's existing permit conditions under the Osage County Oil and Gas Final Environmental Impact Statement (2020).
226.153 (new)	N/A	The proposed rule adds a provision prohibiting the venting and flaring of gas-well gas unless it is unavoidably lost.
226.154 (new)	N/A	The proposed rule authorizes the venting and flaring of oil-well gas in accordance with §§ 226.155, 226.156, and 226.157.
226.155 (new)	N/A	The proposed rule requires gas to be flared, rather than vented, subject to certain exceptions.
226.156 (new)	N/A	The proposed rule authorizes the venting and flaring of gas during certain tests, well maintenance activities, and emergencies.
226.157 (new)	N/A	The proposed rule sets forth the requirements for measuring and reporting the volumes of gas vented and flared.
226.158	226.42	The proposed rule identifies the remedies the Superintendent may utilize to address violations of lease or permit terms and conditions, the regulations, and orders or notices.
226.159	226.43	The proposed rule updates the list of lease operation violations that will result in immediate assessments.
226.160 (new)	N/A	The proposed rule authorizes the Superintendent to issue assessments if a lessee fails to commence or perform an operation within five calendar days of an order to do so if the Superintendent performs the operation or must retain a third-party to perform the operation.
226.161 (new)	N/A	The proposed rule sets forth the procedure the Superintendent will use to notify lessees of lease violations that have a period to correct prior to the assessment of penalties and the penalty amounts imposed if violations are not timely corrected.
226.162 (new)	N/A	The proposed rule sets forth the procedure the Superintendent will use to notify lessees of lease violations that do not have a period to correct prior to the assessment of penalties and the penalty amounts imposed for such violations.
226.163 (new)	N/A	The proposed rule specifies the factors the Superintendent will consider in determining that amount of the penalty to assess.
226.164	226.28(c)	The proposed rule clarifies the circumstances under which the Superintendent may take shut-in action.
226.165	226.29(b); 226.42	The proposed rule specifies the circumstances under which the Superintendent may cancel a lease or permit and the procedure for cancelling a lease or permit.
226.166	226.42	The proposed rule specifies that interest on unpaid and underpaid civil penalties and assessments will be charged at the IRS underpayment rate or such other rate as the Superintendent may prescribe.
226.167 (new)	N/A	The proposed rule identifies the remedies ONRR may utilize to address violations of lease or permit terms and conditions, the regulations, and orders or notices.
226.168 (new)	N/A	The proposed rule authorizes ONRR to issue assessments for incorrect or late royalty and production reporting and specifies the amount of such assessments.
226.169 (new)	N/A	The proposed rule authorizes ONRR to issue assessments for failing to submit the correct payment amount or providing inadequate or erroneous information and specifies the amounts of such assessments.
226.170 (new)	N/A	The proposed rule sets forth the procedure ONRR will use to notify reporters and payors of violations that have a period to correct prior to the assessment of penalties and the penalty amounts imposed if violations are not timely corrected.
226.171 (new)	N/A	The proposed rule sets forth the procedure ONRR will use to notify reporters and payors of violations that do not have a period to correct prior to the assessment of penalties and the penalty amounts imposed.
226.172 (new)	N/A	The proposed rule specifies the factors ONRR will consider in determining the amount of the penalty to assess.
226.173 (new)	N/A	The proposed rule specifies the due date for remitting payment of penalties and assessments to ONRR and that interest on unpaid and underpaid penalty and assessment amounts will be charged at the rate set forth in § 226.166(b).

New section	Current section	Proposed changes
226.174 (new)	N/A	The proposed rule specifies the actions ONRR may take to collect unpaid civil penalties.
226.175 (new)	N/A	The proposed rule specifies that ONRR will refer past due debts to the U.S. Treasury for collection or tax refund offset and may assess administrative costs.
226.176	226.43(j)	No substantive change.
226.177	226.44	The proposed rule clarifies the procedures for filing administrative appeals of decisions the Superintendent and Regional Director issue.
226.178 (new)	N/A	The proposed rule sets forth the procedures for filing administrative appeals of orders that ONRR issues.
226.179 (new)	N/A	The proposed rule specifies the conditions for suspension of compliance with an ONRR order during an administrative appeal.
226.180 (new)	N/A	The proposed rule sets forth the requirements for posting an appeal bond or other surety on an appellant's behalf for administrative appeals of ONRR orders.
226.181 (new)	N/A	The proposed rule specifies when an obligation to comply with an ONRR order is suspended due to judicial review.
226.182 (new)	N/A	The proposed rule specifies when ONRR will collect bonds and other surety instruments posted for administrative appeals.
226.183 (new)	N/A	The proposed rule specifies that the ONRR bond-approving officer's determination of the required surety amount is not subject to appeal.
226.184 (new)	N/A	The proposed rule sets forth the standards for ONRR-specified surety instruments.
226.185 (new)	N/A	The proposed rule explains how ONRR will determine the bond or surety instrument amount.
Appendix A	N/A	Table of Atmospheric Pressures to be used with §§ 226.123(a)(7) and (c)(10), 226.124(c), 226.126(a)(3), and 226.127(b).

VI. Procedural Matters

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

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) at the Office of Management and Budget (OMB) will review all significant rules. OIRA determined that this proposed rule is not significant.

Executive Order 13563 reaffirms the principles of Executive Order 12866, while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The Executive Order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 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. We developed this proposed rule in a manner consistent with these requirements.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601, *et seq.*) (RFA) requires Federal agencies to prepare a regulatory flexibility analysis for rules subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act (5 U.S.C. 500, *et seq.*) to determine whether a regulation would have a significant economic impact on a substantial number of small entities. The BIA does not believe the proposed rule would have a significant economic impact on a substantial number of small entities. Accordingly, a regulatory flexibility analysis is not required by the RFA. Although such analysis is not required, BIA performed an initial regulatory flexibility analysis pursuant to section 603 of the RFA as part of its Regulatory Impact Analysis (RIA). The IFRA, included as Appendix B to the RIA, analyzes impacts on small entities that may be affected by the proposed rule and is available upon request (see **ADDRESSES**). The IFRA for the proposed rule uses the best available information to identify potential impacts on small entities.

Small entities include small businesses, small governmental jurisdictions, and small organizations, as defined by section 601 of the RFA. A small entity is one that is independently owned and operated and is not dominant in its field of operation. The small entities most likely to be impacted by the proposed rule are small businesses in the mining sector; impacts to small governmental jurisdictions and small organizations are not anticipated. The Small Business Administration (SBA) defines small businesses in the crude petroleum and natural gas extraction industry as those with 1,250 employees or less. For subsector mining support activities, the SBA defines small businesses as drilling contractors with 1,000 employees or less and service companies with less than $41.5 million per year in revenues. Under these size standards, most oil and gas lessees and supporting entities within the Osage Mineral Estate would be classified as small businesses. Accordingly, the proposed rule would likely impact a substantial number of small entities within the Osage Mineral Estate.

Using the best available data for the past three years of production (2018–2020), there were an average of 223 lessees actively and exclusively producing oil from the Osage Mineral Estate, 5 lessees actively and exclusively producing gas from the Osage Mineral Estate, and 59 lessees actively producing both oil and gas from the Osage Mineral Estate, for a combined average of 286 lessees actively producing oil and gas. The volume of production varies substantially across lessees, with a substantial number of smaller lessees producing marginal volumes of oil and gas and several larger lessees producing the majority of annual production from the Osage Mineral Estate. For example, two lessees produced over 250,000 barrels of oil annually between 2018 and 2020, comprising 41 percent of all oil production from the Osage Mineral Estate during that period. In contrast, approximately 100 lessees during the same period produced less than 1,000 barrels of oil annually. The allocation of production for gas is similarly skewed.

To estimate the economic impacts on small entities, the IFRA estimates costs of the proposed rule for ''average'' lessees (286 active lessees) by assuming that lessees produce an average volume of oil and gas, that costs are shared equally across lessees, and that small entities would bear all costs of the proposed rule. The estimated costs of the proposed rule (including compliance costs, reporting and recordkeeping costs, and other payments) are $18,000 to $26,000 per year for ''average'' lessees, which could represent between 15 to 65 percent of annual profits depending on the lessee. As the IFRA assumes that costs are shared equally across lessees, however, the estimated per entity costs are higher than would be expected for lessees with small production volumes and lower than would be expected for lessees with large production volumes. For example, a lessee producing marginal oil volumes will have lower impacts from a change in the valuation of oil for royalty purposes than a lessee producing the ''average'' volume of oil.

The BIA does not believe the proposed rule would conflict with, duplicate, or overlap any relevant Federal rules in a way that would unnecessarily add cumulative regulatory burdens on small entities without any gain in regulatory benefits. BIA invites public comments identifying any Federal rules that may conflict with, duplicate, or overlap the proposed rule.

C. Small Business Regulatory Enforcement Fairness Act

This proposed rule is not a major rule under the Small Business Regulatory Enforcement Fairness Act, 5 U.S.C. 804(2). This proposed rule would not have an annual effect on the economy of $100 million or more; would not cause a major increase in the costs or prices for consumers, individual industries, Federal, State, local government agencies, or geographic regions; and would not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

D. Unfunded Mandates Reform Act

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

E. Takings (Executive Order 12630)

This proposed rule would not constitute a taking of private property or otherwise have takings implications under Executive Order 12630. The proposed rule would revise certain operational and administrative requirements for existing lessees. All such operations are subject to lease terms and conditions and a current regulation expressly requiring compliance with amendments to the regulations except that the term of the lease, acreage, rental rate, and royalty rate may not be changed absent agreement by both parties to the lease. The proposed rule conforms to those requirements. A takings implication assessment is not required.

F. Federalism (Executive Order 13132)

Under the criteria in Executive Order 13132, this proposed rule would not have a substantial direct effect on the States, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. A federalism impact statement is not required.

G. Civil Justice Reform (Executive Order 12988)

This proposed rule complies with the requirements of Executive Order 12988. Specifically, this proposed rule was reviewed to eliminate errors and ambiguity and written to minimize litigation. In addition, this proposed rule was written in clear language and contains clear legal standards.

H. Consultation With Indian Tribal Governments (Executive Order 13175)

The BIA evaluated this proposed rule under the criteria set forth in Executive Order 13175 and in accordance with Departmental policy to identify possible effects on federally recognized Indian Tribes and Indian trust assets. This proposed rule applies to oil and gas leasing and development activities within the Osage Mineral Estate in Osage County, Oklahoma. As the Osage Mineral Estate is held in trust by the United States for the benefit of the Osage Nation, this proposed rule has the potential to affect the Osage Nation.

On September 22, 2016, the BIA sent letters to the Osage Nation and Osage Minerals Council inviting their participation in government-to-government consultation to discuss potential revision of the regulations in this part. Both the Osage Nation and Osage Minerals Council expressed an interest in such consultation. On October 25, 2016, the BIA held a consultation with the Osage Nation, Osage Minerals Council, and their legal counsel in Pawhuska, Oklahoma and the parties agreed that revision of the regulations was appropriate. As part of the rulemaking effort, the BIA proposed that the process include an opportunity for the Osage Nation and Osage Minerals Council to provide input on proposed revisions to the regulations prior to the BIA preparing the proposed rule for publication in the **Federal Register**. The parties agreed that the BIA would prepare a discussion draft revising the regulations, provide it to the Osage Nation and Osage Minerals Council for review and comment, and hold a second government-to-government consultation to discuss Tribal representatives' feedback. Thereafter, the BIA would begin preparation of the proposed rule.

On August 18, 2020, the BIA provided the Osage Nation and Osage Minerals Council with the discussion draft revising the regulations in 25 CFR part 226. The BIA proposed that the parties conduct the second government-to-government consultation to receive the Tribe's feedback on the discussion draft in November 2020. On October 7, 2020, the Osage Minerals Council requested that the review period for the discussion draft be extended to February 1, 2021. The BIA agreed to the extension. On December 16, 2020, the Osage Minerals Council requested an additional government-to-government consultation prior to providing feedback on the discussion draft. The BIA agreed to conduct an additional consultation, but the Osage Nation and Osage Minerals Council did not respond to communications attempting to schedule the consultation.

On February 11, 2021, the Director of the Bureau of Indian Affairs, exercising the delegated authority of the Assistant Secretary—Indian Affairs, sent a letter to the Osage Nation and Osage Minerals Council advising of the deadline for scheduling the additional consultation requested and providing feedback on the discussion draft. On February 25, 2021, the Osage Minerals Council responded and declined the BIA's invitation to provide written feedback on the discussion draft and participate in government-to-government consultations relating thereto. The BIA advised the Osage Nation and Osage Minerals Council that they would still have the opportunity to provide feedback following publication of the proposed rule in the **Federal Register**.

On February 22, 2022, the Osage Minerals Council sent a letter to the Assistant Secretary—Indian Affairs requesting that the BIA not publish a proposed rule based on the discussion draft the Council received in 2020 and, instead, work with the Council to prepare a new set of regulations. The Assistant Secretary—Indian Affairs spoke with the Chairman of the Osage Minerals Council by phone and explained that the proposed rule had already been prepared and the BIA was in the process of completing the procedural requirements for publication. The Assistant Secretary—Indian Affairs advised that the BIA remained open to consulting with the Osage Nation and Osage Minerals Council following publication of the proposed rule in the **Federal Register** and noted that written feedback can also be provided as part of the public comment process.

I. Paperwork Reduction Act

All information collections require approval under the Paperwork Reduction Act of 1995 (PRA), 44 U.S.C. 3501, *et seq.* We may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget (OMB) Control Number. There are BIA and ONRR information collection requirements in this proposed rule. The BIA is proposing to renew its information collection with revisions (OMB Control No. 1076–0180) and ONRR is proposing to renew two information collections with revisions (OMB Control Nos. 1012–0004 and 1012–0006).

1. OMB Control Number 1076–0180 (BIA)

The OMB has reviewed and approved information collections for the existing regulations in 25 CFR part 226, which are assigned OMB Control No. 1076–0180. The BIA is proposing to renew information collection 1076–0180 with revisions. The following BIA revisions to reporting and recordkeeping requirements in the proposed rule require OMB's approval:

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
226.6(b)	Lessees must provide the name and address for a designated point of contact upon whom the Superintendent can serve official correspondence regarding the lease and operations thereon.	Osage Form A—Lease Contact of Record.
226.9(a)	Lessees may submit a draft environmental assessment (EA) for proposed drilling operations and any other proposed ground-disturbing activities occurring outside the existing well pad. This requirement is the same as the requirement in existing § 226.2(c).	None.
226.9(b)	Lessees must submit a Cultural Resources Survey for proposed drilling operations and any other proposed ground-disturbing activities occurring outside the existing well pad if the location of the operations or activities is not covered by a prior survey. This requirement is the same as the requirement in existing § 226.2(c).	None.
226.12(b)	The Osage Minerals Council (OMC) may request that the Superintendent negotiate a non-competitive lease with a prospective lessee on its behalf by submitting a Resolution authorizing the Superintendent to undertake such action. This requirement is the same as the requirement in existing § 226.2(f).	None.
226.13(a)	The OMC may request that the Superintendent advertise a competitive lease sale by submitting a Resolution that specifies the proposed location, date, and time of the lease sale as well as the minimum acceptable bid. This requirement is the same as the requirement in existing § 226.2(f).	None.
226.14(a)	An individual who wants to nominate a tract for a competitive lease sale must submit a nomination letter that includes their name and address as well as the legal description of the tract they are nominating. This requirement is the same as the requirement in existing § 226.2(a).	None.
226.17(a)(2) through (4)	The successful bidder at a competitive lease sale must submit an executed lease form, evidence of authority to execute papers form, and certificate of good standing from the Oklahoma Secretary of State. This requirement is the same as the requirement in existing § 226.2(b).	Osage Form B—Evidence of Authority to Execute Papers. Osage Form C—Oil and/or Gas Mining Lease.
226.19(a)(2) through (4)	A prospective lessee who negotiates a non-competitive lease with the OMC must submit an executed lease form, evidence of authority to execute papers form, and certificate of good standing from the Oklahoma Secretary of State. This requirement is the same as the requirement in existing § 226.2(f).	Osage Form B—Evidence of Authority to Execute Papers. Osage Form C—Oil and/or Gas Mining Lease.
226.21(b)	Lessees may submit a lease amendment form evidencing an agreement between the lessee and OMC to extend the primary term of the lease. This requirement is the same as the requirement in existing § 226.9(b).	Osage Form D—Lease Amendment.
226.24(b)	The lessee or OMC may submit a proposed cooperative agreement whereby the parties agree to unitize or merge one or more leases of the Osage Mineral Estate to promote development. This requirement is the same as the requirement in existing § 226.15(a).	None.
226.24(c)	The lessee or OMC may submit an agreement whereby the parties agree to modify, amend, or terminate an approved cooperative agreement. This requirement is the same as the requirement in existing § 226.15(a).	None.
226.26(c)	A lessee (assignor) may submit a lease assignment form transferring record title in an approved lease to another existing or prospective lessee (assignee). This requirement is the same as the requirement in existing § 226.15(b).	Osage Form E—Assignment of Record Title Interest.
226.33(a)	Lessees must submit a request to surrender all or part of an approved lease. This requirement is the same as the requirement in existing § 226.3.	None.
226.34(d)	Lessees must submit a copy of any agreement with a surface owner where the parties agree that the lessee can remove permanent improvements from the lease following termination. This requirement is the same as the requirement in existing § 226.29(a).	None.

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
226.36	The OMC must submit a Resolution approving a royalty rate for oil that is below the regulatory minimum of 12½ percent. This requirement is the same as the requirement in existing § 226.11(a).	None.
226.39	The OMC must submit a Resolution approving a royalty rate for gas that is below the regulatory minimum of 12½ percent. This requirement is the same as the requirement in existing § 226.11(b).	None.
226.42(b)	The OMC must submit a Resolution providing notice of its intention to take oil and/or gas royalty in kind. This requirement is the same as the requirement in existing § 226.11(a), except that the new provision allows the OMC to take both oil and gas royalty in kind, instead of allowing the OMC to only take oil royalty in kind.	None.
226.44(a)	Lessees must submit contracts or division orders with purchasers of oil and gas. This requirement is the same as the requirement in existing § 226.14, except that the Superintendent's approval of contracts and division orders is no longer required.	None.
226.46(b)	Lessees must make, retain, and preserve royalty, rental, and payment records for six years from the date upon which the relevant transaction was recorded or such longer period as the Superintendent or ONRR may require. This requirement is the same as the requirement in existing § 226.30, except that it reduces the burden by providing a specific timeframe for record retention and clarifies that both the Superintendent ONRR may request the subject records.	None.
226.51(c), 226.52(a) and (b)	Lessees must file an individual well bond for each well the lessee proposes to drill, reenter, recomplete, or accept responsibility for through assignment; a countywide bond covering all leases of the Osage Mineral Estate (10,240 acres maximum); or a nationwide bond covering all leases within the United States to which the lessee is a party. This requirement is the same as the requirement in existing § 226.6(a).	Osage Form F—Oil and Gas Lease Bond.
226.56(a) and (c)	Lessees and permittees must file an Oil and Gas Exploration Bond Form for geophysical exploration operations. An existing lessee with a countywide or nationwide Oil and Gas Lease Bond may file a bond rider covering geophysical exploration operations in lieu of filing an Oil and Gas Exploration Bond. There is no form for bond riders because they are prepared by the surety.	Osage Form G—Oil and Gas Geophysical Exploration Bond.
226.65(b)	Lessees must submit a request to expand an approved drilling site beyond the acreage set forth in the approved EA. This requirement is the same as the requirement in existing § 226.19(b).	None.
226.66(a)	Lessees must submit an application for a permit to drill or reenter a well. This requirement is the same as the requirement in existing § 226.16(b), but the burden on respondents is reduced because Osage Form 139 is now a fillable form that can be completed and submitted electronically.	Osage Form 139—Application for Permit to Drill or Workover Wells.
226.66(c)	Lessees must notify the Superintendent of planned drilling and reentry operations five days prior to the commencement thereof. Notice may be provided by phone or email. This requirement is the same as the requirement in existing § 226.16(c), except that the new provision specifies that the timeframe for providing notice is five days as opposed to "a reasonable time in advance.".	None.
226.66(d)	Lessees must submit a request to drill a well within 300 feet of the lease boundary or locate a well or tank within 200 feet of roads or highways maintained for public use, water sources, and residences, granaries, and barns. This requirement is the same as the requirement in existing § 226.33.	None.
226.67(b)	Lessees must submit a request to drill a well that deviates significantly from the vertical and report the drilling of any well that deviates significantly from the vertical without prior approval.	None.
226.69(a)	Lessees must submit an application for a permit to workover a well. This requirement is the same the requirement in existing § 226.16(b), but the burden hours are reduced because Osage Form 139 is now a fillable form that can be completed and submitted electronically.	Osage Form 139—Application for a Permit to Drill or Workover Wells.
226.69(c)	Lessees must notify the Superintendent of planned workover operations five days prior to the commencement thereof. Notice may be provided by phone or email. This requirement is the same as the requirement in existing § 226.16(c), except that the new provision specifies that the timeframe for providing notice is five days as opposed to "a reasonable time in advance.".	None.
226.70(a)	Lessees must submit the results of H_2S concentration tests upon request and submit radius of exposure calculations for any well or production facility with an H_2S concentration of 100 ppm or more.	None.
226.70(b)(1) and (2)	Lessees must report any release of a potentially hazardous volume of H_2S as soon as practicable, but not later than 24 hours following identification of the release. Notice must be provided by phone. A lessee must submit a Public Protection Plan for the potential release of a hazardous volume of H_2S if: 1. The 100 ppm radius of exposure is greater than 50 feet and includes any part of a residence, school, church, park, place of business, or other area the general public can reasonably be expected to frequent; 2. The 500 ppm radius of exposure is greater than 50 feet and includes any part of a federal, state, county, or municipal road or highway that is owned and maintained for public use; or	None.

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
	3. The 100 ppm radius of exposure if greater than or equal to 3,000 feet. The regulations specify the information that Public Protection Plans must include.	
226.70(d)	Lessees must maintain a record of all tests of H_2S monitoring systems and make the records available to the Superintendent upon request.	None.
226.72	Lessees must submit a request to temporarily abandon a well for more than 30 calendar days. This requirement is the same as the requirement in existing § 226.28.	None.
226.73(d)	Lessees must submit an application for a permit to plug a well. This requirement is the same the requirement in existing § 226.28(a), (c), but the burden hours are reduced because Osage Form 139 is now a fillable form that can be completed and submitted electronically.	Osage Form 139—Application for a Permit to Drill, Workover, or Plug Wells.
226.73(f)	Lessees must notify the Superintendent of planned plugging operations five days prior to the commencement thereof. Notice may be provided by phone or email. This requirement is the same as the requirement in existing § 226.16(c), except that the new provision specifies that the timeframe for providing notice is five days as opposed to ''a reasonable time in advance.''.	None.
226.73(h)	Lessees must submit any agreement with a surface owner whereby the parties agree that lessee will condition a well that is being plugged for the surface owner's use as a water supply well. This requirement is the same as the requirement in existing § 226.29(d).	None.
226.74(a)	Lessees must make all books and records relating to lease operations available to the Superintendent upon request. This requirement is the same as the requirement in existing § 226.30.	None.
226.74(c) through (f)	Lessees must submit a report upon completion of all approved drilling, workover, and plugging operations, together with copies of the results for all samples, tests, and surveys conducted on the well; copies of the electrical, mechanical, and radioactive logs or other surveys of the wellbore; core analysis; and for plugging operations, cementing tickets. This requirement is the same as the requirement in existing § 226.32(a), (b) and (c). Lessees must submit a report upon completion of hydraulic fracturing operations together with a report of the fracking fluids used. The regulations specify the information that such reports of fracking fluids must include. Lessees or owners of the fracking fluid information may withhold proprietary information that is exempt from public disclosure by submitting a signed withholding statement.	Osage Form 208—Well Completion or Recompletion Report. Osage Form 209—Report of Workover or Plugging Operations. Osage Form 210—Withholding of Proprietary Hydraulic Fracturing Information.
226.74(h)	Lessees must maintain well records and reports for six years from the date they were generated unless the Superintendent requires a longer retention period due to an audit or investigation. This requirement is the same as the requirement in existing § 226.32(c), except that the new provision specifies the timeframe for retention.	None.
226.76	Lessees must submit the results of tests and surveys performed to establish the effectiveness of measures taken to protect fresh water and mineral bearing formations upon request. This requirement is the same as the requirement in existing § 226.35.	None.
226.77(c)	Lessees must submit a request to construct, utilize, enlarge, or relocate a pit. This requirement is the same as the requirement in existing § 226.22(d).	None.
226.77(d)	Lessees must file a copy of any agreement whereby the lessee and surface owner reach an alternative agreement regarding the emptying and leveling of pits. This requirement is the same as the requirement in existing § 226.22(b).	None.
226.77(f)	Lessees must submit a request for the land-application of waste	None.
226.79(a)	A lessee or individual wishing to conduct oil and gas geophysical exploration activities within the Osage Mineral Estate must submit an Application for an Oil and Gas Geophysical Exploration Permit. This requirement is the same as the requirement in existing § 226.16(a), except that the Proposed Rule provides a form for such applications.	Osage Form 339—Application for Oil and Gas Geophysical Exploration Permit.
226.80	A lessee or permittee must notify the Superintendent of planned oil and gas geophysical operations five days prior to the commencement thereof. Notice may be provided by phone or email.	None.
226.81	A lessee or permittee must submit a Completion Report for Oil and Gas Geophysical Exploration Operations providing a subsequent report of the exploration operations performed.	Osage Form 408—Completion Report for Oil and Gas Geophysical Exploration Operations.
226.82(d)	A person claiming an interest in leased lands for the purpose of the settlement of surface damages must notify the Superintendent of that interest. This requirement is the same as the requirement in existing § 226.20(d).	None.
226.83(f)	A lessee or permittee must file a report of each settlement agreement whereby the lessee or permittee and an Indian landowner agree to the amount of surface damages to be paid. This requirement is the same as the requirement in existing § 226.21(g).	None.
226.84(e)	Lessees must report the emergency pumping of oil into a pit. Emergency reports must be submitted by phone.	None.

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
226.86(a) through (e)	Lessees must submit a site facility diagram for all permanent facilities. The regulations specify the information that site facility diagrams must include and the timeframe for submitting site facility diagrams, which varies depending on the date the relevant facilities became operational. Lessees have an ongoing obligation to update and amend site facility diagrams if facilities are modified to ensure that the diagrams accurately represent facilities. Sample site facility diagrams are available at *https://www.bia.gov/regional-offices/eastern-oklahoma/osage-agency*.	None.
226.88(a) through (c)	Lessees, purchasers, transporters, and other persons involved in producing, transporting, purchasing, selling, or measuring oil and gas must retain all records for a minimum of six years from the date upon which the relevant transaction was recorded unless the Superintendent or ONRR requires retention for a longer period. Such records must be made available to the Superintendent or ONRR upon request. The regulations specify the information that production records must include.	None.
226.92(b)	A lessee may request the use of alternative protective measures to prevent drainage.	None.
226.97(a) and (b)	Persons engaged in transporting oil by motor vehicle or pipeline must maintain documentation showing the amount, origin, and intended first purchaser of the oil.	None.
226.98	Lessees, purchasers, or transporters who drain water from a production storage tank must document such draining operations. The regulations specify the information that documentation of water draining operations must include.	None.
226.99(a)	Lessees must document the removal of oil from storage, temporary use of the oil for operations, and return of the oil to storage during hot-oil, clean-up, or completion operations. The regulations specify the information that documentation for temporary removal of oil from storage must include.	None.
226.100	Lessees must maintain a record of the seals used on valves and meter components. The regulations specify the information that seal records must include.	None.
226.101(a)	Lessees must submit a request for off-lease measurement of production. The regulations specify the information that requests for off-lease measurement of production must include.	None.
226.102(a) and (c)	Lessees must report spills, theft, mishandling of production, blowouts, fires, and accidents that occur on the lease by phone or email immediately upon discovery, but not later than one calendar day following discovery. Lessees must also submit a written report of the incident together with a proposed contingency or remediation plan. The initial report of spills, theft, mishandling of production, blowouts, fires, and accidents is provided by phone. This requirement is the same as the requirement in existing § 226.41.	Osage Form H—Spill and Remediation Report.
226.107(f)	Lessees measuring oil by tank gauging must submit tank tables within 45 days after calibrating a tank or recalculation of the tables. This requirement is the same as the requirement in existing § 226.38, except that the new provision specifies the timeframe for submitting tank tables.	None.
226.108(a)	Lessee must submit a request to use automatic tank gauging for oil measurement. The regulations specify the information that requests to use automatic tank gauging must include. This requirement is the same as the requirement in existing § 226.38.	None.
226.108(b)(5)(ii)(B)	Lessees must submit a detailed log of field verifications of automatic tank gauges upon request. This requirement is the same as the requirement in existing § 226.38.	None.
226.109(e)	Lessees must provide notice of any LACT system failures or equipment malfunctions that may have resulted in measurement error within 15 calendar days of discovering such failure or malfunction.	None.
226.112(c), (e), (f), and (g)	Lessees must submit Coriolis meter specifications upon request. Lessees must maintain the following information on-site at the FMP: • Make, model, and size of each sensor; • Make, model, range, and calibrated span of the pressure and temperature transducers used to determine gross standard volume; and • A log of all meter factors, zero verifications, and zero adjustments. Lessees must retain QTRs, configuration logs, event logs, and alarm logs for six years from the date they were generated or such longer period as the Superintendent may require.	None.
226.113(b)	Lessees must have a certificate of calibration for the meter prover (*e.g.,* a device that verifies the accuracy of the meter) on-site and available for review.	None.
226.113(j)	Lessees must submit a report of meter proving and volume adjustments within 14 days after any LACT system or CMS malfunction, including excessive meter-factor deviation.	None.
226.114(d)	Lessees must submit run tickets on or before the last calendar day of the month following the production month. The regulations specify the information that run tickets for tank gauging, LACT, and CMS must include. This requirement is the same as the requirement in existing § 226.16(b), except that the new provision specifies the information run tickets must contain. The information required is consistent with what is currently submitted and prevailing industry standards.	None.
226.115	Lessees must submit a request to use any method of oil measurement other than tank gauging, LACT system, or CMS.	None.

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
226.116(c)	Lessees must submit a request to sell or dispose of slop oil and, following the approved sale or disposal of slop oil, must submit a report identifying the volume of slop oil sold or disposed of, the method used to computer that volume, and the gross revenue from the sale. This provision codifies lessees' existing practices for the sale or disposal of slop oil. Accordingly, it does not impose a new burden on lessees with respect to such sales.	None.
226.121(e)	Lessees must document orifice plate inspections and include that documentation as part of the verification report submitted in accordance with §§ 226.123 (for mechanical recorders) or 226.126 (for EGM systems). The regulations specify the information that documentation of orifice plate inspections must include.	None.
226.121(i)	Lessees must document meter tube inspections and must make such documentation available upon request. The regulations specify the information that documentation of meter tube inspections must include.	None.
226.121(j)	Lessees must notify the Superintendent at least 72 hours in advance of performing basic or detailed meter tube inspections under § 226.121(d), (g), and (h) or submit a monthly or quarterly schedule or inspections. Notice may be provided by phone or email. This provision codifies lessees' existing practice of providing notice of meter tube inspections but specifies that 72 hours' advance notice be provided. The provision introduces the option for lessees to submit inspection schedules to provide additional flexibility for notice requirements.	None.
226.122(g)	Lessees must maintain certain data at FMPs for mechanical recorders. The regulations specify the information that mechanical recorder data maintained at FMPs must include.	None.
226.123(d)	Lessees must retain documentation of mechanical recorder verifications and make such documentation available to the Superintendent upon request. The regulations specify the information that documentation of mechanical recorder verifications must include.	None.
226.123(e)	Lessees must notify the Superintendent at least 72 hours in advance of performing mechanical recorder verifications following installation or repair or performing routine verifications. Notice may be provided by phone or email, or lessees may submit a monthly or quarterly schedule of verifications.	None.
226.123(g)	Purchasers or purchasers' representatives must retain documentation of test equipment certifications on-site. The regulations specify the information that documentation of certification of test equipment include. This collection does not impose a burden on respondents pursuant to 5 CFR 1320.3(h)).	None.
226.124(a)	Lessees must retain an unedited integration statement and make such statement available to the Superintendent upon request. The regulations specify the information that unedited integration statements must include. Lessees already obtain integration statements containing the above information consistent with industry standards. This provision codifies lessees' existing practices. The requirement to retain such statements is the same as the requirement in existing § 226.30.	None.
226.125(e)	Lessees must maintain certain data at FMPs for EGM systems. The regulations specify the information that data for EGM systems must include.	None.
226.126(e)	Lessees must retain documentation of each verification of EGM systems and make such documentation available to the Superintendent upon request. The regulations specify the information that documentation of EGM system verifications must include.	None.
226.126(f)	Lessees must notify the Superintendent at least 72 hours before conducting routine EGM system verifications and verifications following installation or repairs. Notice may be provided by phone or email, or lessees may submit a monthly or quarterly verification schedule. This provision codifies lessees' existing practice of providing notice EGM verifications but specifies that 72 hours' advance notice be provided.	None.
226.126(h)	Purchasers or purchasers' representatives must maintain documentation of test equipment certifications on-site. The regulations specify the information that documentation of test equipment certifications must include. This collection does not impose a burden on respondents pursuant to 5 CFR 1320.3(h)).	None.
226.128(a)	Lessees must retain QTRs for EGM systems and make them available to the Superintendent upon request. The regulations specify the information that QTRs for EGM systems must include.	None.
226.128(b)	Lessees must retain the original, unaltered, unprocessed, and unedited configuration log for the EGM system and make it available upon request. The regulations specify the information that configuration logs must include.	None.
226.128(c)	Lessees must retain the original, unaltered, unprocessed, and unedited event log for the EGM system and make it available upon request. The regulations require the configuration log to contain the information identified in API 21.1, subsection 5.5 and have sufficient capacity to be retrieved and stored at intervals that will maintain a continuous record of events for either the required six-year retention period or the life of the FMP, whichever is shorter.	None.
226.128(d)	Lessees must retain an alarm log and make it available upon request. The regulations require alarm logs to comply with the requirements set forth in API 21.1, Subsection 5.6.	None.

Section(s)	Proposed revision(s) to OMB 1076–0180	OMB 1076–0180 form(s)
226.131(b)	Lessees must notify the Superintendent at least 72 hours before obtaining a spot sample. Notice may be provided by phone or email, or lessees may submit a monthly or quarterly sampling schedule. This provision codifies lessees' existing practice of providing notice of spot sampling but specifies that 72 hours' advance notice be provided. The provision introduces the option for lessees to submit spot sample schedules to provide additional flexibility for notice requirements.	None.
226.131(c)	Lessees must maintain documentation of the cleaning of sample cylinders and make such documentation available upon request.	None.
226.132(a)(2)	Lessees must maintain documentation demonstrating that the cylinder was evacuated and pre-charged before sampling for spot sampling using the Helium "pop" method and make such documentation available upon request.	None.
226.132(a)(3)	Lessees must maintain documentation of the seal material and type of lubricant used for the floating piston cylinder method of spot sampling and make such documentation upon request.	None.
226.136(e)	Lessees must retain documentation of the gas chromatograph verifications and make the documentation available upon request. The regulations specify the information that documentation of gas chromatograph verifications must include.	None.
226.138(a), (e)	Lessees must submit all gas analysis reports within 14 calendar days after the due date for the sample as specified in § 226.133. The regulations specify the information that gas analysis reports must include.	None.
226.141(c)(2)	Lessees must document all edits made to reported heating value or volume data before the report is submitted to ONRR, including verifiable justifications for the edits made, and such documentation must be made available upon request.	None.
226.142(d)	Lessees must submit a request to stop furnishing gas to Tribally owned buildings or enterprises or members of the Osage Nation residing in Osage County. This requirement is the same as the requirement in existing § 226.27(b)(3).	None.
226.146(b)	Lessees must submit a request for certain royalty-free uses of production on the lease or unit. The regulations require the Superintendent's approval of: • Use of oil or gas the lessee removes from the pipeline at a location downstream of the FMP; • Use of gas that has been removed from the lease or unit for treatment or processing because the particular physical characteristics of the gas require it to be treated or processed prior to use, where the gas is returned to, and used on, the same lease or unit from which it is produced; and • Any other uses of produced oil and gas for operations and production purposes that are not set forth in § 226.145. The regulations specify the information that requests for royalty-free use of production on the lease or unit must include.	None.
226.148(c)	Lessees must submit a request for certain royalty-free uses of production off the lease or unit. The regulations require the Superintendent's approval of royalty-free treatment of oil or gas used in operations conducted off the lease or unit if the: • Use is among those listed in §§ 226.145(a) or 226.146(a); • Equipment or facility in which the operation is conducted is located off the lease or unit for engineering, economic, resource protection, or physical accessibility reasons; and • Operations are conducted upstream of the FMP. The regulations specify the information that requests for royalty use of production off the lease or unit must include.	None.
226.149(d)	Lessees must notify the Superintendent in writing if oil or gas is removed downstream of the FMP for royalty-free use pursuant to §§ 226.145 through 226.148 and obtain an approved FMP to measure the production removed for use.	None.
226.152(a)	Lessees must submit a request to vent or flare gas. The regulations require the Superintendent's approval to vent or flare gas to ensure that the natural gas disposed of through venting or flaring is properly measured and, where applicable, proper royalties paid. This provision codifies the Superintendent's existing notice to lessees requiring prior approval for all venting and flaring. Accordingly, this provision does not impose a new burden on lessees.	None.
226.158	Lessees must submit a self-certification following the correction of any lease violations for which a notice of non-compliance is received. This provision codifies the Superintendent's existing requirement that self-certification forms be submitted upon completion of the correction of lease violations. Accordingly, this provision does not impose a new burden on lessees.	Osage Form I—Self-Certification for Correction of Lease Violations.

Title of Collection: Mining of the Osage Mineral Estate for Oil and Gas.

OMB Control Number: 1076–0180.

Abstract: Under the 1906 Act, the BIA is required to administer oil and gas leasing and development of the Osage Mineral Estate. The BIA needs to perform the IC activities set forth in the regulations at 25 CFR part 226 to perform its responsibilities under the statute.

Form Number: Osage Form A (Lease Contact of Record); Osage Form B (Evidence of Authority to Execute Papers); Osage Form C (Oil and Gas Mining Lease); Osage Form D (Lease Amendment); Osage Form E (Assignment of Record Title Interest); Osage Form F (Oil and Gas Lease Bond); Osage Form G (Oil and Gas Geophysical Exploration Bond); Osage Form H (Spill and Remediation Report); Osage Form I (Self-Certification for Correction of Lease Violations); Osage Form 139 (Application for Permit to Drill or Workover Wells); Osage Form 208 (Well Completion or Reentry Report); Osage Form 209 (Report of Workover or Plugging Operations); Osage Form 210 (Withholding of Proprietary Hydraulic Fracturing Information); Osage Form 339 (Application for Permit to Conduct Oil and Gas Geophysical Exploration Operations); Osage Form 408 (Oil and Gas Geophysical Exploration Completion Report).

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Individual Indians, businesses, and Tribal authorities.

Total Estimated Number of Annual Respondents: 4,974.

Total Estimated Number of Annual Responses: 59,196.

Estimated Completion Time per Response: Varies from six minutes to 40 hours.

Total Estimated Number of Annual Burden Hours: 22,564.

Respondent's Obligation: Required to obtain a benefit.

Frequency of Collection: Varies from monthly to yearly.

Total Estimated Annual Non-Hour Burden Cost: $0.

2. OMB Control Number 1012–0004 (ONRR)

The OMB has reviewed and approved information collections for ONRR's royalty and production reporting operations throughout the rest of Indian country, which are assigned OMB Control No. 1012–0004. ONRR is proposing to renew information collection 1012–0004 with revisions to provide for such collections within the Osage Mineral Estate. The following ONRR royalty and production reporting and recordkeeping requirements in the proposed rule require OMB's approval:

Section(s)	Proposed revision(s) to OMB 1012–0004	OMB 1012–0004 Form(s)
226.43(c) and (d)	Lessees must make royalty payments to ONRR by EFT (preferred) or the other forms of payment identified in § 226.8. Non-EFT royalty payments submitted via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO 80225–0627. Royalty reports submitted manually via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Entrance N–1, Room 332, 6th Avenue and Kipling Street, Denver, CO 80225.	None.
226.45	Lessees must submit certified monthly royalty reports to ONRR by 4 p.m. mountain time on or before the last calendar day of the month that follows the month during which the oil and gas is produced and sold. Royalty reports must be submitted electronically via ONRR's eCommerce Reporting website, https://onrrreporting.onrr.gov, unless the lessee meets the qualifications for manual reporting. Royalty reports submitted manually via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO 80225–0627. Royalty reports submitted manually via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Entrance N–1, Room 332, 6th Avenue and Kipling Street, Denver, CO 80225.	ONRR 2014—Report of Sales and Royalty Remittance.
226.46	Lessees must make, retain, and preserve records demonstrating that rental, royalty, and other payments relating to oil and gas leases comply with the terms and conditions of the lease, the regulations in 25 CFR part 226, and applicable orders and notices. Lessees must preserve records for a minimum of six years from the date upon which the relevant transaction was recorded unless the Superintendent or ONRR provides notice that records must be maintained for a longer period due to investigation or audit. Lessees must make records available to the Superintendent ONRR for inspection upon request. Covered under burden for §§ 226.32(c) and (d) and 226.45.	None.
226.85	Lessees must submit certified monthly productions reports to ONRR by 4 p.m. mountain time on or before the 15th day of the second month following the production month. Production reports must be submitted electronically via ONRR's eCommerce Reporting website, https://onrrreporting.onrr.gov, unless the lessee meets the qualifications for manual reporting. Production reports submitted manually via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO, 80225–0627. Production reports submitted manually via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Entrance N–1, Room 332, 6th Avenue and Kipling Street, Denver, CO 80225.	ONRR 4054—Oil and Gas Operations Report (OGOR).
226.88	Lessees, purchasers, transporters, and other persons involved in producing, transporting, purchasing, selling, or measuring oil and gas through the point of royalty measurement or point of first sale, whichever is later, must retain all records, including source records, relevant to determining the quality, quantity, disposition, and verification of production attributable to the subject lease. The regulations specify the information that production records must include. Production records must be preserved for a minimum of six years from the date upon which the relevant transaction was recorded unless the Superintendent or ONRR provides notice that records must be maintained for a longer period due to investigation or audit. Lessees must make records available to the Superintendent ONRR for inspection upon request. Covered under burden for § 226.85.	None.

Title of Collection: Royalty and Production Reporting.

OMB Control Number: 1012–0004.

Revisions: Under the 1906 Act, the BIA is required to administer oil and gas leasing and development of the Osage Mineral Estate. The proposed rule would allow BIA to transfer the royalty and production reporting and compliance functions for the Osage Mineral Estate to ONRR. ONRR would perform the specified IC activities in 25 CFR part 226 to carry out the BIA's responsibilities and ensure that lessees pay proper royalties and revenues on oil and gas produced from the Osage Mineral Estate. The requirement to timely and accurately report royalties and production is mandatory.

Form Number: ONRR–2014, ONRR–4054.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Businesses.

Total Estimated Number of Annual Respondents: 3,490 oil, gas, and geothermal reporters.

Total Estimated Number of Annual Responses: 12,827,063 lines of data.

Estimated Completion Time per Response: Varies between 1 and 7 minutes per line, depending on the activity. The average completion time is 1.72 minutes per line. The average completion time is calculated by first multiplying the estimated annual burden hours (369,379) by 60 to obtain the total annual burden minutes. Then the total annual burden minutes (22,162,740) is divided by the estimated annual number of lines submitted (12,827,063).

Total Estimated Number of Annual Burden Hours: 369,379.

Respondent's Obligation: Mandatory.

Frequency of Collection: Monthly.

Total Estimated Annual Non-Hour Burden Cost: ONRR identified no ''non-hour cost'' burden associated with this information collection.

3. OMB Control Number 1012–0006 (ONRR)

The OMB has reviewed and approved information collections for ONRR's suspensions pending appeal and bonding throughout the rest of Indian country, which are assigned OMB Control No. 1012–0006. ONRR is proposing to renew information collection 1012–0006 with revisions to provide for such collections within the Osage Mineral Estate. The following ONRR suspensions pending appeal and bonding requirements in the proposed rule require OMB's approval:

Section(s)	Proposed revision(s) to OMB 1012–0006	OMB 1012–0006 Form(s)
226.179(b)(2)	A party who appeals an order regarding the payment and reporting of royalties, or other payments due, may suspend compliance with such order by submitting an ONRR-specified surety instrument within 60 days after receiving the Order or Notice of Order.	ONRR 4435—Administrative Appeal Bond. ONRR 4436—Letter of Credit. ONRR 4437—Assignment of Certificate of Deposit.
226.180(a)	Any other person, including a designee, payor, or affiliate, may post a bond or other surety instrument on behalf of an appellant. If such person is assuming an appellant's responsibility, they must notify ONRR in writing of such assumption. Covered under burden for § 226.179(b)(2).	None.
226.182(b)(2)	ONRR will suspend an obligation to comply with an order if the amount under appeal is $1,000 or more if the appellant submits an ONRR-specified surety instrument within the required timeframe. Covered under burden for § 226.179(b)(2).	None.
226.185(c)	An appellant whose appeal is not decided within one year from the filing date must increase the surety amount to cover additional estimated interest for another one-year period and continue such increases annually. Covered under burden for § 226.179(b)(2).	None.

Title of Collection: Suspensions Pending Appeal and Bonding.

OMB Control Number: 1012–0006.

Revision: Under the 1906 Act, the BIA is required to administer oil and gas leasing and development of the Osage Mineral Estate. The proposed rule would allow BIA to transfer the royalty and production reporting and compliance functions for the Osage Mineral Estate to ONRR. ONRR would perform the specified IC activities in 25 CFR part 226 to carry out enforcement and compliance actions for the Osage Mineral Estate.

Form Number: ONRR–4435, ONRR–4436, and ONRR–4437.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Businesses.

Total Estimated Number of Annual Respondents: 107.

Total Estimated Number of Annual Responses: 107.

Estimated Completion Time per Response: The time per response is 120 mins. The average completion time is calculated by first multiplying the estimated annual burden hours (214 burden hours) by 60 to obtain the total annual burden minutes. Then the total annual burden minutes (12,840) is divided by the estimated annual responses (107).

Total Estimated Number of Annual Burden Hours: 214.

Respondent's Obligation: Mandatory.

Frequency of Collection: Annually and on occasion.

Total Estimated Annual Non-Hour Burden Cost: There are no additional recordkeeping costs associated with this information collection. However, ONRR estimates 5 appellants per year will pay a $50 fee to obtain credit data from a business information or credit reporting service, which is a total non-hour cost burden of $250 per year (5 appellants per year × $50 = $250).

J. National Environmental Policy Act

This proposed rule does not constitute a major Federal action significantly affecting the quality of the human environment under the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321, *et seq.* Therefore, this proposed rule is categorically excluded from further review under 43 CFR 46.210(i) because these are regulations ''whose environmental effects are too broad, speculative, or conjectural to lend themselves to meaningful analysis and will later be subject to the NEPA review process either collectively or case by case.'' No extraordinary circumstances exist that require greater NEPA review.

K. Effects on the Energy Supply (Executive Order 13211)

This proposed rule is not a significant energy action under the definition in Executive Order 13211. A statement of Energy Effects is not required.

L. Clarity of This Regulation (Executive Orders 12866, 12988, and 13563)

We are required by Executive Orders 12866, 12988, and 13563 and by the

Presidential Memorandum of June 1, 1988, to write all rules in plain language. This means that each rule must:

(a) Be logically organized;

(b) Use the active voice to address readers directly;

(c) Use clear language rather than jargon;

(d) Be divided into short sections and sentences; and

(e) Use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments using one of the methods listed in the **ADDRESSES** section. To better help the BIA revise the rule, your comments should identify the numbers of the sections or paragraphs that you find unclear and specify which sections or sentences are too long, the sections where you believe lists or tables would be useful.

List of Subjects in 25 CFR Part 226

Administrative practice and procedure, Environmental protection, Incorporation by reference, Indians-lands, Mineral royalties, Oil and gas exploration, Oil and gas measurement, Penalties, Reporting and recordkeeping requirements.

For the reasons stated in the preamble, the Bureau of Indian Affairs proposes to revise 25 CFR part 226 as follows:

PART 226—MINING OF THE OSAGE MINERAL ESTATE FOR OIL AND GAS

Subpart A—General

Sec.

Authority: Sec. 3, Pub. L. 59–321, 34 Stat. 543; Secs. 1–2, Pub. L. 66–360, 41 Stat. 1249; Secs. 1–2, Pub. L. 70–919, 45 Stat. 1478; Sec. 3, Pub. L. 75–711, 52 Stat. 1034; Pub. L. 81–548, 65 Stat. 215; Pub. L. 88–632, 78 Stat. 1008; Secs. 2, 4, Pub. L. 95–496, 92 Stat. 1660.

Subpart A—General

§ 226.0 Incorporation by reference (IBR).

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than those specified in this section, the Bureau of Indian Affairs (BIA) must publish a document in the **Federal Register**, and the material must be available to the public. All approved incorporation by reference (IBR) material is available for inspection at the BIA and at the National Archives and Records Administration (NARA). To inspect the material at BIA, contact: the BIA Osage Agency, 513 Grandview Avenue, Pawhuska, OK 74056; phone 918–287–5700. For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations.html* or email *fr.inspection@nara.gov.* The material may be obtained from the following sources:

(a) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20005; phone: 202–682–8000; website: *https://www.api.org*.

(1) API Manual of Petroleum Measurement Standards (MPMS), Chapter 2—Tank Calibration, Section 2A—Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method; First Edition, February 1995; Reaffirmed August 2017 (''API 2.2A''); IBR approved for § 226.107(f).

(2) API MPMS Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method; First Edition, March 1989; Reaffirmed, April 2019; Addendum 1, October 2019 (''API 2.2B''); IBR approved for § 226.107(f).

(3) API MPMS Chapter 2—Tank Calibration, Section 2C—Calibration of Upright Cylindrical Tanks Using the Optical-Triangulation Method; First Edition, January 2002; Reaffirmed April 2019 (''API 2.2C''); IBR approved for § 226.107(f).

(4) API MPMS Chapter 3—Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products; Third Edition, August 2013; Reaffirmed December 2018 (''API 3.1A''); IBR approved for § 226.108(b).

(5) API MPMS Chapter 3—Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging; Third Edition, April 2018 (''API 3.1B''); IBR approved for § 226.108(b).

(6) API MPMS Chapter 3—Tank Gauging, Section 6—Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems; First Edition, February 2001; Errata September 2005; Reaffirmed January 2017 (''API 3.6''); IBR approved for § 226.108(b).

(7) API MPMS Chapter 4—Proving Systems, Section 1—Introduction; Third Edition, February 2005; Reaffirmed June 2014 (''API 4.1''); IBR approved for § 226.113(c).

(8) API MPMS Chapter 4—Proving Systems, Section 2—Displacement Provers; Third Edition, September 2003; Reaffirmed March 2011, Addendum February 2015 (''API 4.2''); IBR approved for § 226.113(b) and (c).

(9) API MPMS Chapter 4—Proving Systems, Section 5—Master-Meter Provers; Fourth Edition, June 2016, (''API 4.5''); IBR approved for § 226.113(b).

(10) API MPMS Chapter 4—Proving Systems, Section 6—Pulse Interpolation; Second Edition, May 1999; Errata April 2007; Reaffirmed October 2013 (''API 4.6''); IBR approved for § 226.113(c).

(11) API MPMS Chapter 4—Proving Systems, Section 8—Operation of Proving Systems; Second Edition, September 2013 (''API 4.8''); IBR approved for § 226.113(b).

(12) API MPMS Chapter 4—Proving Systems, Section 9—Methods of Calibration for Displacement and Volumetric Tank Provers, Part 2—Determination of the Volume of Displacement and Tank Provers by the Waterdraw Method of Calibration; First Edition, December 2005; Reaffirmed July 2015 (''API 4.9.2''); IBR approved for § 226.113(b).

(13) API MPMS Chapter 5—Metering, Section 6—Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, October 2002; Reaffirmed November 2013 (''API 5.6''); IBR approved for §§ 226.111(d); 226.113(i) and (j).

(14) API MPMS Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems; Second Edition, May 1991; Reaffirmed May 2012 (''API 6.1''); IBR approved for § 226.110(a) and (b).

(15) API MPMS Chapter 7—Temperature Determination, Section 1—Liquid-in-glass Thermometers, Second Edition, August 2017 (''API 7.1''); IBR approved for § 226.108(b).

(16) API MPMS Chapter 7—Temperature Determination, Section 2—Portable Electronic Thermometers; Third Edition, May 2018 (''API 7.2''); IBR approved for § 226.108(b).

(17) API MPMS Chapter 7—Temperature Determination, Section 4—Dynamic Temperature Measurement, Second Edition, January 2018 (''API 7.4''); IBR approved for § 226.110(b).

(18) API MPMS Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products; Fourth Edition, October 2013 (''API 8.1''); IBR approved for §§ 226.108(b); 226.113(i).

(19) API MPMS Chapter 8—Sampling, Section 2—Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; Fourth Edition, November 2016 (''API 8.2''); IBR approved for §§ 226.110(b); 226.113(i).

(20) API MPMS Chapter 8—Sampling, Section 3—Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products; First Edition, October 1995; Reaffirmed, March 2015 (''API 8.3''); IBR approved for §§ 226.110(b); 226.113(i).

(21) API MPMS Chapter 9—Density Determination, Section 1—Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method; Third Edition, December 2012; Reaffirmed May 2017 (''API 9.1''); IBR approved for §§ 226.108(b); 226.110(b).

(22) API MPMS Chapter 9—Density Determination, Section 2—Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer; Third Edition, December 2012; Reaffirmed May 2017 (''API 9.2''); IBR approved for §§ 226.108(b); 226.110(b).

(23) API MPMS Chapter 9—Density Determination, Section 3—Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method; Third Edition, December 2012; Reaffirmed May 2017 (''API 9.3''); IBR approved for §§ 226.108(b); 226.110(b).

(24) API MPMS Chapter 10—Sediment and Water, Section 4—Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure); Fourth Edition, October 2013; Errata March 2015 (''API 10.4''); IBR approved for §§ 226.108(b); 226.110(b).

(25) API MPMS Chapter 11—Physical Properties Data, Section 1—Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products and Lubricating Oils; May 2004, Addendum 1 September 2007, Addendum 2 May 2019; Reaffirmed August 2012 (''API 11.1''); IBR approved for §§ 226.109(g); 226.110(b); 226.111(e); 226.114(a).

(26) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets; Third Edition, June 2003; Reaffirmed February 2016 (''API 12.2.2''); IBR approved for § 226.110(b).

(27) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3—Proving Report; First Edition, October 1998; Reaffirmed May 2014 (''API 12.2.3''); IBR approved for § 226.113(c) and (j).

(28) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4—Calculation of Base Prover Volumes by the Waterdraw

Method; First Edition, December 1997; Reaffirmed September 2014 (''API 12.2.4''); IBR approved for § 226.113(b).

(29) API MPMS Chapter 13—Statistical Aspects of Measuring and Sampling, Section 3—Measurement Uncertainty; Second Edition, December 2017 (''API 13.3''); IBR approved for § 226.106(a).

(30) API Manual of Petroleum Measurement Standards (MPMS) Chapter 14—Natural Gas Fluids Measurement, Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer; Seventh Edition, May 2016; Addendum August 2017; Errata August 2017 (''API 14.1''); IBR approved for §§ 226.130(b) and (c); 226.131(c); 226.132(b).

(31) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 1—General Equations and Uncertainty Guidelines; Fourth Edition, September 2012; Errata July 2013; Reaffirmed September 2017 (''API 14.3.1''); IBR approved for §§ 226.106(a); 226.120(a).

(32) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 2—Specification and Installation Requirements; Fifth Edition, March 2016; Errata 1, March 2017; Errata 2, January 2019 (''API 14.3.2''); IBR approved for § 226.121(b) through (f), (h), (i), and (l).

(33) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 3—Natural Gas Applications; Fourth Edition, November 2013 (''API 14.3.3''); IBR approved for §§ 226.124(b); 226.127(a).

(34) API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 5—Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; Reaffirmed November 2020 (''API 14.5''); IBR approved for §§ 226.138(c); 226.140(a).

(35) API MPMS Chapter 18—Custody Transfer, Section 1—Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck; Third Edition, May 2018 (''API 18.1''); IBR approved for § 226.108(b).

(36) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement; Second Edition, February 2013 (''API 21.1''); IBR approved for §§ 226.125(a) and (g); 226.126(a), (c), and (d); 226.127(c); 226.128(a) through (d).

(37) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters; First Edition, June 1998; Reaffirmed October 2016 (''API 21.2''); IBR approved for §§ 226.110(b); 226.111(e); 226.112(g).

(38) API Recommended Practice (RP) 12R1, Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service; Fifth Edition, August 1997; Reaffirmed April 2008; Addendum 1, December 2017 (''API RP 12R1''); IBR approved for § 226.107(b).

(39) API RP 2556, Correction Gauge Tables for Incrustation; Second Edition, August 1993; Reaffirmed November 2013 (''API RP 2556''); IBR approved for § 226.107(f).

(b) American Gas Association (AGA), 400 North Capitol Street NW, Suite 450, Washington, DC 20001; phone: 202–824–7000; website: *https://www.aga.org.*

(1) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Second Edition, September 1985 (''AGA Report No. 3''); IBR approved for § 226.124(b).

(2) AGA Transmission Measurement Committee Report No. 8, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases; Second Edition, November 1992 (''AGA Report No. 8''); IBR approved for §§ 226.127(a); 226.138(d).

(c) Gas Processors Association (GPA), 6526 E. 60th Street, Tulsa, OK 74145; phone 918–493–3872; website: *https://www.gpamidstream.org.*

(1) GPA Midstream Standard 2166–17, Obtaining Natural Gas Samples for Analysis by Gas Chromatography; Reaffirmed 2017 (''GPA 2166–17''); IBR approved for §§ 226.131(c) and (d); 226.132(a); 226.135(a).

(2) GPA Midstream Standard 2261–20, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography; Revised 2020 (''GPA 2261–20''); IBR approved for § 226.136(a) and (c).

(3) GPA Midstream Standard 2198–16, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends; Revised 2016 (''GPA 2198–16''); IBR approved for § 226.136(c).

§ 226.1 Definitions.

(a) As used in this part, the term:

Alarm log means a log for recording any system alarm, user-defined alarm, or error conditions (such as out-of-range temperature or pressure) that occur. This includes a description of each alarm condition and the times the condition occurred and cleared.

Appropriate valve means those valves that provide access to production before it is measured for sales and that are subject to the sealing requirements set forth in this part.

Area ratio means the smallest unrestricted area at the primary device divided by the cross-sectional area of the meter tube. For example, the area ratio (A_r) of an orifice plate is the area of the orifice bore (A_d) divided by the area of the meter tube (A_D). For an orifice plate with a bore diameter (d) of 1.000 inches in a meter tube with an inside diameter (D) of 2.000 inches, the area ratio is 0.25 and is calculated as follows:

$$A_d = \frac{\pi d^2}{4} = \frac{\pi \cdot 1.000^2}{4} = 0.7854 in^2 \qquad A_D = \frac{\pi D^2}{4} = \frac{\pi \cdot 2.000^2}{4} = 3.1416 in^2$$

$$A_r = \frac{A_d}{A_D} = \frac{0.7854 in^2}{3.1416 in^2} = 0.25$$

As-found means the reading of a mechanical or electronic transducer when compared to a certified test device, prior to making any adjustments to the transducer.

As-left means the reading of a mechanical or electronic transducer when compared to a certified test device after adjusting the transducer, but prior to returning the transducer to service.

Audit means a review of production reporting, royalty reporting, or payment activities of lessees, designees, or other persons or entities who report production or pay royalties, rents, bonuses, or other revenues on leases or properties where a lease, or portion of a lease, is committed to a cooperative agreement.

Automatic ignition system means an automatic ignitor and, where needed to ensure continuous combustion, a continuous pilot flame.

Averaging period means the previous 12 months or life of the meter, whichever is shorter. For an FMP that measures production from a newly drilled well, the averaging period excludes production from the well that occurred during or prior to the first full month of production.

Barrel (bbl) means 42 standard United States gallons.

Beta (or diameter) ratio means the reference inside diameter (measured inside diameter corrected to a reference temperature of 68 °F) of the orifice bore divided by the reference inside diameter of the meter tube. This is also referred to as a diameter ratio.

Bias means a shift in the mean value of a set of measurements away from the true value of what is being measured.

Business day means any day Monday through Friday, excluding weekends and Federal holidays.

Bypass means any piping or equipment used at an FMP to go around or otherwise avoid a meter or other measurement device, or any component thereof, to allow oil or gas to flow without accountability. Equipment that allows the changing of the orifice plate of a gas meter without bleeding the pressure off the gas meter run (*e.g.,* senior fitting) is not a bypass.

Capture means the physical containment of natural gas for transportation to market or productive use of natural gas and includes injection and royalty-free on-site uses pursuant to the regulations in this part.

Calendar day means all days in a month, including weekends and Federal holidays.

Composite meter factor means a meter factor corrected from normal operating pressure to base pressure. The composite meter factor is determined by proving operations where the pressure is considered constant during the measurement period between provings. This definition applies to liquid meter provings only.

Configuration log means a record that contains all selected flow parameters used in the generation of a quantity transaction record.

Cooperative agreement means a binding legal agreement between two or more parties for the development or operation of a designated area as a single unit without regard to separate ownership of the leased lands included in the agreement. Such cooperative agreements include, but are not limited to, unit agreements and communitization agreements.

Coriolis measurement system (CMS) means a metering system using a Coriolis meter in conjunction with a tertiary device, pressure transducer, and temperature transducer to derive and report gross standard oil volume. A CMS system provides real-time, on-line measurement of oil.

Deleterious substance means any chemical, saltwater, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or other injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil and gas.

Director means the Director of ONRR, the Director's authorized representative acting under delegated authority, or such other person as the Director may delegate to fulfill responsibilities and exercise authorities under this part.

Discharge coefficient means an empirically derived correction factor that is applied to the theoretical differential flow equation to calculate a flow rate that is within stated uncertainty limits.

Drainage means the migration of hydrocarbons, inert gases, or associated resources caused by production from other wells.

Effectively sealed means sealed in such a manner that the sealed component cannot be accessed, moved, or altered without breaking the seal.

Element range means the difference between the minimum and maximum value that the element of a mechanical recorder (*e.g.,* differential-pressure bellows, static pressure element, temperature element) is designed to measure.

Ephemeral stream or water source means a stream or water source that only flows in direct response to precipitation and whose channel is always above the water table.

Escape rate means the maximum volume of gas determined to be available for escape (Q), calculated as follows:

(1) For production facilities, the maximum daily rate of gas produced through that facility or the best estimate thereof;

(2) For oil wells, the producing gas/oil ratio multiplied by the maximum daily production rate or the best estimate thereof; and

(3) For gas wells, the current daily absolute open flow rate against atmospheric pressure.

Event log means an electronic record of all exceptions and changes to the flow parameters contained within the configuration log that have an impact on a quantity transaction record.

Facility measurement point (FMP) means a point where oil or gas produced from a lease is measured and such measurement affects calculation of the volume or quality of production on which royalty is owed. Each individual meter installation (including its primary, secondary, and tertiary devices) and tank battery is a separate FMP.

Free water means the measured volume of water that is present in a container and that is not in suspension in the contained liquid at observed temperature.

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

Gas-to-oil ratio (GOR) means the ratio of gas to oil in the production stream expressed in standard cubic feet of gas per barrel of oil.

Gas plant products means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas. This does not include residue gas.

Gas well means a well that produces natural gas that is not associated with oil at the time of well completion or for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced by at least 15,000 standard cubic feet for each barrel of oil produced at the time of well completion.

Geophysical exploration means activity relating to the search for evidence of oil and gas which requires physical presence upon surface lands and may result in damage to the lands or resources located thereon. This includes, but is not limited to, geophysical operations, construction of roads and trails, cross-country transit of vehicles, and drilling operations to place explosive charges, where approved. This does not include drilling for oil and gas.

Gross proceeds means the total monies and other consideration accruing to a lessee for the disposition of the oil, gas, or other marketable products produced.

Gross standard volume means a volume of oil corrected to base pressure and temperature and includes meter factor, as applicable.

Heating value means the gross heat energy released by the complete combustion of one standard cubic foot of gas at 14.73 psia and 60 °F.

High-volume FMP means any gas FMP that measures more than 200 Mcf/day, but less than 1,000 Mcf/day, over the averaging period. This definition only applies to gas FMPs; it does not apply to oil FMPs on an equivalent-gas basis.

Indicated volume means the uncorrected volume indicated by the meter in a LACT system or the Coriolis meter in a CMS. For a positive displacement meter, the indicated volume is represented by the non-resettable totalizer on the meter head. For Coriolis meters, the indicated volume is the uncorrected (without the meter factor) mass of liquid divided by the density.

Innage gauge means the level of a liquid in a tank, measured from the datum plate or tank bottom to the surface of the liquid.

Intermittent stream or water source means a stream or water source flowing only at certain times of the year when it receives water from springs or other surface sources.

Knowingly or willfully means an act, or failure to act, that is committed with actual knowledge, deliberate ignorance, or reckless disregard of the facts surrounding the event or violation; it requires no proof of specific intent to defraud. The knowing or willful nature of conduct may be established by plain indifference or reckless disregard of the terms and conditions of the lease or permit or applicable laws, regulations, orders, or notices. A consistent pattern of performance, or failure to perform, may be sufficient to establish the knowing or willful nature of the conduct. Conduct that is regarded as knowing or willful is not accidental, nor is it mitigated by the belief that the conduct is reasonable or legal.

Lease means any contract approved by the United States under the Act of June 28, 1906, Public Law 59–321, 34 Stat. 539, as amended, that authorizes exploration for, or the extraction and removal of, oil and gas from the Osage Mineral Estate.

Lease automatic custody transfer (LACT) system means a system of components designed for the unattended custody transfer of oil produced from a lease or unit to the transporting carrier. The system must determine the net standard volume and quality and provide for safe and tamper-proof operations.

Legal description means the geographical description of a location utilizing the quarter-section, section, township, and range.

Lessee means any person holding record title to, or owning operating rights in, an oil and/or gas lease issued under the regulations in this part and any authorized representative thereof, including any designee who reports production or submits royalty payments on behalf of the lessee.

Liquids unloading means the removal of an accumulation of liquid hydrocarbons or water from the wellbore of a completed gas well.

Lost oil or gas means produced oil or gas that escapes containment, whether such loss is intentional or unintentional, or that is flared before being removed from the lease or unit and cannot be recovered.

Low-volume FMP means any gas FMP that measures more than 35 Mcf/day, but less than or equal to 200 Mcf/day, over the averaging period. This definition only applies to gas FMPs; it does not apply to oil FMPs on a gas-equivalent basis.

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

Maximum ultimate economic recovery means the recovery of oil and gas that a prudent lessee could be expected to make from the field or reservoir given existing knowledge and other pertinent facts and utilizing common industry practices for primary, secondary, or tertiary recovery operations.

Meter factor means a ratio obtained by dividing the measured volume of liquid that passed through a prover or master meter during the proving by the measured volume of liquid that passed through the line meter during the proving, corrected to base pressure and temperature.

Mole percent means the number of molecules of a particular type that are present in a gas mixture divided by the total number of molecules in the gas mixture, expressed as a percentage.

Monthly Index Zone Price means the index-based value per MMBtu for gas production from a lease in an index zone. The Monthly Index Zone Price is calculated by averaging the highest reported prices for all index-pricing points in the relevant index zone for each ONRR-approved publication, summing those averages, dividing by the number of ONRR-approved publications, and reducing the number calculated by 10 percent, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu.

Natural gas liquids (NGLs) means gas plant products consisting of ethane, propane, butane, or heavier liquid hydrocarbons.

Net standard volume means the gross standard volume corrected for quantities of non-merchantable substances such as sediment and water.

NYMEX Calendar Month Average Price means the average of the New York Mercantile Exchange (NYMEX) daily settlement prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows: (1) Sum the prices published for each day during the calendar month of production, excluding weekends and Federal holidays, for oil to be delivered in the nearest month of delivery for which NYMEX futures prices are published corresponding to each such day; and (2) Divide the sum by the number of days on which those prices are published, excluding weekends and Federal holidays.

Oil well means a well for which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced at the time of completion.

Operating right (working interest) means a percentage of ownership in a lease granting the owner the right to enter upon the leased lands to conduct exploratory, drilling, or related operations, including the production of oil and gas, in accordance with the terms and conditions of the lease.

Orphan well means an oil, gas, disposal, injection, or service well that is no longer in use whether dry, inoperable, or incapable of production; that the current lessee did not assume through assignment; that has not been drilled, re-entered, operated, or affected by the current lessee; and for which there is no legally or financially responsible party with sufficient resources to conduct proper plugging, abandonment, and surface restoration operations.

Osage Minerals Council means the independent agency within the Osage Nation created by Article XV, section 4, of the Constitution of the Osage Nation (2006) with administrative authority to consider and approve leases of the Osage Mineral Estate and propose other forms of development thereof, and its successors in interest.

Osage Mineral Estate means the subsurface mineral estate underlying Osage County, Oklahoma that is held in trust by the United States for the benefit of the Osage Nation in accordance with the Act of June 28, 1906, Public Law 59–321, section 3, 34 Stat. 539, as amended.

Osage Nation means the federally recognized Indian Tribe referred to by Article I of the Constitution of the Osage Nation (2006) and its predecessors and successors in interest.

Perennial stream or water source means a stream or water source that flows continuously.

Permittee means any person, other than a lessee, who applies for and receives a geophysical exploration permit.

Person means any individual, corporation, partnership, association, firm, consortium, joint venture, or other entity.

Primary term means the initial term of the lease during which the lease contract may be kept in force by either commencement of production in paying quantities or the payment of annual rental.

Production in paying quantities means production of oil or gas from a lease that is of sufficient value to exceed direct operating costs and the cost of annual rental or minimum royalty.

Production phase means that event during which oil is delivered directly to or through production equipment to the storage facilities and includes all operations at the facility other than those defined as being within the sales phase.

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

Quantity transaction record (QTR) means a report generated by a flow computer on a LACT, CMS, or other approved system that summarizes the daily and/or hourly volume calculated by the flow computer and the average or totals of the dynamic data that is used in the calculation of gross standard volume.

Record title means a lessee's interest in a lease which includes the obligation to pay rental and the right to assign or surrender the lease. Overriding royalty and operating rights are severable from record title interests.

Regional Director means the Regional Director for the Eastern Oklahoma Region, Bureau of Indian Affairs, or the Regional Director's authorized representative acting under delegated authority.

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

Sales phase means that event during which oil is removed from storage facilities at an FMP for sale.

Seal means a uniquely numbered device that completely secures either a valve or those components of a measuring system that affect the quality or quantity of the oil being measured.

Senior fitting means a type of orifice plate holder that allows the orifice plate to be removed, inspected, and replaced without isolating and depressurizing the meter tube.

Slop oil means oil that is of such quality that it is not acceptable to normal purchasers and is usually sold to oil reclaimers. Oil that can be made acceptable to normal purchasers through special treatment economically provided at existing or modified facilities or using portable equipment at, or upstream of, the FMP, is not slop oil.

Source record means any unedited, original record, document, or data that is used to determine the volume and quality of production, regardless of how it was created or stored or the format it is in (*i.e.,* paper or electronic). This includes, but is not limited to, raw and unprocessed data (*e.g.,* instantaneous and continuous information used by flow computers to calculate volumes); gas charts; run tickets; calibration, verification, prover and configuration reports; lessee field logs; volume statements; event logs; seal records; and gas analyses.

Statistically significant means a difference between two data sets that exceeds the threshold of significance. The threshold of significance is the maximum difference between two data sets (*a* and *b*) that can be attributed to uncertainty effects, and is calculated as follows:

$$T_s = \sqrt{U_a^2 + U_b^2}$$

Where:

T_s = Threshold of significance, in percent

U_a = Uncertainty (95 percent confidence) of data set a, in percent

U_b = Uncertainty (95 percent confidence) of data set b, in percent

Superintendent means the Superintendent of the Osage Agency, Bureau of Indian Affairs, the Superintendent's authorized representative acting under delegated authority, or such other person or official that may be delegated to fulfill responsibilities and exercise authorities under this part.

Surface owner means any person who owns a surface estate within Osage County, Oklahoma, regardless of whether the surface estate is held in fee, restricted fee, or trust status.

Total observed volume (TOV) means the total measured volume of all oil, sludge, S&W, and free water at the measured or observed temperature and pressure.

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, *http://www.cmegroup.com,* in which case the NYMEX definition will apply.

Upper calibrated limit means the maximum engineering value for which a transducer was calibrated by certified equipment, either in the factory or in the field.

US well number means a unique, permanent numeric identifier assigned to each oil and gas well drilled in the United States that includes the completion code.

Very-high-volume FMP means any gas FMP that measures more than 1,000 Mcf/day over the averaging period. This definition only applies to gas FMPs; it does not apply to oil FMPs on an equivalent-gas basis.

Very-low-volume FMP means any gas FMP that measures 35 Mcf/day or less over the averaging period. This definition only applies to gas FMPs; it does not apply to oil FMPs on an equivalent-gas basis.

Waste of oil or gas means any action or inaction by the lessee that is not sanctioned by the Superintendent as necessary for proper development and production, where compliance costs are not greater than the monetary value of the resources they are expected to conserve, and that results in:

(1) A reduction in the quality or quantity of oil or gas ultimately producible from a reservoir under prudent and proper operations; or

(2) Avoidable surface loss of oil or gas.

Waste oil means oil that the Superintendent determined is of such quality that it cannot be treated economically and put in a marketable condition with existing or modified lease facilities or portable equipment, cannot be sold to reclaimers, and has no economic value.

(b) As used in this part, the following acronyms apply:

API means American Petroleum Institute.

BIA means Bureau of Indian Affairs.

Btu means British thermal unit.

CPL means correction for the effect of pressure on a liquid.

CTL means correction for the effect of temperature on a liquid.

FCCP means a Failure to Correct Civil Penalty Notice.

ft msl means feet above mean sea level.

GPA means Gas Processors Association.

GPS means Global Positioning System.

IBIA means the Interior Board of Indian Appeals, Office of Hearings and Appeals.

IBLA means the Interior Board of Land Appeals, Office of Hearings and Appeals.

ILCP means an Immediate Liability Civil Penalty Notice.

IRS means Internal Revenue Service.

Mcf means 1,000 standard cubic feet.

MMBtu means million metric British thermal units.

MMcf means million cubic feet.

NIST means National Institute of Standards and Technology.

NONC means a Notice of Noncompliance.

NTL means Notice to Lessee(s).

ONRR means Office of Natural Resources Revenue.

psia means pounds per square inch—absolute.

psig means pounds per square inch—gauge.

S&W means sediment and water.

SWD means saltwater disposal.

§ 226.2 Authorities that govern oil and gas activities within the Osage Mineral Estate.

All oil and gas exploration and development activities conducted within the Osage Mineral Estate are subject to:

(a) The regulations in this part;

(b) Lease and permit terms and conditions;

(c) Orders, notices, and instructions the Superintendent issues;

(d) Orders, notices, and instructions ONRR issues; and

(e) All other applicable laws, regulations, and authorities.

§ 226.3 Authority and responsibility of the Superintendent of the Osage Agency.

The Superintendent of the Osage Agency has the authority and responsibility to administer leasing and development of the Osage Mineral Estate.

§ 226.4 Authority and responsibility of the Office of Natural Resources Revenue (ONRR).

The Office of Natural Resources Revenue (ONRR) has the authority and responsibility for administering the Osage Agency's royalty management program including, but not limited to, royalty and production accounting, reporting, verification, collection, enforcement, and appeals.

§ 226.5 Orders and notices.

(a) The Superintendent is authorized to issue orders and notices when necessary to implement, supplement, clarify, and enforce the regulations in this part. Orders and notices the Superintendent issues under this section are binding on the lessee and any other persons they apply to. The Superintendent may, in their discretion, grant an extension of the time to comply with an order or notice.

(b) ONRR is authorized to issue orders and notices when necessary to implement, supplement, clarify, and enforce the regulations in this part. Orders that ONRR issues under this section are binding on the lessee and any other persons they apply to.

§ 226.6 Service of official correspondence.

(a) The Superintendent and ONRR will serve all official correspondence by regular U.S. mail, certified mail—return receipt requested, private delivery service (*i.e.,* UPS or FedEx), or hand delivery.

(b) The Superintendent will serve official correspondence to the party identified on the most recently received Lease Contact of Record form. The lessee is responsible for notifying the Superintendent of any change in the designated point of contact's name, address, or phone number by submitting an updated form within two weeks of any such change.

(c) ONRR will serve official correspondence to the party identified on the most recently received Form ONRR–4444, Address/Addressee of Record, for the type of correspondence at issue. The reporter is responsible for notifying ONRR of any name or address changes within two weeks of any such change.

(d) If the lessee, reporting party, or payor fails to submit or update contact information in accordance with the requirements in this section:

(1) The Superintendent may use the name and address listed on the lease; and

(2) ONRR may use the individual or departmental name, address, or position title, contained in ONRR's database based on previous formal or informal communications or correspondence.

(e) The Superintendent and ONRR may also obtain contact information from public records and send official correspondence to:

(1) The registered agent;

(2) A corporate officer; or

(3) The addressee of record reflected in the files of any state Secretary, any Federal or state agency that keeps official records of business entities or corporations, or other appropriate public records for individuals, business entities, and corporations.

(f) The Superintendent and ONRR consider the date of service for official correspondence to be:

(1) Seven calendar days for regular U.S. mail;

(2) The date of receipt for certified mail—return receipt requested and private delivery service; and

(3) The date of delivery for hand delivery.

(g) If, the Superintendent or ONRR serves official correspondence using multiple methods and the dates of receipt differ, the date of the earliest receipt is the date of service.

(h) If, after a reasonable effort, the Superintendent or ONRR are unable to deliver official correspondence to the contact of record, the correspondence will be considered constructively served seven calendar days after the original mailing date. This includes, but is not limited to, situations where delivery does not occur because:

(1) The contact of record moved without filing a forwarding address, Lease Contact of Record form, or ONRR Form-4444;

(2) The forwarding order expired;

(3) Delivery was expressly refused; or

(4) The correspondence was unclaimed and the U.S. Postal Service, a private mailing service, or an individual who attempted to make delivery using a different method of service substantiates the delivery attempt.

§ 226.7 Forms.

Leases, assignments, applications, bonds, affidavits, reports, and other instruments must be on forms approved by the Superintendent or ONRR. Only the official version and current edition of such forms will be accepted.

§ 226.8 Acceptable forms of payment.

All sums due under a lease or the regulations in this part must be paid by electronic funds transfer (EFT), certified check, cashier's check, money order, or commercial or personal check drawn on a solvent bank, otherwise specified herein or notified by the Superintendent or ONRR in writing. Such sums constitute a prior lien on all equipment and unsold oil located on the lease or unit.

§ 226.9 Environmental reviews and cultural surveys.

Prior to approving leases and permit applications for operations requiring new or additional ground-disturbance, the Superintendent must:

(a) Ensure that environmental review has been conducted in accordance with the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321, *et seq.,* the regulations promulgated by the Council on Environmental Quality (CEQ), 40 CFR parts 1500 through 1508, and the Department's regulations implementing NEPA, 43 CFR part 46, and that an environmental record of review (*e.g.,* categorical exclusion checklist, determination of NEPA adequacy), environmental assessment, or environmental impact statement has been prepared, as appropriate.

(b) Ensure that all necessary archeological or cultural surveys are performed, and clearances obtained, in accordance with the National Historic Preservation Act (NHPA), 54 U.S.C. 300101, *et seq.,* the regulations promulgated by the Advisory Council on Historic Preservation, 36 CFR part 800 *et seq.,* and the Archaeological Resources Protection Act of 1979 (ARPA), 16 U.S.C. 470aa–470mm, as applicable.

§ 226.10 Information collection.

The collections of information in this part have been approved by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.* and assigned OMB Control Number 1076–0180 (BIA collections) and OMB Control Numbers 1012–0004 and 1012–0006 (ONRR collections). Response is required to obtain a benefit. A Federal agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a valid OMB Control Number.

§ 226.11 Public availability of information.

The BIA and ONRR will make all records and information submitted in accordance with the regulations in this part available to the public for inspection, without notification of the submitter, subject to the following exceptions:

(a) Trade secrets;

(b) Privileged or confidential commercial or financial information; and

(c) Information protected from disclosure by the Privacy Act (5 U.S.C. 552a).

Subpart B—Acquiring a Lease

Authorized Procedures

§ 226.12 Procedures the Osage Minerals Council may use to enter into a lease.

The Osage Minerals Council may utilize the following procedures to enter into a lease of the Osage Mineral Estate:

(a) Competitive bidding at an advertised lease sale; or

(b) Negotiation with prospective lessees. The Osage Minerals Council may negotiate directly or request that the Superintendent undertake negotiation on its behalf. Requests that the Superintendent negotiate leases must be submitted in writing together with a resolution authorizing such negotiation.

Competitive Leases

§ 226.13 Advertisement of a lease sale.

(a) The Osage Minerals Council may request that the Superintendent advertise a competitive lease sale. Such requests must be submitted to the Superintendent in writing at least 60 calendar days in advance of the date the Osage Minerals Council would like the Notice of Lease Sale published, together with a resolution authorizing the lease sale. The resolution must identify the:

(1) Location, date, and time of the lease sale; and

(2) Minimum acceptable bid.

(b) Upon receipt of the Osage Minerals Council's written request under paragraph (a) of this section, the Superintendent will publish a Lease Sale Bulletin advertising the lease sale and calling for nominations.

§ 226.14 Nominating lands for a lease sale.

(a) You must submit a nomination letter to the Superintendent to nominate lands for a lease sale. The nomination letter must:

(1) Include the name and address of the person making the nomination;

(2) Identify the legal description of the lands nominated; and

(3) Be legible and signed in ink.

(b) Nomination letters must be submitted to the Superintendent by mail or hand delivery prior to expiration of the nomination period identified in the Lease Sale Bulletin. Nomination letters that do not meet the requirements in paragraph (a) of this section will be rejected.

§ 226.15 Publication of a Notice of Lease Sale.

The Superintendent will publish a Notice of Lease Sale at least 30 calendar days prior to the date of the sale. The Notice of Lease Sale will offer leases for sale to the highest responsible bidder and identify the nominated lands; primary term of each lease offered; location, date, and time of the sale; and method for submitting bids.

§ 226.16 Bidding system.

(a) Leases will be offered for sale by competitive bonus bidding under the terms and conditions specified in the Notice of Lease Sale and in accordance with applicable laws and regulations.

(b) All bids are subject to the Osage Minerals Council's acceptance and the Superintendent's approval. The Superintendent reserves the right to reject any bid and may require any bidder to submit evidence of good faith and ability to comply with the requirements in the Notice of Lease Sale.

(c) A winning bid is the highest bid by a qualified bidder that is equal to, or exceeds, the minimum acceptable bid.

(d) Each successful bidder must deposit 25 percent of the bonus bid with the Superintendent by 4:30 p.m. central standard time on the day of the lease sale. Deposits must be paid by EFT, cashier's check, or money order.

§ 226.17 Award of leases.

(a) A successful bidder must deposit the following with the Superintendent within 20 calendar days of the lease sale:

(1) The balance of the bonus;

(2) An executed Oil and Gas Mining Lease form;

(3) An Evidence of Authority to Execute Papers form; and

(4) A certificate of good standing issued by the Oklahoma Secretary of State.

(b) The Superintendent may extend the time for submitting the executed lease, evidence of authority to execute papers, and certificate of good standing. No extension of time may be granted for depositing the balance of the bonus.

(c) The bonus, or any portion thereof, deposited with the Superintendent will be forfeited for the use and benefit of the Osage Nation if:

(1) A successful bidder fails to pay the bonus in full by the required deadline;

(2) A successful bidder fails to file the items in paragraphs (a)(2) through (4) of this section by the required deadline; or

(3) The Superintendent denies approval of the lease pursuant to paragraph (d) of this section, through no fault of the Osage Minerals Council or BIA.

(d) Competitive leases are subject to the Superintendent's approval. The Superintendent may deny the approval of a lease executed by a successful bidder upon satisfactory evidence of collusion, fraud, or other irregularity.

Non-Competitive Leases

§ 226.18 Submitting an offer to lease.

(a) You may submit non-competitive offers to lease the Osage Mineral Estate to the Osage Minerals Council. Such offers must include the:

(1) Name and address of the offeror;

(2) Legal description of the lands covered by the proposed lease;

(3) Bonus amount; and

(4) Such other information as may be required by the Osage Minerals Council.

(b) Upon receipt of a non-competitive offer to lease, the Osage Minerals Council may accept the offer, reject the offer, or enter negotiations with the offeror directly or through the Superintendent.

§ 226.19 Acceptance of an offer to lease.

(a) A successful offeror must deposit the following with the Superintendent within 20 calendar days of the Osage Minerals Council's acceptance of a non-competitive offer to lease:

(1) The full bonus;

(2) An executed Oil and Gas Mining Lease form;

(3) An Evidence of Authority to Execute Papers form; and

(4) A certificate of good standing issued by the Oklahoma Secretary of State.

(b) Non-competitive leases are subject to the Superintendent's approval.

Lease Terms

§ 226.20 Types of leases.

All leases of the Osage Mineral Estate issued after [effective date of final rule] will be combination oil and gas leases. Oil-only and gas-only leases issued prior to [effective date of final rule] will remain in full force and effect until such time as they terminate or are cancelled but cannot be assigned unless the assignee executes a new combination oil and gas lease covering the subject lands.

§ 226.21 Primary term of leases.

(a) Leases will be for a primary term established by the Osage Minerals Council, subject to the Superintendent's approval, and will continue so long thereafter as oil and/or gas is produced in paying quantities.

(b) The Superintendent may approve an amendment extending the primary term of a lease for up to two years if actual drilling operations commenced prior to expiration of the primary term, operations are being diligently pursued at the end of the primary term, and the parties jointly submit a Lease Amendment form evidencing their agreement. This includes any lease that is part of an approved cooperative agreement where actual drilling operations took place within the unit or area covered by the agreement. The following requirements must be met to qualify for an extension of the primary term:

(1) Actual drilling operations must have been conducted in a manner consistent with serious oil and gas exploration in that area based on existing knowledge of the geology or other pertinent facts and information.

(2) In drilling a new well on a lease, or for the benefit of a lease pursuant to the terms of an approved cooperative agreement, the lessee must take the well to a depth sufficient to penetrate at least one formation recognized as having potential to produce oil or gas.

(3) In the reentry of an existing well, the lessee must take the well to a depth sufficient to penetrate at least one new and deeper formation recognized as having the potential to produce oil or gas.

§ 226.22 Effect of changes in current regulations on existing leases.

Leases issued pursuant to this part are subject to the current regulations, all of which are made a part of such leases. No amendment or change in the regulations after the approval of any lease will operate to affect the primary term, acreage, royalty rate, or rental set forth therein unless the parties jointly submit a Lease Amendment form evidencing their agreement to the amended terms and the Superintendent approves the amendment.

§ 226.23 U.S. Government employees may not acquire leases.

U.S. Government employees are prohibited from acquiring leases of the Osage Mineral Estate or any interests therein.

Subpart C—Cooperative Agreements and Unitization

§ 226.24 Cooperative agreements.

(a) The Osage Minerals Council and lessees may unitize or merge two or more leases into a cooperative agreement to promote the development of any pool, field, or similar area, or any part thereof, subject to the Superintendent's approval.

(b) The Osage Minerals Council and lessees must submit requests for approval of cooperative agreements to the Superintendent at least 90 calendar days prior to the earliest expiration date of any of the leases proposed to be covered by the agreement.

(c) Any agreement by the parties in interest to supplement, modify, amend, or terminate a cooperative agreement as to all the lands covered, or any portion thereof, is subject to the Superintendent's approval. Upon approval of termination, the leases covered by the cooperative agreement will be restored to their original terms.

§ 226.25 Unit development plans.

The Superintendent may, with the consent of the Osage Minerals Council, require all leases issued under this part to join a unit development plan for the purpose of preventing waste and promoting development of the Osage Mineral Estate. Any such plan must adequately protect the rights of all parties in interest.

Subpart D—Transferring a Lease by Assignment

§ 226.26 Assignment of record title interest in a lease.

(a) A lease, or any divided or undivided interest in a lease, may be transferred by assignment subject to the Superintendent's approval. If an assignment will only cover a portion of a lease, the transfer requires both the Osage Minerals Council's consent and the Superintendent's approval. The assignment of a separate zone or deposit, or part of a legal subdivision, is prohibited.

(b) If a lease is divided by the assignment of an entire interest in any part, the assigned and retained portions of the lease are segregated and become separate and distinct leases.

(c) The assignor must submit the Assignment of Record Title Interest form to the Superintendent for approval within 30 calendar days of the date the last party executes the instrument.

§ 226.27 Qualifications of the assignee.

The assignee must be qualified to hold the lease, or interest therein, under the regulations in this part and must furnish a satisfactory bond.

§ 226.28 Effective date of transfer.

The effective date of the transfer is 12:01 a.m. central standard time on the first calendar day following the day the Superintendent approves the assignment.

§ 226.29 Effect of assignment on the assignor's liability under the lease.

(a) The assignor remains liable for the performance of all lease obligations, monetary and non-monetary, that accrue in connection with the lease prior to the effective date of the assignment specified in § 226.28.

(b) After the assignment is approved, the Superintendent and ONRR may require the assignor to bring the lease into compliance if the assignee fails to satisfy an obligation that accrued prior to the effective date of the assignment.

This does not include the obligation to plug and abandon wells the assignee assumed liability for pursuant to the assignment.

§ 226.30 Effect of assignment on the assignee's liability under the lease.

(a) The assignee must comply with the terms and conditions of the lease, any approved permits for wells located thereon, and the regulations in this part as they apply to the rights and obligations acquired.

(b) The assignee is liable for all obligations that accrue after the effective date of the assignment specified in § 226.28 including, but not limited to, properly plugging and abandoning all wells that the assignee drills, operates, or controls following the effective date of the transfer and remediating environmental problems or other lease violations, regardless of whether such problems were identified at the time of the assignment. For purposes of this section, an assignee is considered to ''control'' all unplugged wells located on the lease that are recorded in the Osage Agency's plat book or that a purchaser exercising reasonable diligence could or should have known of at the time of the assignment, except for orphan wells that neither the assignor nor assignee occasioned.

§ 226.31 Overriding royalty agreements.

(a) Agreements creating overriding royalties or payments out of production are not considered an interest in a lease as that term is used in § 226.26.

(b) Agreements creating overriding royalties or payments out of production are hereby authorized and do not require the Superintendent's approval, subject to the condition that nothing in any such agreement will be construed as modifying the lessee's obligations under the terms and conditions of the lease or the regulations in this part. All such obligations remain in full force and effect, the same as if free of any overriding royalties or payments out of production.

(c) The Superintendent will not consider the existence of agreements creating overriding royalties or payments out of production as justification for approving the abandonment of any well, regardless of whether they are actually paid.

(d) The Superintendent will suspend an agreement creating overriding royalties or payments out of production if it is determined that the working interest income of an active producing well is less than or equal to the operational cost of the well.

§ 226.32 Drilling contracts.

The lessee is authorized to enter into drilling contracts with a stipulation that nothing in such contracts may bind the Department or otherwise require the Superintendent's approval of subsequent assignments that may be contemplated by the contract.

Subpart E—Ending a Lease

§ 226.33 Surrender of all or any portion of a lease.

(a) A lessee may surrender all or any portion of a lease at any time by submitting a written request for surrender to the Superintendent. All parties holding record title interests in the lease must sign the request for surrender.

(b) The Superintendent may approve the surrender, or partial surrender, of a lease subject to the following conditions:

(1) All royalties, including minimum and compensatory royalties, rental, interest, late charges, assessments, civil penalties, and other amounts that may be due under the regulations in this part have been paid in full; and

(2) All wells located on the leased lands being surrendered that are no longer capable of producing in paying quantities have been properly plugged and abandoned and the well sites restored.

(c) The Superintendent must obtain the Osage Minerals Council's consent to approve the partial surrender of a lease if the acreage to be retained is less than 160 acres.

(d) The lessee and surety are not relieved of any obligations or liabilities under the lease or the regulations in this part until the Superintendent approves the request for surrender.

(e) If a lease has been recorded, the lessee must execute a release and record it in the proper office upon the Superintendent's approval of the request for surrender.

(f) Surrender or partial surrender of a lease does not entitle the lessee to a refund of advance rental or other sums paid under the lease or the regulations in this part.

§ 226.34 Termination of a lease by operation of law.

(a) If a lessee fails to timely pay advance annual rental in accordance with § 226.35, the lease terminates by operation of law as of the date rental was due.

(b) If a lessee fails to drill a well capable of producing oil or gas in paying quantities during the primary term in accordance with § 226.21, the lease terminates by operation of law as of the date the primary term expires.

(c) Any lease in the extended term upon which there are no wells capable of producing oil or gas in paying quantities terminates by operation of law as of the date production ceases unless the Superintendent approved a request to temporarily abandon the wells on the lease under § 226.72.

(d) When a lease terminates, permanent improvements remain part of the land and become the property of the surface owner unless the lessee and surface owner agree otherwise. The lessee must file a copy of any such agreement with the Superintendent within 15 calendar days of its execution.

(e) The lessee must remove all trash, debris, and personal property from the lease within 90 calendar days of termination. For purposes of this section, personal property includes, but is not limited to, tools, tanks, pumping and drilling equipment, derricks, engines, machinery, tubing, and casings. Upon expiration of the 90-day removal period, the ownership of all casings reverts to the Osage Nation and the ownership of all other personal property transfers to the surface owner.

(f) Nothing in this section relieves the lessee of the responsibility for removing permanent improvements and personal property from the leased lands if the Superintendent orders such removal.

Subpart F—Rental and Royalty

Rental Obligations

§ 226.35 Annual rental requirements.

(a) The annual rental for leases approved after [effective date of final rule] is $8 per acre or fraction thereof.

(b) The lessee must pay advance annual rental for each year of the primary term within 15 calendar days of the Superintendent's approval of the lease. If the lease is amended to extend the primary term, the lessee must pay advance annual rental for each additional year of the primary term within 15 calendar days of the Superintendent's approval of the extension.

(c) Rental must be paid for a full year and may not be prorated, refunded, or credited against production royalty.

(d) Rental payments must be mailed to the Superintendent addressed to: Osage Agency—BIA, Dept. C155, P.O. Box 105533, Atlanta, GA 30348–5533.

Royalty Obligations

§ 226.36 Royalty rate for oil.

The lessee must pay to the Superintendent as royalty no less than 16⅔ percent of the value of all oil produced and removed or sold from the lease. The Osage Minerals Council may, upon presentation of justifiable economic evidence by a lessee, agree to a lower royalty rate, of no less than 12½ percent of the value of all oil produced and removed or sold from the lease, subject to the Superintendent's approval. The Superintendent may only approve a lower royalty rate if it is determined to be in the best interest of the Osage Nation.

§ 226.37 Calculating the value of oil for royalty purposes.

(a) Unless the Osage Minerals Council elects to take royalty in kind under § 226.42, the value of oil for royalty purposes is the greater of the:

(1) NYMEX Calendar Month Average Price of oil at Cushing, Oklahoma, for the month in which the produced oil was removed or sold from the lease, adjusted for gravity using the scale set forth in § 226.38; or

(2) Actual selling price for the transaction, adjusted for gravity using the scale set forth in § 226.38.

(b) The applicable NYMEX Calendar Month Average Price will be published on ONRR's website at *https://www.onrr.gov*.

§ 226.38 Gravity adjustment for oil.

(a) The gravity adjustment of the NYMEX Calendar Month Average Price of oil at Cushing, Oklahoma under § 226.37(a) is a deduction from the price per barrel, as follows:

If the gravity of the oil is . . .	the rate is . . .	for each . . .
(1) At or between 40.0 and 44.9 degrees	zero	
(2) At or between 35.0 and 39.9 degrees	$0.02	degree or fraction thereof below 40.0.
(3) Below 35.0 degrees	$0.10 plus an additional $0.015	one-tenth of one degree below 35.0.
(4) Above 44.9 degrees	$0.015	for each one-tenth of one degree above 44.9.

(b) The Superintendent may, on or before the fifth calendar day of the month following production, publish a gravity adjustment scale for oil of gravity below 40.0 degrees or above 44.9 degrees that supersedes this section if they determine that such adjustments are warranted based on market conditions.

§ 226.39 Royalty rate for gas.

The lessee must pay to the Superintendent as royalty no less than 16⅔ percent of the value of all gas, including residue gas and gas plant products, produced and removed or sold from the lease. The Osage Minerals Council may, upon presentation of justifiable economic evidence by a lessee, agree to a lower royalty rate, of no less than 12½ percent of the value of all gas, including residue gas and gas plant products, produced and removed or sold from the lease, subject to the Superintendent's approval. The Superintendent will only approve a lower royalty rate if it is determined to be in the best interest of the Osage Nation.

§ 226.40 Calculating the value of gas for royalty purposes.

Unless the Osage Minerals Council elects to take royalty-in-kind under § 226.42, the value of production for royalty purposes is calculated by multiplying the measured volume of gas at the well (Mcf), times the heating value of the gas (MMBtu/Mcf), times the Monthly Index Zone Price of the gas ($/MMBtu) for Oklahoma Zone 1 published by ONRR on its website, *https://www.onrr.gov*. The heating value of the gas must be calculated and reported in accordance with §§ 226.140(a) and (b) and 226.141, respectively. If the Monthly Index Zone Price ceases to be published or is otherwise unavailable, the Superintendent must establish a comparable method for calculating the value of production. No deductions or allowances, whether monetary, volumetric, or otherwise, are allowed.

§ 226.41 Minimum royalty.

(a) If the royalty paid for a producing lease during any year is less than the amount of the annual rental for the lease, the lessee must pay minimum royalty.

(b) Minimum royalty in an amount equal to the annual rental specified for the lease less the amount of the royalty paid on production is due on or before the lease anniversary date.

(c) Failure to timely pay minimum royalty will result in the assessment of interest on all unpaid or underpaid minimum royalty amounts. Interest will be charged at the IRS underpayment rate pursuant to 26 U.S.C. 6621(a)(2), or such other rate as the Superintendent or ONRR may prescribe. The IRS underpayment rate is posted quarterly and is available online at *https://www.irs.gov*. Interest will be charged only for the number of days the payment is late.

(d) Minimum royalty payments must be paid to ONRR in accordance with the requirements set forth in § 226.43.

§ 226.42 Royalty-in-kind.

(a) The Osage Minerals Council may take oil and gas royalty-in-kind on a lease-by-lease basis or for all leases in Osage County.

(b) The Osage Minerals Council must provide the Superintendent and affected lessees with at least 30 calendar days' written notice of its decision to take royalty-in-kind and at least 60 calendar days' written notice of its decision to terminate royalty-in-kind. The Osage Minerals Council must submit resolutions to the Superintendent for its decisions to take and terminate royalty-in-kind.

(c) The Osage Minerals Council must take 100 percent of the daily royalty oil and royalty gas produced from all leases placed in royalty-in-kind status. Royalty oil and royalty gas must be taken in-kind at the wellhead. For purposes of this section, royalty oil and royalty gas mean the daily lease production multiplied by the royalty rate.

(d) Lessees must furnish free storage for royalty oil and royalty gas for 30 calendar days from the date of production. The Osage Minerals Council must negotiate agreements for the storage of royalty oil and royalty gas directly with lessees. The Superintendent will not negotiate, review, or approve royalty-in-kind storage agreements.

(e) All rights, duties, and obligations that exist under the terms and conditions of the lease and the regulations in this part remain in effect when royalty is taken in kind, including the lessee's obligation to pay advance annual rental and minimum royalty.

§ 226.43 Royalty payments.

(a) Royalty payments must be remitted to ONRR. The lessee or purchaser may remit royalty payments in accordance with § 226.44.

(b) Royalty payments are due on or before the last calendar day of the month following the month during which the oil or gas is produced and removed or sold and shall cover all volumes removed or sold for the preceding month. If the last calendar day of the month falls on a weekend or

Federal holiday, payments are due on the first business day of the next month.

(c) All royalty payments must be remitted using one of the forms of payment identified in § 226.8 unless ONRR specifies otherwise. Payment by EFT is preferred.

(d) Non-EFT royalty payments must be made payable to ''DOI–ONRR for BIA Osage Nation.'' Payments mailed via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO 80225–0627. Payments sent via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Entrance N–1, Room 332, 6th Avenue and Kipling Street, Denver, CO 80225.

(e) ONRR must receive royalty payments submitted by EFT in its account on or before the due date. ONRR must receive royalty payments submitted via U.S. Postal Service, courier, or overnight delivery service at the applicable address set forth in paragraph (d) of this section before 4 p.m. mountain time on the due date.

(f) Failure to timely and properly make royalty payments will result in the assessment of interest on all unpaid or underpaid royalty amounts. Interest will be charged at the IRS underpayment rate pursuant to 26 U.S.C. 6621(a)(2), or such other rate as the Superintendent or ONRR may prescribe. The IRS underpayment rate is posted quarterly and is available online at *https://www.irs.gov*. Interest will be charged only for the number of days the payment is late.

(g) A payor may recoup an overpayment through a recoupment on Form ONRR–2014 against the current month's royalties or other revenues owed on the same lease. For any month, a payor may not recoup more than 100 percent of the royalties or other revenues owed in that month. Overpayments subject to recoupment include all payments made in excess of the required payment for royalty, rental, bonus, or other amounts owed as specified by the terms and conditions of the lease, the regulations in this part, orders and notices the Superintendent or ONRR issue, and other applicable law. ONRR may order any payor not to recoup any amount for such reasonable period as may be necessary for ONRR to review the claimed overpayment.

§ 226.44 Royalty payment contracts and division orders.

(a) The lessee may enter into contracts or division orders with purchasers of oil and gas, or derivatives therefrom, that designate the purchaser as the party responsible for remitting royalty payments. The lessee must provide the Superintendent with a copy of the contract or division order evidencing such designation.

(b) A contract or division order does not relieve the lessee from responsibility for the payment of royalty or from responsibility for ensuring the accurate measurement and reporting of all oil and gas removed or sold from the lease. If the purchaser fails to pay or underpays royalty, the lessee is responsible for payment in full of all amounts due and owing, including any interest that may be assessed.

§ 226.45 Royalty reports.

(a) The lessee must submit a certified monthly royalty report to ONRR using Form ONRR–2014, Report of Sales and Royalty Remittance.

(b) ONRR must receive reports by 4 p.m. mountain time on or before the last calendar day of the month that follows the month during which the oil and gas is produced and removed or sold. If the last calendar day of the month falls on a weekend or Federal holiday, the report is due on the first business day of the next month.

(c) The lessee must submit Form ONRR–2014 electronically via ONRR's eCommerce Reporting website, *https://onrrreporting.onrr.gov,* unless they qualify for an exception under paragraph (d) of this section. The lessee must enter royalty data into the system manually or upload data files using the American Standard Code for Information Interchange (ASCII) or Comma Separated Values (CSV) file layout formats specified by ONRR. Detailed information regarding how to complete and submit Form ONRR–2014 is available at *https://www.onrr.gov/ReportPay/royalty-reporting.htm*.

(d) The lessee may submit Form ONRR–2014 manually if they:

(1) Have never reported to ONRR before, in which case they have three months from the date the first royalty report is due to begin reporting electronically;

(2) Are only reporting minimum royalty; or

(3) Are a small business, as defined by the Small Business Administration, and do not own a computer.

(e) Royalty reports submitted manually via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO, 80225–0627. Royalty reports submitted manually via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Entrance N–1, Room 332, 6th Avenue and Kipling Street, Denver, CO 80225. If a lessee who is submitting royalty reports manually has three or more late submissions, ONRR may issue an order requiring the lessee to submit all future royalty reports electronically.

§ 226.46 Requirements for royalty, rental, and payment records.

(a) The lessee must make, retain, and preserve accurate and complete records demonstrating that rental, royalty, and other payments relating to oil and gas leases comply with the terms and conditions of the lease, the regulations in this part, and applicable orders or notices. Such records include, but are not limited to, royalty and production reports; computer programs, automated files, and supporting systems documentation used to produce reports submitted to the Superintendent and ONRR; and relevant statements, receipts, run tickets, QTRs, contracts and agreements.

(b) The lessee must maintain and preserve records under this section for a minimum of six years from the date upon which the relevant transaction was recorded unless the Superintendent or ONRR provides written notice to the lessee that an audit or investigation is being conducted and the records must be maintained for a longer period. If an audit or investigation of the records is being conducted, the lessee must maintain the records until the Superintendent or ONRR issues a written release of such obligation.

(c) The lessee must make records available to the Superintendent and ONRR for inspection upon request. The lessee will be given a reasonable period of time to produce historical records.

§ 226.47 Right of the U.S. Government to purchase oil.

Any of the executive departments of the U.S. Government have the option to purchase all or any part of the oil produced from any lease under this part at no less than the price set forth in § 226.37.

Audits

§ 226.48 Audits and reviews.

ONRR may initiate and conduct audits and reviews relating to the scope, nature, and extent of lessees' and purchasers' compliance with rental, royalty, and other payment and reporting requirements under the terms and conditions of the lease, the regulations in this part, and applicable orders or notices.

Subpart G—Bonds

Lease Bonds

§ 226.49 Grandfathering of existing bonds.

(a) Existing $5,000 lease bonds filed with leases and assignments approved prior to [effective date of final rule] are exempt from §§ 226.51(b) and 226.53(a)(3).

(b) Existing $50,000 collective bonds filed with leases and assignments approved prior to [effective date of final rule] are exempt from §§ 226.52(a) and 226.53(a)(3).

(c) Existing lease and collective bonds will cover all unplugged wells located on the subject lease(s) that the lessee of record drilled and completed, operated, or controlled prior to [effective date of final rule] according to the Osage Agency's records. For purposes of this section, a lessee is considered to ''control'' all unplugged wells located on the lease that are recorded in the Osage Agency's plat book or that a purchaser exercising reasonable diligence could or should have known of at the time the lease or assignment was executed, except for orphan wells.

(d) Lessees with existing lease and collective bonds must file performance bonds that comply with the requirements set forth in this subpart for all wells they propose to drill, reenter, recomplete, and accept via assignment after [effective date of final rule].

(e) Existing lease and collective bonds will be considered an acceptable form of financial security for the lessee of record on [effective date of final rule] only. The right to maintain existing lease and collective bonds cannot be conveyed to any other person through assignment, a transfer of operating rights or working interests, or otherwise. All future lessees, including assignees, of leases with grandfathered lease or collective bonds must file performance bonds that comply with the requirements set forth in this subpart.

§ 226.50 Bond obligations.

(a) The lessee must file a performance bond conditioned upon compliance with the terms and conditions of the lease and the regulations in this part prior to drilling, reentering, and recompleting wells or accepting responsibility for wells through assignment. The lessee must also file a performance bond for all saltwater disposal (SWD) easements.

(b) Performance bonds must be in one of the following forms:

(1) Surety bond issued by a qualified surety company approved by the Department of the Treasury (see Department of the Treasury Circular No. 570);

(2) Certificate of deposit issued by a financial institution, the deposits of which are federally insured, explicitly granting the Superintendent the full authority to demand immediate payment in the event of default;

(3) Cashier's check;

(4) Certified check;

(5) Negotiable Treasury securities of the United States of a value equal to the amount specified in the bond and including a proper conveyance to the Superintendent of the full authority to sell such securities in the event of default; or

(6) Irrevocable letter of credit issued by a financial institution, the deposits of which are federally insured, for a specific term, identifying the Superintendent as the sole payee with full authority to demand immediate payment in the event of default and subject to the following requirements:

(i) The letter of credit must be issued by a financial institution organized or authorized to do business in the United States;

(ii) The letter of credit must be irrevocable during its term. A letter of credit used as security for any well(s) that have been drilled, but for which final approval of abandonment has not been given, shall be forfeited and collected by the Superintendent if not replaced by a suitable bond or letter of credit at least 30 calendar days before its expiration date;

(iii) The letter of credit must be payable to the Superintendent upon demand, in full or in part, upon receipt of a notice of attachment from the Superintendent stating the basis therefore (*e.g.,* default or failure to file a replacement in accordance with paragraph (c)(5)(ii) of this section);

(iv) The initial expiration date of the letter of credit must be at least one year following the date it is filed with the Superintendent; and

(v) The letter of credit must contain a provision for automatic renewal for periods of not less than one year in the absence of notice to the Superintendent at least 90 calendar days prior to the original or extended expiration date.

§ 226.51 Individual well bond requirements.

(a) After [effective date of final rule], individual performance bonds must be filed for:

(1) Each well the lessee proposes to drill, reenter, recomplete, or accept responsibility for through assignment; and

(2) Each SWD well under an approved SWD easement.

(b) Individual well bonds must be in the amount of not less than $6 per foot of the measured well depth for each existing well or the projected well depth for each proposed well.

(c) Individual well bonds must be filed with the permit application, executed assignment, or executed SWD easement.

§ 226.52 Countywide and nationwide bond requirements.

(a) In lieu of an individual well bond, the lessee may file a countywide bond in the amount of not less than $75,000 covering all leases of, and SWD easements within, the Osage Mineral Estate to which the lessee is, or may become, a party. The total lease acreage covered by a single countywide bond cannot exceed 10,240 acres.

(b) In lieu of individual well or countywide bonds, the lessee may file a $150,000 nationwide bond covering all leases to which the lessee is, or may become, a party in the United States and all SWD easements to which the lessee is, or may become, as party within the Osage Mineral Estate.

(c) Countywide and nationwide bonds must be filed with the executed lease, assignment, or SWD easement.

§ 226.53 Authorization to increase the required bond amount.

(a) The Superintendent may require an increase in the amount of any bond, including grandfathered bonds, if the:

(1) The lessee defaults on an obligation incurred under the lease, approved permits, the regulations in this part, or applicable orders and notices;

(2) The lessee is deemed high risk due to a history of lease violations in Osage County; enforcement action by other Federal or state agencies; unpaid royalties, civil penalties, or other amounts due and owing; or other factors; or

(3) The total estimated cost of plugging existing wells exceeds the present bond amount.

(b) The Superintendent may increase the bond amount to any level, but in no circumstances will the bond amount exceed the sum of the amounts owed for prior violations that remain outstanding, the amount of uncollected royalties or other amounts due, and the total estimated costs of plugging.

§ 226.54 Bond forfeiture.

(a) The Superintendent may call for forfeiture of all or part of a performance bond if the lessee defaults on, refuses to comply with, or otherwise fails to satisfy an obligation incurred under a lease, approved permit, the regulations in this part, or applicable notices and orders.

(b) Where the surety makes payment to the Superintendent due to default, the face amount of the bond and the surety's liability thereunder will be reduced by the amount of such payment.

(c) If the value of the bond is reduced due to default, and the obligation in default is less than or equal to the face amount of the bond, the lessee must either restore the existing bond or post a new bond. If the obligation in default exceeds the face amount of the bond, the lessee must make full payment to the BIA for all costs incurred that are in excess of the face amount of the bond and must post a new bond. If the lessee fails to make full payment for all such obligations, the United States or Osage Minerals Council may take action to recover from the lessee all costs in excess of the amount collected under the bond. The United States has sole discretion regarding whether to take action to recover costs and nothing in this section will be construed as imposing an obligation on the United States to take such action.

(d) The lessee must restore the existing bond or post a new bond under paragraph (c) of this section within six months of receiving the notice of default, or such shorter period as the Superintendent may specify.

(e) Failure to restore or replace a deficient bond may subject the lease(s) of, and SWD easements within, the Osage Mineral Estate covered by the bond to cancellation under § 226.165.

§ 226.55 Termination of the period of liability and release of bonds.

(a) The Superintendent will not terminate the period of liability or release a bond unless an acceptable replacement bond has been filed or all obligations incurred under the lease, approved permits, regulations in this part, and applicable notices and orders have been satisfied.

(b) Termination of the period of liability ends the period during which obligations accrue but does not relieve the surety of responsibility for obligations that accrued during the period of liability. Release of the bond relieves the surety of all liability.

Geophysical Exploration Bonds

§ 226.56 Geophysical exploration bond requirements.

(a) Lessees and permittees must file a bond conditioned on compliance with the terms and conditions of the geophysical exploration permit and the regulations in this part prior to commencing exploration operations. The bond must be in one of the forms identified in § 226.50(b).

(b) A lessee holding a valid lease of the Osage Mineral Estate under this part for which the required performance bond has been posted, may conduct geophysical exploration operations on the covered lease without further bonding.

(c) A lessee holding a valid lease of the Osage Mineral Estate for which an individual well bond has been posted who wishes to explore unleased lands, must post a geophysical exploration bond in accordance with paragraph (d) of this section. A lessee holding a valid lease of the Osage Mineral Estate for which a countywide or nationwide bond has been posted who wishes to explore unleased lands, may obtain a bond rider to include geophysical exploration operations.

(d) Individual exploration bonds in the amount of $5,000 must be filed with each geophysical exploration permit. In lieu of individual exploration bonds, lessees and permittees may file a countywide bond in the amount of $25,000 covering all exploration operations within Osage County or a nationwide bond in the amount of $50,000 covering all exploration operations within the United States.

§ 226.57 Bond forfeiture.

The Superintendent may call for forfeiture of all or part of the bond posted for geophysical exploration operations if the lessee or permittee defaults on, refuses to comply with, or otherwise fails to satisfy an obligation incurred under the geophysical exploration permit, the regulations in this part, or applicable notices and orders.

§ 226.58 Termination of the period of liability and release of bonds.

(a) The Superintendent will not terminate the period of liability or release a geophysical exploration bond unless all obligations incurred under the geophysical exploration permit and the regulations in this part have been satisfied.

(b) Terminating the period of liability ends the period during which obligations accrue but does not relieve the surety of responsibility for obligations that accrued during the period of liability. Release of the bond relieves the surety of all liability.

Subpart H—Operations

General Requirements

§ 226.59 Conduct of operations.

(a) Lessees and permittees must comply with the terms and conditions of the lease and approved permits, the regulations in this part, orders and notices the Superintendent issues, and all other applicable laws and regulations in the conduct of all operations.

(b) Lessees and permittees must conduct all exploration, testing, development, production, and other operations in a safe and workmanlike manner that:

(1) Protects the leased or permitted lands and improvements thereon;

(2) Protects natural resources, cultural resources, and environmental quality;

(3) Protects health and safety;

(4) Ensures proper management, measurement, disposition, and security of production; and

(5) Results in the maximum ultimate recovery of oil and gas with minimum waste and minimal adverse effect on the recovery of other mineral resources.

(c) Lessees and permittees must not commit waste on leased or permitted lands, nor allow avoidable nuisance to be maintained thereon.

(d) Lessees and permittees must use and maintain all installations and equipment in a manner that ensures structural and mechanical integrity, proper function, and the safe conduct of operations at the location of the installation or equipment.

(e) Lessees and permittees must comply with the National Electrical Code in the installation, operation, maintenance, and use of all electrical lines.

§ 226.60 Inspection of operations.

(a) The Superintendent has the right to enter or travel across any lands covered by a lease or permit for the purpose of conducting an inspection or investigation.

(b) The Superintendent may conduct inspections and investigations with or without advance notice to the lessee or permittee. Inspections and investigations may take place at any time but will normally be conducted during those hours when responsible persons are expected to be present at the site being inspected or investigated.

(c) Lessees and permittees must allow the Superintendent to inspect and investigate:

(1) Lands covered by the lease or permit;

(2) Operations; and

(3) Improvements, facilities, structures, fixtures, and equipment located on leased or permitted lands and any records of design, construction, maintenance, or repairs relating thereto.

Commencement of Operations

§ 226.61 No operations may commence prior to approval of a lease or geophysical exploration permit.

No operations may commence on any tract of land until the Superintendent approves a lease or geophysical exploration permit covering such land.

§ 226.62 Prior authorization required to commence operations on trust or restricted lands.

(a) No operations are permitted on trust or restricted lands without the Superintendent's approval.

(b) If an Indian landowner is unwilling to allow the commencement of operations on their lands, the Superintendent will conduct an examination of the lands with the Indian landowner and lessee or permittee. If the Superintendent determines that the interests of the Osage Nation require that the lands be developed or explored, they will instruct the parties to reach an agreement under which operations may be conducted.

(c) If the Indian landowner and lessee or permittee cannot reach an agreement under paragraph (b) of this section, the parties must present the matter to the Osage Minerals Council, which will issue a written recommendation. The Osage Minerals Council's recommendation will be considered final and binding upon the Indian landowner and lessee or permittee. A guardian or authorized representative may represent the Indian landowner before the Osage Minerals Council. If no such guardian or authorized representative exists, or where the Superintendent determines that there is no proper party to speak for an Indian landowner of unsound mind, the Principal Chief of the Osage Nation will represent the Indian landowner.

(d) If the Indian landowner or their guardian or authorized representative fails to appear before the Osage Minerals Council as required, or the Osage Minerals Council fails to act within 10 calendar days after the matter is referred for recommendation, the Superintendent may authorize the lessee or permittee to proceed with operations.

§ 226.63 Notice and information to be given to surface owners prior to commencement of operations.

(a) The lessee or permittee must meet with the surface owner prior to the commencement of any operations on leased or permitted lands, except for archeological or biological surveying and the staking of wells.

(b) For operations other than those identified in paragraph (a) of this section, the lessee or permittee must send the surface owner a written request for a meeting by certified mail. The meeting must be held at least 10 calendar days prior to the commencement of operations unless the Superintendent waives such requirement, or the parties agree otherwise. At the meeting, the lessee or permittee must:

(1) Indicate the location of the well(s), shot holes to be drilled, or seismic survey site;

(2) Arrange for a route of ingress and egress. If the lessee or permittee and surface owner fail to agree on a route of ingress and egress, the Superintendent will set the route; and

(3) Provide the name and address of the representative upon whom the surface owner must serve any claim for damages that may be sustained from operations and the procedure for the settlement of such claims as set forth in § 226.83.

(c) Where operations will occur on trust or restricted land, the lessee or permittee must conduct the meeting required under paragraph (b) of this section with the Superintendent and, if possible, the Indian landowner.

(d) If the surface owner cannot be contacted at their last known address or has not accepted the meeting request within 30 calendar days of receipt thereof, the Superintendent will authorize the lessee or permittee to commence operations.

§ 226.64 Payment of commencement money and tank siting fees to the surface owner.

(a) Prior to commencing drilling, reentry, or geophysical exploration operations, the lessee or permittee must pay the surface owner commencement money in the amount of:

(1) $1,500 per well to be drilled or reentered;

(2) $25 per seismic shot hole; and

(3) $12 per acre, or fraction thereof, occupied by the lessee or permittee while conducting a seismic survey.

(b) The lessee must pay the surface owner $200 per tank for each tank to be sited on the leased lands, except for tanks temporarily set on well sites for drilling, completion, or testing purposes only.

(c) Commencement money and tank siting fees must be paid in full prior to the commencement of operations or siting of tanks on the lease, subject to the exception set forth in paragraph (e) of this section.

(d) Where the surface estate is trust or restricted land, commencement money and tank siting fees must be paid to the Superintendent for the Indian landowner.

(e) Where the surface estate is not trust or restricted land, commencement money and tank siting fees must be paid to the surface owner directly. If the surface owner is not a resident of Osage County, such payment must be sent by certified mail to the surface owner's last known address. If the payment is returned as undeliverable or the surface owner refuses to accept the payment, the commencement money or tank siting fees will be deemed forfeited. Nothing herein affects the surface owner's right to the settlement of surface damages under §§ 226.82 and 226.83.

(f) Commencement money and tank siting fees are a credit toward the settlement of surface damages. The surface owner's acceptance of commencement money and tank siting fees does not affect their right to compensation for damages occasioned by operations. A settlement covering the actual surface damages resulting from drilling, reentry, or geophysical exploration operations does not need to be paid until such operations are complete.

Drilling, Workover, and Well Abandonment Operations

§ 226.65 Use of surface lands and water for operations.

(a) The lessee has the right to use so much of the surface of the leased lands as may be reasonable for the development, extraction, marketing, and sale of oil and gas. The right to use the surface lands includes the right-of-way for ingress and egress to any point of operations. The right to surface lands also includes, but is not limited to, the right to install and maintain pipelines, electric lines, and other necessary equipment and facilities. The Superintendent will determine the routing of pipelines and electric lines, as well as the siting of equipment and facilities of the lessee and surface owner are unable to agree.

(b) Drilling sites must be held to the minimum area essential for operations and must not exceed the acreage set forth in the approved EA unless the Superintendent authorizes such expansion in writing.

(c) The lessee may use water from natural water courses for approved lease operations, provided that such use does not diminish the supply below the requirements of the surface owner from whose land the water is taken.

(d) The lessee may use water from reservoirs formed by the impoundment of water from natural water courses for approved lease operations, provided that such use does not exceed the quantity to which the lessee would originally have been entitled had the reservoirs not been constructed.

(e) The lessee may install necessary lines and other equipment within the

Osage Mineral Estate to obtain water in accordance with paragraphs (c) and (d) of this section. If any such installation will be over or across surface lands that are held in trust or restricted status, the lessee must obtain a right-of-way pursuant to part 169 of this title prior to commencing the necessary installation operations. Any damages resulting from installations to obtain water must be settled as provided in § 226.83.

§ 226.66 Drilling operations.

(a) The lessee must submit an Application for Permit to Drill, together with any required information or documentation, for each well to be drilled or reentered. No drilling or reentry operations, or surface disturbance preliminary thereto, may commence prior to the Superintendent's approval of the permit.

(b) The Superintendent will not accept an application for a permit to drill unless it is administratively complete.

(c) The lessee must notify the Superintendent of planned drilling or reentry operations at least five business days prior to the commencement thereof. The Superintendent may witness such operations without advance notice.

(d) The lessee may not drill, or conduct surface disturbance preliminary to drilling, within 300 feet of the boundary line of leased lands without the Superintendent's approval. The lessee may not locate a well or tank within 200 feet of any Federal, state, county, or municipal road or highway that is owned and maintained for public use; any intermittent, ephemeral, or perennial streams or water sources; or any building used as a residence, granary, or barn without the Superintendent's approval. Failure to obtain such approval will result in the assessment of civil penalties under § 226.161 and the issuance of an order to immediately plug the well or remove the tank(s) and may subject the lease to cancellation under § 226.165.

(e) The lessee must submit a subsequent Well Completion or Reentry Report following drilling and reentry operations in accordance with § 226.74(c) through (g).

§ 226.67 Well control.

(a) *Drilling wells.* The lessee must take the necessary precautions to keep wells under control and must use and maintain materials and equipment necessary to ensure the safety of operating conditions and procedures.

(b) *Vertical drilling.* The lessee must conduct drilling operations in a manner that prevents the completed well from deviating significantly from the vertical unless the Superintendent's prior approval of such deviation is obtained. The lessee must promptly report any well that deviates significantly from the vertical without prior approval to the Superintendent and conduct a directional survey. For purposes of this section, significant deviation means a projected deviation of the well bore from the vertical of 10 degrees or more or a projected bottom hole location that may be less than 300 feet from the lease boundary.

(c) *High pressure or loss of circulation.* The lessee must take immediate steps to maintain or restore control of any well in which the pressure equilibrium becomes unbalanced.

§ 226.68 Use of gas for artificial lifting of oil.

A lessee with an oil-only lease executed prior to [effective date of final rule] is prohibited from using gas from a distinct or separate stratum for the purpose of flowing or lifting oil. A lessee with a combined oil and gas lease may use gas from a distinct or separate stratum for the purpose of flowing or lifting oil subject to the requirements set forth in §§ 226.144 through 226.151.

§ 226.69 Workover operations.

(a) The lessee must submit an Application for Permit to Workover Wells, together with any required information or documentation, for each well to be worked over. The following workover operations, and surface disturbance preliminary thereto, may not commence prior to the Superintendent's approval of the permit:

(1) Recompletion;

(2) Deepening, plugging back, or converting a well;

(3) Formation treatments and acidizing jobs, including acid fracturing;

(4) Hydraulic fracturing; and

(5) Pulling or altering the casing.

(b) The Superintendent will not accept an application for a workover permit unless it is administratively and technically complete.

(c) The lessee must notify the Superintendent of planned recompletion, deepening, and hydraulic fracturing operations at least five business days prior to the commencement thereof. The lessee does not need to provide notice prior to commencement of the other workover operations identified in paragraph (a) of this section. The Superintendent may witness any workover operations without advance notice.

(d) The lessee must submit a subsequent Report of Workover Operations following all workover operations identified in paragraph (a) of this section in accordance with § 226.74(c) through (g).

(e) Prior approval and a subsequent report of operations are not required for well cleanout work, well maintenance, or bottom hole pressure surveys. The operations listed in paragraph (a) of this section do not qualify as well cleanout work or well maintenance.

§ 226.70 Requirements for operations in Hydrogen Sulfide (H_2S) areas.

(a) *Testing requirements.* (1) The lessee must conduct an initial test of the H_2S concentration of the gas stream for each well and production facility completed and make the results of such test(s) available to the Superintendent upon request.

(2) The lessee must determine the radius of exposure for each well and production facility having an H_2S concentration of 100 ppm or more in the gas stream and submit a report of such calculations to the Superintendent. The radius of exposure must be calculated as follows:

(i) For determining the 100-ppm radius of exposure where the H_2S concentration in the gas stream is less than 10 percent:

$$X = [(1.589)(H_2S\ Concentration)(Q)]^{(0.6258)}$$

(ii) For determining the 500-ppm radius of exposure where the H_2S concentration in the gas stream is less than 10 percent:

$$X = [(0.4546)(H_2S\ Concentration)(Q)]^{(0.6258)}$$

Where:

X = radius of exposure in feet

H_2S Concentration = decimal equivalent of the mole or volume fractions of the H_2S in the gaseous mixture

Q = maximum volume of gas determined to be available for escape, or escape rate, in cubic feet per day (at standard condition of 14.73 psia and 60 °F)

(iii) For determining the 100-ppm or 500-ppm radius of exposure where the H_2S concentration in the gas stream is 10 percent or greater, the lessee must use an air dispersion model approved by the EPA, or such another method the Superintendent approves.

(3) The lessee must calculate the radius of exposure pursuant to paragraph (a)(2) of this section for each well and production facility completed prior to [effective date of final rule] that has a H_2S concentration of 100 ppm or greater in the gas stream and submit a report of such calculations to the Superintendent on or before [six months from effective date of final rule].

(4) If a change in operations or production results in an increase in the H_2S concentration or radius of exposure of five percent or more as calculated pursuant to paragraph (a)(2) of this section, the lessee must notify the Superintendent in writing of such increase within 60 calendar days of identification of the change.

(b) *Public protection.* (1) The lessee must report any release of a potentially hazardous volume of H_2S to the Superintendent as soon as practicable, but not later than 24 hours following identification of the release.

(2) The lessee must submit a Public Protection Plan providing a detailed plan of action for alerting and protecting the public in the event of a release of a potentially hazardous volume of H_2S when any of the following conditions apply:

(i) The 100-ppm radius of exposure is greater than 50 feet and includes any part of a residence, school, church, place of business, or other area the public can reasonably be expected to frequent;

(ii) The 500-ppm radius of exposure is greater than 50 feet and includes any part of a Federal, state, county, or municipal road or highway that is owned and maintained for public use; or

(iii) The 100-ppm radius of exposure is greater than or equal to 3,000 feet.

(3) The details of the Public Protection Plan may vary according to site-specific characteristics expected to be encountered and the proximity and density of the population at risk. All plans must include the following:

(i) The lessee's name and phone number;

(ii) The names, phone numbers, and responsibilities of key personnel;

(iii) The names and phone numbers of residents within the radius of exposure;

(iv) The names and phone numbers of the responsible parties for each of the schools, churches, businesses, roads, highways, or other public areas or facilities within the radius of exposure;

(v) A call list including the Osage Agency, Osage Minerals Council, Federal and state regulatory agencies, local law enforcement, local fire departments, and other public safety personnel;

(vi) Instructions and procedures for notifying the Osage Agency, Osage Minerals Council, and public of an emergency;

(vii) Instructions and procedures for notifying Federal and state regulatory agencies, local law enforcement, local fire departments, and public safety personnel of an emergency and requesting their response;

(viii) A plat showing the location of residences, schools, churches, places of business, roads, highways, or other areas the public may reasonably be expected to frequent within the radius of exposure;

(ix) Advance briefing of residences, schools, and churches within the 100-ppm radius of exposure. Advance briefing may be conducted in-person or by certified letter and must provide:

(A) Information regarding the characteristics and hazards of H_2S and SO_2;

(B) A list of possible sources of H_2S and SO_2 within the radius of exposure;

(C) Detailed instructions for reporting a gas leak to the lessee;

(D) Information regarding the necessity of having an emergency action plan;

(E) The way the public will be notified of an emergency; and

(F) The steps that should be taken in the event of an emergency;

(x) The title(s) or position(s) of the individuals authorized by the lessee to ignite escaping gas, circumstances under which those individuals may ignite escaping gas, and way in which escaping gas will be ignited;

(xi) Procedures for monitoring H_2S and SO_2 levels and wind direction, maintaining site security, controlling access to the affected site, and implementing any other measures necessary to monitor the situation and protect the public until the release is contained; and

(xii) A description of the detection system(s) that will be used to determine the concentration of H_2S released in the event of a release from a production facility.

(4) The Public Protection Plan must be activated immediately upon detection of the release of a potentially hazardous volume of H_2S. The lessee must notify the Superintendent of activation of the Public Protection Plan.

(5) A copy of the Public Protection Plan must be maintained at the well site, production facility, or such other location on the lease that the plan is readily accessible if activation is required.

(6) The lessee must review the Public Protection Plan on an annual basis and submit any revisions to the Superintendent.

(c) *Operating requirements for drilling, completion, and workover operations.* (1) If the lessee encounters zones containing H_2S concentrations in excess of 100 ppm while drilling with air, gas, mist, or other non-mud circulating mediums for aerated mud, the well must be killed with water-based or oil-based drilling mud, and thereafter, mud must be used as the circulating medium for continued drilling.

(2) A flare system meeting the following requirements must be installed to safely gather and burn H_2S-bearing gas:

(i) Flare lines must be located as far from the operating site as feasible and must compensate for changes in wind direction;

(ii) Flare lines must be straight unless targeted with running tees; and

(iii) The flare system must be equipped with a safe means of ignition.

(3) The lessee must check the SO_2 level in the flare impact area using portable detection equipment at any site where SO_2 may be released due to the flaring of H_2S during drilling, completion, or workover operations. The lessee must implement the Public Protection Plan if the flare impact area reaches a sustained ambient threshold of 2 ppm or greater of SO_2 in air and includes any part of a residence, school, church, place of business, or other area the public can reasonably be expected to frequent.

(4) The lessee must install a remote-controlled choke or valve for all H_2S drilling operations and, where feasible, completion operations.

(d) *H_2S training and safety requirements.* (1) The lessee must provide appropriate H_2S training for all personnel including, but not limited to, training regarding:

(i) The hazards and characteristics of H_2S;

(ii) The effect of H_2S on metal components of the well system;

(iii) The operation of safety equipment;

(iv) First aid procedures in the event of exposure; and

(v) Emergency response procedures and evacuation routes if there is a release of a potentially hazardous volume of H_2S.

(2) The lessee must ensure that the following safety equipment is available for use on the lease and maintained in good working condition:

(i) Protective breathing apparatus for personnel;

(ii) Communication devices that can be used with protective breathing apparatus; and

(iii) A flare gun and flares to ignite the well.

(3) Each drilling and well completion site must have an H_2S detection and monitoring system that automatically activates audible and visible alarms when the ambient air concentration of H_2S reaches 10 ppm. The system must have rapid response sensors capable of sensing a minimum of 10 ppm of H_2S

in ambient air, with at least three sensing points located at the shale shaker, rig floor, and bell nipple for a drilling site, and the cellar, rig floor, and circulating tanks or shale shaker for a well completion site. During workover operations, one sensing point must be located as close as possible to the wellbore. The lessee must maintain a record of all tests of the H_2S monitoring system and make such records available to the Superintendent upon request.

(4) The lessee must install at least one wind direction indicator at a location that is visible at all times during drilling, completion, and workover operations.

(5) The lessee must display a red flag at the entrance to the well or production facility site when H_2S is detected in excess of 10 ppm at any detection point.

(6) The lessee must post danger or caution signs on all roads and controlled access routes to the well or production facility site. The lessee must post a danger or caution sign a minimum of 200 feet, but no more than 500 feet, from the well or production facility site at a location that allows vehicles to turn around at a safe distance. Signs must meet the following requirements:

(i) Signs must be prominently displayed, legible, and large enough to be read from the road or entrance to the site;

(ii) Signs must be visible to all personnel and members of the public approaching the site under normal lighting and weather conditions;

(iii) Signs must read ''Danger—Poison Gas—Hydrogen Sulfide'' or ''Caution—Poison Gas May Be Present—H_2S;'' and

(iv) Signs must be painted high-visibility red, white, and black, or yellow and black.

(7) Storage tanks that are utilized as part of production operations and are operated at or near atmospheric pressure, where the vapor accumulation has an H_2S concentration of 500 ppm or greater in the tank, are subject to the following requirements:

(i) All stairs and ladders leading to the top of the storage tank must be chained and marked to restrict entry;

(ii) The lessee must install at least one wind direction indicator at the storage tank site; and

(iii) The lessee must post a danger or caution sign on the storage tank or within 50 feet thereof. The sign must comply with the requirements set forth in paragraphs (c)(6)(i) through (iv) of this section.

(8) Production facilities with a H_2S concentration of 100 ppm or greater in the gas stream are subject to the following requirements:

(i) The lessee must install at least one wind direction indicator at the production facility site. If the production facility and storage tank(s) are located at the same site, only one indicator is required;

(ii) The lessee must post a danger or caution sign within 50 feet of the production facility. The sign must comply with the requirements set forth in paragraphs (c)(6)(i) through (iv) of this section. If the facility is fenced, the sign may be posted on the gate; and

(iii) The lessee must post danger or caution signs at each location where a well flowline or lease gathering line crosses lease or public roads. The signs must be posted on each side of the road, as close to the pipeline as possible, and must contain the name of the lessee and a 24-hour phone number.

(9) The lessee must install automatic safety valves or shutdowns at the wellhead, or other appropriate shut-in controls for wells equipped with artificial lift, where the H_2S 100-ppm radius of exposure includes any part of a residence, school, church, place of business, or other area the public may be reasonably expected to frequent. Such valves must be set to activate upon the release of a potentially hazardous volume of H_2S.

(10) All equipment that has the potential to be exposed to H_2S must be suitable for the H_2S working environment.

§ 226.71 Surveys, samples, and tests.

(a) The Superintendent may require the lessee to conduct tests, run logs, and take any other surveys necessary to determine the following during the drilling and completion of a well:

(1) The presence, quantity, and quality of oil and gas;

(2) The presence and quality of water;

(3) The amount and direction of deviation of any well from the vertical; and

(4) The formations drilled and relevant characteristics of the oil and gas reservoirs penetrated.

(b) After a well is completed, the lessee must conduct periodic well tests to determine the quality and quantity of the oil, gas, and water. The Superintendent may determine the method and frequency of such tests.

(c) The Superintendent may require the lessee to conduct reasonable tests of the mechanical integrity of downhole equipment.

§ 226.72 Temporary abandonment.

A lessee may not temporarily abandon, shut down, or otherwise discontinue the use or operation of any producing well for more than 30 calendar days without the Superintendent's prior approval. The lessee must submit a request for temporary abandonment to the Superintendent in writing, together with any relevant supporting documentation, for each well to be temporarily abandoned. Wells cannot be temporarily abandoned prior to the Superintendent's approval of such request.

§ 226.73 Permanent plugging and abandonment operations.

(a) A lessee may not permanently abandon a newly completed or recompleted well unless oil and gas is not encountered in paying quantities.

(b) A lessee may not permanently abandon a producing well without the Superintendent's approval.

(c) The lessee must promptly plug dry and permanently abandoned wells in a manner that protects formations bearing fresh water, saltwater, oil, gas, and other minerals.

(d) The lessee must submit an Application for Permit to Plug Wells, together with evidence that the well is no longer capable of producing in paying quantities, proposed plugging instructions, and any other required information or documents, for each well to be permanently plugged and abandoned. No plugging and abandonment operations may commence prior to the Superintendent's approval of the permit.

(e) The Superintendent will not accept an application for a plugging permit unless it is administratively and technically complete.

(f) The lessee must notify the Superintendent of planned plugging operations at least five business days prior to the commencement thereof. The Superintendent may witness such operations without advance notice.

(g) The lessee must submit a subsequent Report of Plugging Operations in accordance with § 226.74(c) through (g).

(h) Upon written agreement with the surface owner, the lessee may condition a well that is being plugged and abandoned for use as a fresh water supply source for the surface owner. The lessee must file a copy of any such agreement with the Superintendent. The surface owner assumes all risk for the use of a reconditioned well as a fresh water supply source.

§ 226.74 Well records and reports.

(a) The lessee must keep accurate and complete records for all lease operations and submit reports thereof as required by the Superintendent and the regulations in this part. The lessee must make all books and records available to the Superintendent for inspection upon request.

(b) Records for operations including, but not limited to, the drilling, reentry, recompletion, deepening, repair, conversion, plugging and abandonment of all wells must show:

(1) All formations penetrated, the content and character of the oil, gas, and water in each formation, and the kind, weight, size, landed depth, and cement record of casing used;

(2) The record of drill-stem and other bottom hole pressure or fluid sample surveys, temperature surveys, directional surveys, or reports;

(3) The materials and procedures used in the treating or plugging of wells or the preparation of wells for temporary abandonment; and

(4) Any other information obtained during well operations.

(c) The lessee must submit the following to the Superintendent within 10 calendar days after the completion of operations on any well, or any required sampling, testing, or surveying thereof:

(1) A subsequent report of operations on the required form;

(2) A copy of the results of all samples, tests, and surveys required under this subpart;

(3) A copy of the electrical, mechanical, and radioactive logs or any other surveys of the well bore; and

(4) The core analysis obtained from the well, if available.

(d) For plugging operations, the lessee must submit copies of all cementing service tickets together with the subsequent report of operations.

(e) For hydraulic fracturing operations, the lessee must submit the following information together with the subsequent report of operations:

(1) The total volume of water used;

(2) The total volume of base fluid used;

(3) The type of base fluid used;

(4) The trade name, supplier, general purpose, ingredients, Chemical Abstract Service (CAS) Number, and maximum ingredient concentration in the hydraulic fracturing fluid (percent by mass), for each chemical additive or other substance added to the base fluid or, if such chemical identity information is withheld under paragraph (f) of this section, the generic chemical name or a similar descriptor for the chemical;

(5) The actual, estimated, or calculated fracture length, height, and direction;

(6) The actual measured depth of perforations and shots per foot or the open-hole interval; and

(7) The total volume of fluid recovered between completion of the last stage of the hydraulic fracturing operation and the point at which the lessee begins reporting water produced from the well to ONRR.

(f) If the lessee or owner of the information claims that any information that must be reported under paragraph (e) of this section is exempt from public disclosure, the information may be withheld. If information is withheld, the lessee must submit a Withholding of Proprietary Hydraulic Fracturing Information form with the report.

(g) The Superintendent may require a lessee to submit any information withheld under paragraph (f) of this section. The Superintendent will maintain the confidentiality of the information unless they determine that the information is not exempt from public disclosure. The Superintendent will provide the lessee with written notice of any such determination.

(h) The lessee must maintain and preserve records and reports required under this section for six years from the date they were generated, unless the Superintendent provides written notice to the lessee that an audit or investigation is being conducted and the records must be maintained for a longer period. If an audit or investigation of the records is being conducted, the lessee must maintain the records until the Superintendent issues a written release of such obligation.

§ 226.75 Well and facility identification.

(a) The lessee must properly identify each well located on the lease, excluding those wells that have been permanently abandoned, by a sign placed in a conspicuous location. The well sign must include the well number, lessee's name, lease name, lease number, and legal description.

(b) The lessee must mark each permanently abandoned well located on the lease with a permanent monument containing the information required under paragraph (a) of this section. The Superintendent reserves the right to waive the requirement for a permanent monument.

(c) The lessee must properly identify all facilities at which oil and gas produced from a lease is stored, measured, or processed by a sign placed in a conspicuous location. The sign must include the lessee's name, lease name, lease number, and legal description.

(d) All signs required by this section must be maintained in legible condition.

§ 226.76 Pollution prevention.

The lessee or permittee must take measures to prevent the unauthorized discharge of pollutants and migration of oil, gas, saltwater, or other deleterious substances to fresh water or other mineral bearing formations during the exploration, development, production, and transportation of oil and gas. The lessee or permittee must conduct tests and surveys of the effectiveness of the measures taken to ensure the protection of fresh water and mineral bearing formations and make the results of such tests available to the Superintendent upon request.

§ 226.77 Storage and disposal of fluids.

(a) Pits for drilling mud and deleterious substances used in the drilling, completion, recompletion, workover, or plugging of any well must be constructed and maintained to prevent the pollution of surface and subsurface fresh water. The lessee must routinely inspect and maintain pits to ensure that there is no fluid leakage into the environment.

(b) Pits constructed after [effective date of final rule] may not be located:

(1) In areas subject to frequent flooding according to the USDA Natural Resources Conservation Service (NCRS) Soil Survey;

(2) Within 300 feet of intermittent or ephemeral streams or water sources; or

(3) Within 500 feet of perennial streams, springs, fresh water sources, or wetlands.

(c) Pits may not be constructed, utilized, enlarged, or relocated without the Superintendent's prior approval.

(d) Immediately after the completion of operations, pits must be emptied and leveled as the Superintendent directs or as provided by written agreement with the surface owner. The lessee must file a copy of any surface owner agreement with the Superintendent.

(e) All produced water must be disposed of by injection into the subsurface, collection in approved pits, or other methods the Superintendent authorizes.

(f) Land application of water-based fluids from pits, tanks, and containment vessels; waste oil; waste oil residue; crude oil contaminated soil; freshwater drill cuttings; drilling mud; and other deleterious substances is not permitted upon any lease without the Superintendent's prior approval.

§ 226.78 Removal of fire hazards.

Any material that may constitute a fire hazard must be moved to a safe distance from the well site, tanks, and other surface facilities. Waste oil must be burned or disposed of in a matter that prevents creation of a fire hazard.

Geophysical Exploration Operations

§ 226.79 Applying for a geophysical exploration permit.

(a) Any party wishing to conduct oil and gas geophysical exploration activities on leased or unleased tracts of the Osage Mineral Estate must submit an Application for Oil and Gas Geophysical Exploration Permit and obtain the Superintendent's approval thereof prior to commencing exploratory operations or any surface disturbance preliminary thereto.

(b) Upon approval of an application, the Superintendent will issue a geophysical exploration permit that includes the terms and conditions deemed necessary to protect mineral resources and other resource values. The permit does not grant the permittee any option or preference rights to a lease of the subject lands or authorize the production, extraction, removal, or sale of oil, gas, or other mineral resources therefrom.

§ 226.80 Commencement of operations.

Permittees must notify the Superintendent of planned geophysical exploration operations at least five business days prior to the commencement thereof. The Superintendent may witness any such activities without advance notice.

§ 226.81 Records and reports.

Within 30 calendar days after the completion of geophysical exploration operations, the permittee must submit a subsequent Oil and Gas Geophysical Exploration Report.

Settlement of Surface Damages

§ 226.82 Lessee or permittee required to settle surface damages.

(a) The lessee or permittee must pay for damages to growing crops, improvements on the land, and all other surface damages occasioned by operations.

(b) In the settlement of surface damages on unrestricted lands, all sums due and payable must be paid to the surface owner. The surface owner must apportion damages among the parties having legal interests in the surface as the parties mutually agree or as their interests dictate. Parties having legal interests in the surface include, but are not limited to, owners, tenants, and surface lessees.

(c) In the settlement of damages on restricted lands, all sums due and payable must be paid to the Superintendent. The Superintendent will apportion damages among the surface owner, tenants, and surface lessees of record and credit the surface owner's account with the amount of damages apportioned.

(d) Any person claiming an interest in leased trust or restricted lands and damages thereto must notify the Superintendent, in writing, of the interest claimed and provide any documentation the Superintendent requests in support thereof. Failure to submit a written statement or the required supporting documentation to the Superintendent constitutes a waiver of notice and bars that person from asserting a claim for any portion of surface damages after such damages have been disbursed.

§ 226.83 Procedure for settlement of surface damages.

If a surface owner, tenant, or surface lessee suffers damages due to oil and gas exploration or development operations, the procedure for recovery is as follows:

(a) The aggrieved party or parties must serve written notice upon the lessee or permittee as soon as possible after the discovery of any damages. The written notice must describe the nature and location of the alleged damages, date of occurrence, name of the party or parties that caused the damages, and amount of the damages. This requirement does not limit the time within which any action must be brought in a court of competent jurisdiction to less than the 90-day period allowed by section 2 of the Act of March 2, 1929 (45 Stat. 1478, 1479).

(b) If the alleged damages are not adjusted at the time that written notice is served, the lessee or permittee must try to adjust the claim with the aggrieved party or parties within 20 calendar days of receipt of such notice.

(c) If the parties fail to adjust the claim within 20 calendar days as specified in paragraph (b) of this section, each party has 10 calendar days to appoint an arbitrator. Immediately upon their appointment, the two arbitrators must agree upon a third arbitrator. If the two arbitrators fail to agree upon a third arbitrator within 10 calendar days of their appointment, they must immediately notify the parties. If the parties cannot agree upon a third arbitrator within five calendar days after receipt of such notice, the Superintendent must appoint the third arbitrator.

(1) All arbitrators must be disinterested persons.

(2) Where both a surface owner and their tenant(s) or surface lessee(s) are injured, the aggrieved parties must join in the appointment of an arbitrator. Where an injury is chargeable to more than one lessee or permittee, all chargeable lessees or permittees must join in the appointment of an arbitrator.

(3) Each claimant and lessee or permittee must pay the fees and expenses for the arbitrator they appoint. The fees and expenses of the third arbitrator must be borne equally by the claimant(s) and lessee(s) or permittee(s).

(d) Immediately following the appointment of the third arbitrator, the arbitrators must meet, hear the evidence and arguments of the parties, and examine the crops, improvements, lands, or other property allegedly damaged. Within 10 calendar days thereafter, the arbitrators must issue a written decision regarding the amount of damages due and serve the decision upon all interested parties. Any two of the arbitrators may render the decision as to the amount of damages due.

(e) Each party has 90 calendar days from the date the arbitrators' decision is served to file an action in a court of competent jurisdiction challenging the decision. If no such action is filed and the arbitration resulted in a decision finding the lessee or permittee liable for surface damages, the lessee or permittee must pay all damages together with interest assessed from the date of the award at the IRS underpayment rate pursuant to 26 U.S.C. 6621(a)(2) within 10 calendar days after expiration of the period for filing an action in court. The IRS underpayment rate is posted quarterly and is available online at *https://www.irs.gov.*

(f) If the claimant is an Indian landowner, the lessee or permittee must submit any surface damages settlement agreement to the Superintendent for approval. The settlement agreement must describe the nature and location of the damages, date(s) of occurrence, settlement amount, and any other pertinent information.

Subpart I—Production and Site Security

General Requirements

§ 226.84 Production obligations.

(a) The Superintendent may order a lessee to promptly drill and produce wells on any lease acreage regardless of whether the lessee has drilled and paid rental if, in their opinion:

(1) A prudent lessee would conduct further development; or

(2) Such drilling is necessary to ensure that the lease is properly and timely developed in accordance with sound economic operating practices.

(b) Failure to develop a lease in compliance with the Superintendent's order is a violation of the terms and conditions of the lease and results in termination of the lease by operation of law as to the acreage the lessee was ordered to develop.

(c) The lessee must put all oil and gas produced from the lease into marketable condition at no cost to the Osage Nation.

(d) Where oil accumulates in a pit, such oil must either be recirculated through the regular treating system and returned to the stock tanks for sale or pumped into a stock tank without treatment and measured for sale in the same manner as from any sales tank under the regulations in this part.

(e) Except in an emergency, no oil may be pumped into a pit without the Superintendent's prior approval. Each such pumping occurrence must be reported to the Superintendent immediately, but not later than the next business day, and the oil promptly recovered in accordance with applicable orders and notices.

§ 226.85 Production reporting.

(a) The lessee must submit certified monthly production reports to ONRR using Form ONRR–4054, Oil and Gas Operations Report, regardless of whether there was production during the reporting period, if the lessee operates a lease or cooperative agreement upon which one or more wells are not permanently plugged and abandoned.

(b) The lessee must submit Form ONRR–4054 for each well every month beginning with the month in which drilling is completed or, if production testing is conducted during drilling operations, beginning with the month in which testing occurs. Such reporting must continue until the lease or cooperative agreement terminates or is cancelled and the Superintendent determines that all wells have been permanently plugged and abandoned.

(c) Reports must be received by 4 p.m. mountain time on or before the 15th day of the second month following the production month.

(d) The lessee must submit Form ONRR–4054 electronically via ONRR's eCommerce Reporting website, *https://onrrreporting.onrr.gov,* unless they qualify for an exception under paragraph (e) of this section. The lessee must enter production data into the system manually or upload data files in American Standard Code for Information Exchange (ASCII) or Comma Separated Values (.csv) file formats that ONRR specifies. Information regarding how to complete and submit Form ONRR–4054 is available at *https://www.onrr.gov/ReportPay/royalty-reporting.htm.*

(e) The lessee may submit Form ONRR–4054 manually if they:

(1) Have never reported to ONRR before. In such instance, they have three months from the date the first production report is due to begin reporting electronically; or

(2) Have a small business, as defined by the Small Business Administration, and do not own a computer.

(f) Production reports submitted manually via U.S. Postal Service must be addressed to: Office of Natural Resources Revenue, P.O. Box 25627, Denver, CO 80225–0627. Production reports submitted manually via courier or overnight delivery service must be addressed to: Office of Natural Resources Revenue, Denver Federal Center, Building 85, Room A–614, 6th Avenue and Kipling Street, Denver, CO 80225.

§ 226.86 Site facility diagrams.

(a) A site facility diagram is required for all permanent facilities. A site facility diagram is not required for temporary measurement facilities used during well testing operations. No format is prescribed for site facility diagrams. The diagram should be formatted to fit on an 8½ x 11-inch sheet of paper, if possible, and must be legible and comprehensible to an individual with an ordinary working knowledge of oil and gas field operations. If more than one page is required, each page must be numbered using the format ''N of X pages.'' The diagram does not need to be to scale. Sample site facility diagrams are available at *https://www.bia.gov/regional-offices/eastern-oklahoma/osage-agency.*

(b) The site facility diagram must:

(1) Clearly identify the name of the lessee, lease(s) the diagram applies to, and facility location. Facility location must include both GPS coordinates and the legal description;

(2) Reflect the position of the production and water recovery equipment, piping for oil, gas, and water, and metering or other measuring systems in relation to each other;

(3) Commencing with the header, identify all equipment including, but not limited to, the header, wellhead, piping, tanks, metering systems located on the site, appropriate valves, and any other equipment used in the handling, conditioning, or disposal of production and water, and must indicate the direction or flow;

(4) Identify the wells flowing into headers by US Well Number;

(5) Indicate which valve(s) must be sealed and in what position during the production phase, sales phase, and during other production activities (*e.g.,* circulating tanks or drawing off water), which may be shown by an attachment, if necessary;

(6) Clearly identify all meters and measurement equipment on the diagram or in an attachment to the diagram; and

(7) Clearly identify the FMP(s) for each measurement facility where the measurement affects calculation of the volume or quality of oil and gas production upon which royalty is owed. Where production from more than one well will flow into the FMP(s), the lessee must list all US Well Numbers associated with each FMP.

(c) For new, permanent facilities that become operational after [effective date of final rule], a site facility diagram must be filed within 60 calendar days after the facilities become operational.

(d) For facilities that are in service on or before [effective date of final rule], a site facility diagram identifying FMPs, as required by paragraph (b)(7) of this section, must be filed by [120 days after effective date of final rule] or such longer period as the Superintendent may authorize.

(e) After a site facility diagram is submitted pursuant to this section, the lessee has an ongoing obligation to amend the diagram within 60 calendar days after any facilities are modified.

§ 226.87 Assignment of facility measurement point (FMP) numbers.

The BIA will assign a unique FMP number to each oil and gas FMP identified on the site facility diagram submitted under § 226.85.

(a) For a new facility in service after [effective date of final rule], the lessee must start using FMP numbers for reporting to ONRR the first production month after the BIA assigns the FMP numbers and every month thereafter.

(b) For an existing facility in service on or before [effective date of final rule], the lessee must start using FMP numbers for reporting to ONRR the third production month after the BIA assigns the FMP numbers and every month thereafter.

§ 226.88 Requirements for production records.

(a) Lessees, purchasers, transporters, and other persons involved in producing, transporting, purchasing, selling, or measuring oil and gas through the point of royalty measurement or point of first sale, whichever is later, must retain all records, including source records, relevant to determining the quality, quantity, disposition, and verification of production attributable to the subject lease. This applies to all records generated during, or for, the period the lessee has an interest in, or conducts operations on, the lease or the period in which a purchaser, transporter, or other persons are involved in transporting, purchasing, or selling production therefrom.

(b) Records that are created after [effective date of final rule] must be legible and include the following:

(1) The FMP, lease, or unit number;

(2) A unique equipment identifier (*e.g.,* a unique tank or meter station number);

(3) The name of the person who created the record; and

(4) The signor's printed name, for any records requiring a signature.

(c) Records under this section must be maintained and preserved for a minimum of six years from the date upon which the relevant transaction was recorded unless the Superintendent or ONRR provides written notice to the lessee that an audit or investigation is being conducted and the records must be maintained for a longer period. If an audit or investigation of the records is being conducted, the lessee must maintain the records until the Superintendent or ONRR issues a written release of such obligation.

(d) Records under this section must be made available to the Superintendent or ONRR for inspection upon request. A reasonable period of time will be provided to produce historical records.

§ 226.89 Easements for access to wells located off-lease.

(a) The Superintendent may grant commercial and non-commercial SWD easements for access to existing wells located off-lease on trust or restricted Indian lands in accordance with the regulations in part 169 of this title.

(b) The grantee must post a performance bond for all SWD easements in accordance with the requirements in subpart G.

(c) The lessee is responsible for all surface damages resulting from use of the easement and must settle such damages as provided in § 226.83.

Waste Prevention

§ 226.90 Prevention of waste.

(a) A lessee must conduct all operations in a manner that prevents the waste of oil and gas and must not use oil and gas in a wasteful manner.

(b) The Superintendent has authority to impose requirements deemed necessary to prevent the waste of oil and gas and promote the maximum ultimate economic recovery thereof, consistent with conservation of the resources.

(c) For purposes of this section, waste includes, but is not limited to, inefficient, excessive, or improper use or dissipation of reservoir energy resulting in a reasonable reduction in the quality of oil and gas that may be produced or the unnecessary or excessive surface loss or destruction of oil and gas without beneficial use.

§ 226.91 Royalty on lost or wasted production.

(a) Royalty is due on all oil and gas avoidably lost or wasted. The Superintendent and ONRR will determine the volume and quality of lost or wasted production. Royalty is not due on oil and gas that is unavoidably lost.

(b) The following qualify as avoidably lost production:

(1) Gas that is vented or flared without the Superintendent's prior approval; and

(2) Produced oil or gas that the Superintendent determines was lost because of the lessee's:

(i) Negligence;

(ii) Failure to take all reasonable measures to prevent or control the loss; or

(iii) Failure to comply with applicable lease and permit terms and conditions, the regulations in this part, or applicable orders and notices.

(c) The following qualify as unavoidably lost production:

(1) Oil or gas that is lost because of line failures, equipment malfunctions, blowouts, fires, or other similar circumstances, except where the Superintendent determines that the loss was avoidable pursuant to paragraph (b)(2) of this section;

(2) Oil or gas that is lost during the following operations, and from the following sources, except where the Superintendent determines that the loss was avoidable pursuant to paragraph (b)(2) of this section:

(i) Well drilling;

(ii) Well completion and related operations;

(iii)Initial production tests, subject to the limitations in § 226.156(a);

(iv) Subsequent well tests, subject to the limitations in § 226.156(b);

(v) Exploratory coalbed methane well dewatering;

(vi) Normal gas vapor losses from a storage tank or other low-pressure vessel, unless the Superintendent determines that recovery of the gas vapors is warranted;

(vii) Well venting during downhole well maintenance or liquids unloading, performed in compliance with § 226.156(c);

(viii) Facility and pipeline maintenance, such as when the lessee must blow-down and depressurize equipment to perform maintenance or repairs; and

(ix) Emergencies, subject to the limitations in § 226.156(d).

(3) Produced gas that is vented or flared with the Superintendent's approval.

Drainage Obligations

§ 226.92 Prevention of drainage.

(a) Where any lease is being drained of oil and gas by wells on an adjacent lease issued at a lower royalty rate, the Superintendent may require the lessee being drained to:

(1) Drill or modify and produce all wells necessary to protect the lease from drainage;

(2) Enter into a cooperative agreement with the lease upon which the draining well is located; or

(3) Pay compensatory royalties for drainage that has occurred and continues to occur.

(b) The Superintendent may, in their discretion, approve alternative, equivalent protective measures outside of those set forth in paragraph (a) of this section.

(c) The lessee must take protective action within a reasonable time after they first knew, or had constructive notice, that drainage may be occurring. For purposes of this section, a lessee is considered to have constructive notice of drainage if they operate or own any interest in the draining lease or well.

(d) If the Superintendent has reason to believe that drainage is occurring, they will notify the lessee in writing. Such notification does not alleviate the lessee's responsibility to take protective action when they first knew, or had constructive notice, that drainage may be occurring, which date may precede the receipt of notice from the Superintendent.

(e) The Superintendent will determine whether a lessee took protective action within a reasonable time on a case-by-case basis taking into consideration the time required to evaluate the characteristics and performance of the draining well; rig availability; well depth; the need for environmental analysis; weather conditions; and other relevant factors.

(f) The lessee is not required to take any of the protective actions listed in paragraph (a) of this section if they can prove, to the Superintendent's satisfaction, that when they first knew, or had constructive notice, of drainage, a sufficient quantity of oil or gas could not be produced from a protective well for a reasonable profit above the cost of drilling, completing, and operating the protective well.

§ 226.93 Compensatory royalty for drainage.

(a) If the Superintendent determines that a lessee was required to take protective action to prevent drainage under § 226.92 and failed to take such action within a reasonable time, the lessee must pay compensatory royalty for the period of the delay.

(b) The Superintendent will assess compensatory royalty beginning on the first calendar day of the month following the earliest reasonable time the lessee should have taken protective action and continuing until:

(1) The lessee drills adequate economic protective wells, and such wells remain in continuous production;

(2) The Superintendent approves a cooperative agreement that covers the mineral resources being drained or alternative protective measures;

(3) The draining well stops producing; or

(4) The lessee relinquishes their interest in the lease through an assignment.

(c) If a lessee assigns their interest in a lease, they are not liable for drainage that occurs after the effective date of the assignment.

(d) An assignee is liable for all drainage obligations that accrue after the effective date of the assignment.

Site Security

§ 226.94 Storage and sales facilities—seals.

(a) All lines entering or leaving any oil storage tank must have valves capable of being effectively sealed during the production and sales phases unless otherwise provided by the regulations in this part. Existing valves may be modified so that they are capable of being effectively sealed. Appropriate valves must be in an operable condition and accurately reflect whether the valve is open or closed.

(1) During the production phase, all appropriate valves that allow unmeasured production to be removed from storage must be effectively sealed in the closed position. During any other phase (*e.g.,* sales, water draining, hot oiling), and prior to taking the top tank gauge measurement, all appropriate vales that allow unmeasured production to enter or leave the sales tank must be effectively sealed in the closed position.

(2) Each unsealed or ineffectively sealed valve is a separate violation.

(b) Valves, or combinations of valves and tanks, that provide access to production before it is measured for sale are considered appropriate valves and are subject to the seal requirements in this part. If there is more than one valve on a line from a tank, the valve closest to the tank must be sealed.

(c) All appropriate valves must be in operable condition and accurately reflect whether the valve is open or closed.

(d) The following are not considered appropriate valves and, therefore, are not subject to the seal requirements in this part:

(1) Valves on production equipment (*e.g.,* dehydrator, gun barrel, or wash tank);

(2) Valves on water tanks, provided that the possibility of access to production in the sales and storage tanks does not exist through a common circulating drain, overflow, or equalizer system;

(3) Valves on tanks that contain what the Superintendent determines to be slop or waste oil;

(4) Sample cock valves used on piping or tanks with a Nominal Pipe Size of one inch or less in diameter;

(5) Fill-line valves during shipment when a single tank with a nominal capacity of 500 bbl or less is used for collecting marginal production of oil produced from a single well (*i.e.,* production that is less than three bbl per day). All other seal requirements apply;

(6) Gas line valves used on piping with a Nominal Pipe Size of one inch or less used as tank bottom ''roll'' lines, provided that there is no access to the contents of the storage tank and the roll lines cannot be used as equalizer lines;

(7) Valves on tank heating systems that use a fluid other than the contents of the storage tank (*i.e.,* steam, water, glycol);

(8) Valves used on piping with a Nominal Pipe Size of one inch or less, connected directly to the pump body or used on pump bleed off lines;

(9) Tank vent-line valves; and

(10) Sales, equalizer, or fill-line valves on systems where production may be removed only through approved oil metering systems (*e.g.,* LACT or CMS). Any valve that allows access for removal of oil before it is measured through the metering system must be effectively sealed.

(e) Tampering with any appropriate valve is prohibited.

§ 226.95 Oil measurement system components—seals.

(a) Components used for determining the quality or quantity of oil must be effectively sealed to indicate tampering. Such components include, but are not limited to, the following components of LACT meters and CMSs:

(1) The sampler volume control;

(2) All valves on lines entering or leaving the sample container, excluding the safety pop-off valve, if so equipped. Each valve must be sealed in the open or closed position, as appropriate;

(3) The mechanical counter head (totalizer) and meter head;

(4) The stand-alone temperature averager monitor;

(5) The non-automatic adjusting, fixed back-pressure valve pressure adjustment downstream of the meter;

(6) Any drain valves larger than one inch in nominal diameter; and

(7) The right-angle drive.

(b) Each missing or ineffectively sealed component is a separate violation.

§ 226.96 Removing production from tanks for sale and transportation by truck.

(a) When a single truckload constitutes a completed sale, the driver must possess the documentation required in § 226.114.

(b) When multiple trucks are involved in a sale and the oil measurement method is based on the difference between the opening and closing gauges, the driver of the last truck must possess the documentation required in § 226.114. All other drivers involved in the sale must possess a trip log or manifest.

(c) After the seals have been broken, the purchaser or transporter is responsible for the entire contents of the tank until it is resealed. When a single truck is involved in a sale with multiple truckloads, the purchaser or transporter must seal the tank in between each individual truckload.

§ 226.97 Documentation required for transportation of oil and gas.

(a) Any person engaged in transporting by motor vehicle any oil produced from or allocated to any lease, must carry on their person, in their vehicle, or have in their immediate control, documentation showing the amount, origin, and intended first purchaser of the oil.

(b) Any person engaged in transporting any oil or gas produced from or allocated to any lease by pipeline, must maintain documentation showing the amount, origin, and intended first purchaser of the oil or gas.

(c) Any properly identified authorized representative of the Superintendent may stop and inspect any motor vehicle on a lease if they have probable cause to believe the vehicle is carrying oil produced from or allocated to the lease, to determine whether the driver possesses proper documentation for the load of oil.

(d) Any appropriate law enforcement officer or properly identified authorized representative of the Superintendent accompanied by an appropriate law enforcement officer, may stop and inspect any motor vehicle that is off lease, if there is probable cause to believe the vehicle is carrying oil produced from or allocated to a lease, to determine whether the driver possesses proper documentation for the load of oil.

§ 226.98 Water draining operations.

When water is drained from a production storage tank, the lessee, purchaser, or transporter must document the following information:

(a) The lease number;

(b) The tank location using both GPS coordinates and legal description;

(c) The unique tank number and nominal capacity;

(d) The date of the opening gauge;

(e) The opening gauge (gauged manually or automatically), TOV, and free water measurements, all to the nearest ½ inch;

(f) The unique identifying number of each seal removed;

(g) The closing gauge (gauged manually or automatically) and TOV measurement to the nearest ½ inch; and

(h) The unique identifying number of each seal installed.

§ 226.99 Hot oiling, clean-up, and completion operations.

(a) During hot oil, clean-up, completion operations, or any other situation where the lessee removes oil from storage, temporarily uses it for operational purposes, and then returns it to storage, they must document the following information:

(1) The lease number;

(2) The tank location using both GPS coordinates and legal description;

(3) The unique tank number and nominal capacity;

(4) The date of the opening gauge;

(5) The opening gauge measurement (gauged manually or automatically) to the nearest ½ inch;

(6) The unique identifying number of each seal removed;

(7) The closing gauge measurement (gauged manually or automatically) to the nearest ½ inch;

(8) The unique identifying number of each seal installed;

(9) How the oil was used; and

(10) Where the oil was used (*e.g.,* well or facility name and number).

(b) During hot oiling, line flushing, or completion operations of any other kind where the lessee removes production from storage for use on a different lease, the production is considered sold and must be measured in accordance with the requirements in the regulations in this part and reported to ONRR for the period covering the production in question.

§ 226.100 Seal records.

For each seal, the lessee must maintain a record that includes the:

(a) Unique identifying number of each seal and the valve or meter component on which the seal is, or was, used;

(b) Date of installation or removal of each seal;

(c) Position in which the valve was sealed (*e.g.,* open or closed); and

(d) Reason the seal was removed.

§ 226.101 Requirements for off-lease measurement of production.

(a) The lessee must submit a request, in writing, for off-lease measurement of production and obtain the Superintendent's approval thereof. The request must include the following information:

(1) The lessee's name;

(2) The lease number for which the lessee is requesting off-lease measurement;

(3) The US Well Number(s) and GPS coordinates for each well included in the off-lease measurement proposal; and

(4) The lease number and legal description for the existing or proposed off-lease FMP.

(b) Off-lease measurement of production must occur at an identified FMP unless the Superintendent authorizes otherwise.

§ 226.102 Report of spills, theft, mishandling of production, accidents, or fires.

(a) Lessees must report the following to the Superintendent and surface owner(s) immediately upon discovery, but not later than the calendar day following discovery:

(1) All spills or releases of oil, gas, produced water, toxic liquids, deleterious substances, or waste materials;

(2) Theft of equipment or production;

(3) Blowouts;

(4) Fires;

(5) Mishandling of production; and

(6) Accidents on the lease that resulted in the loss of production or damage to measurement equipment.

(b) In addition to providing emergency notification by phone or in person, the lessee must also send written notice of the incidents identified in paragraphs (a)(1) through (4) of this section to surface owner(s) by certified mail—return receipt requested.

(c) The lessee must submit a Spill and Remediation Report for all spills and releases, and a written report of all other incidents, to the Superintendent within five business days of any incident identified in paragraph (a) of this section, together with a proposed contingency or remediation plan that describes the procedures being implemented to restore resource values and protect life, property, and the environment.

(d) The lessee must exercise due diligence in taking necessary measures to control and remove pollutants and extinguish fires.

(e) Compliance with the requirements set forth in the regulations in this part does not relieve the lessee of the obligation to comply with all other applicable laws and regulations.

Subpart J—Oil Measurement

§ 226.103 General requirements.

(a) Oil must be measured on the lease or unit area from which it is produced unless approval for off-lease measurement of production is obtained in accordance with § 226.101.

(b) All bypasses of meters are prohibited.

(c) Tampering with any measurement device, component of a measurement device, or measurement process is prohibited.

(d) Violation of the prohibitions set forth in paragraphs (b) and (c) of this section will result in assessment of the maximum penalty available under § 226.162(c).

§ 226.104 Timeframes for compliance.

(a) All equipment and procedures used to measure the volume of oil for royalty purposes after [effective date of final rule] must comply with the requirements in this subpart.

(b) All equipment and procedures used to measure the volume of oil for royalty purposes installed or in-use on leases approved prior to [effective date of final rule] must comply with the requirements in this subpart by [one year from effective date of final rule]. Prior to that date, the equipment and procedures used to measure oil for royalty purposes must continue to comply with § 226.38, as it appears in 25 CFR part 226 (April 1, 2017, edition) and any applicable orders or notices.

§ 226.105 [Reserved]

§ 226.106 Specific measurement performance requirements.

(a) *Volume measurement uncertainty levels.* (1) The FMP must achieve the following volume measurement uncertainty levels, calculated in accordance with the statistical methodologies set forth in API 13.3 and the quadrature sum method set forth in Subsection 12.3 of API 14.3.1 (both incorporated by reference, see § 226.0):

TABLE 1 TO PARAGRAPH (a)(1)—VOLUME MEASUREMENT UNCERTAINTY LEVELS

If the averaging period volume is:	The overall volume measurement uncertainty level must be within:
1. Greater than or equal to 30,000 bbl/month.	+/− 0.50 percent.
2. Less than 30,000 bbl/month.	+/− 1.50 percent.

(2) The Superintendent may grant an exception to the uncertainty levels in paragraph (a) of this section only upon the lessee's showing that meeting the required uncertainty level would involve extraordinary cost or unacceptable adverse environmental effects.

(b) *Bias.* The measurement equipment used for volume determinations must achieve measurement without statistically significant bias.

(c) *Verifiability.* All FMP equipment must be susceptible to the BIA's independent verification of the accuracy and validity of all inputs, factors, and equations used to determine quality or quantity. Verifiability includes the ability to independently recalculate the volume and quality of oil based on source records.

§ 226.107 Tank gauging—general requirements.

(a) Oil measurement by tank gauging must be performed using the procedures set forth in § 226.108 and accurately compute the total net standard volume of oil withdrawn from a properly calibrated sales tank.

(b) Each tank used for oil storage must comply with the recommended practices in Subsection 4 of API RP 12R1 (incorporated by reference, see § 226.0) and must be connected, maintained, and operated in compliance with §§ 226.94, 226.98, and 226.99.

(c) All oil storage tanks must be clearly identified and have a unique number the lessee generated stenciled on the tank and maintained in a legible condition.

(d) Each oil storage tank that has a tank gauging system and is associated with an FMP must be set and maintained on a level plane.

(e) Each oil storage tank that has a tank gauging system and is associated with an FMP must be gauged using a gauging reference point located at 180 degrees (6:00 o'clock) when the individual performing the gauging is facing the tank hatch unless the Superintendent approves an alternative method.

(f) The lessee must accurately calibrate each oil storage tank that has a tank gauging system and is associated with an FMP using either API 2.2A, API 2.2B, or API 2.2C and API RP 2556 (all incorporated by reference, see § 226.0) and:

(1) Determine sales tank capacities by tank calibration using actual tank measurements, with unit volume in bbl and incremental height measurements that match the gauging increment specified in § 226.108(b)(5)(i)(d);

(2) Recalibrate the sales tank if there is a change in purchaser, the tank is relocated or repaired, or the capacity of the tank changes due to denting, damage, installation, removal of interior components, or other alterations; and

(3) Submit sales tank tables to the Superintendent within 45 calendar days after calibration or recalculation of the tables.

§ 226.108 Tank gauging—procedures.

(a) The lessee may use manual or automatic tank gauging to determine the quality and quantity of oil measured under field conditions at an FMP. The Superintendent's prior approval is required for all automatic tank gauging. Requests for authorization to use automatic tank gauging must be submitted to the Superintendent in writing and include the make and model of the automatic tank gauge (ATG) the lessee proposes to use.

(b) The lessee must comply with the following procedures to determine the quality and quantity of oil measured:

(1) *Isolate tank.* Isolate the tank for at least 30 minutes to allow the contents to settle before conducting tank gauging operations. Tank isolating valves must be closed and sealed in accordance with § 226.94.

(2) *Determine opening oil temperature.* Determine the temperature of oil contained in the sales tank in accordance with API 7.1 or API 7.2 (both incorporated by reference, see § 226.0) and the following requirements:

(i) A single temperature measurement at the middle of the liquid may be used for tanks with less than 5,000 bbls nominal capacity;

(ii) Glass thermometers must be clean, free of fluid separation, and have a minimum graduation of 1.0 °F and an accuracy of +/− 0.5 °F; and

(iii) Electronic thermometers must have a minimum graduation of 1.0 °F and an accuracy of +/− 0.5 °F.

(3) *Take oil samples.* The lessee must conduct sampling operations prior to taking the opening gauge unless automatic sampling methods are used. Sampling of oil removed from an FMP tank must yield a representative sample of the oil and its physical properties and comply with the requirements in API 8.1 (incorporated by reference, see § 226.0).

(4) *Determine observed oil gravity.* The lessee must conduct tests for oil gravity in accordance with API 9.1, API 9.2, or API 9.3 (all incorporated by reference, see § 226.0) and the following requirements:

(i) The hydrometer or thermohydrometer must be clean with a clear, legible oil gravity scale and no loose shot weights and must be calibrated for an oil gravity range that includes the observed gravity of the oil sample being tested;

(ii) The lessee must allow the temperature to stabilize for a minimum of five minutes prior to reading the hydrometer or thermohydrometer; and

(iii) The lessee must read and record the observed API oil gravity to the nearest 0.1 degree and the temperature to the nearest 1.0 °F.

(5) *Measure opening tank fluid level.* The lessee must take and record the opening gauge only after samples have been taken.

(i) The lessee must conduct manual gauging in accordance with API 3.1A and API 18.1 (both incorporated by reference, see § 226.0) subject to the following exceptions, additions, and clarifications:

(A) The proper innage-gauging bob for the measurement method must be used;

(B) A gauging tape must be used. The tape must be made of steel or corrosion-resistant material with graduation clearly legible and must not be kinked or spliced;

(C) A suitable product-indicating paste must be used on the gauging tape to facilitate the reading. The use of chalk or talcum powder is prohibited; and

(D) The lessee must obtain two consecutive gauging measurements that are within ¼ inch of each other for any tank regardless of size.

(ii) The lessee must conduct automatic tank gauging in accordance with API 3.1B, and API 3.6 (both incorporated by reference, see § 226.0) and the following requirements:

(A) The ATG must be inspected, and its accuracy verified to within +/− ¼ inch, in accordance with the procedures in Subsection 9 of API 3.1B (incorporated by reference, see § 226.0) prior to sales and upon the Superintendent's request. If the ATG is found to be out of the manufacturer's tolerance, the lessee will be required to calibrate the ATG prior to sales; and

(B) The lessee must make a detailed log of ATG field verifications available to the Superintendent upon request.

(6) *Determine S&W content.* Determine the S&W content of the oil in the sales tanks in accordance with API 10.4 (incorporated by reference, see § 226.0) using the oil samples obtained pursuant to paragraph (d) of this section.

(7) *Transfer oil.* Break the tank load valve seal and transfer the oil to the tanker truck. After the transfer is complete, close and seal the tank valve in accordance with §§ 226.94 and 226.96.

(8) *Determine closing oil temperature.* Determine the closing oil temperature using the procedures set forth in paragraph (b)(2) of this section.

(9) *Take closing tank gauge.* Take the closing tank gauge using the procedures set forth in paragraph (b)(5) of this section.

(10) *Complete run ticket.* Complete the run ticket in accordance with § 226.114.

§ 226.109 LACT system—general requirements.

(a) LACT systems must meet the construction and operation requirements and minimum standards set forth in this section and §§ 226.103 and 226.110.

(b) LACT systems must be proven as set forth in § 226.113.

(c) Run tickets must be completed as set forth in § 226.114.

(d) All components of LACT systems must be accessible for inspection.

(e) The lessee must notify the Superintendent, in writing, of any LACT system failure or equipment malfunction that may have resulted in measurement error within 15 calendar days of discovering the failure.

(f) Any tests conducted on oil samples extracted from LACT system samplers for determination of S&W content and observed oil gravity must meet the requirements and minimum standards set forth in § 226.108(b)(2), (4), and (6).

(g) The average temperature for the run ticket must be calculated for the measurement period covered by the run ticket and must be the temperature used to calculate the CTL correction factor using API 11.1 (incorporated by reference, see § 226.0).

§ 226.110 LACT system—components and operating requirements.

(a) Each LACT system must include all equipment listed in API 6.1 (incorporated by reference, see § 226.0), subject to the following exceptions:

(1) The LACT meter must be a positive displacement or Coriolis meter;

(2) An electronic temperature averaging device must be installed; and

(3) Meter back-pressure must be applied by a back-pressure valve or other controllable means of applying back-pressure. Back-pressure may be maintained by an automatic-adjusting back-pressure control to adjust for changing flow conditions. Back-pressure control must maintain a pressure that is above the bubble point of the liquid to prevent the formation of vapor, ensuring single-phase flow.

(b) All LACT system components must be operated in accordance with API 6.1 (incorporated by reference, see § 226.0) and the following requirements:

(1) Sampling and mixing must be conducted in accordance with API 8.2 and API 8.3 (both incorporated by reference, see § 226.0), and the sample exactor probe must be inserted in the center half of the flowing stream, horizontally oriented, and have external markings that show the orientation of the probe in relation to the direction of flow.

(2) All tests conducted on oil samples extracted from LACT system samplers for determination of oil gravity must be conducted in accordance with API 9.1, API 9.2, or API 9.3 (all incorporated by reference, see § 226.0). All tests for the determination of S&W content must be conducted in accordance with API 10.4 (incorporated by reference, see § 226.0).

(3) The composite sample container must be emptied and cleaned upon completion of the sample withdrawal.

(4) The positive displacement or Coriolis meter must be equipped with a non-resettable totalizer. The non-resettable totalizer display may reside in an electronic flow computer. The meter must include or allow for the attachment of a device that generates at least 8,400 pulses per bbl of registered volume.

(5) The pressure-indicating device must be located downstream of the meter, but upstream of the first valve of the prover connections. The pressure-indicating device must be capable of providing pressure data to calculate the CPL correction factor.

(6) The electronic temperature averaging device may be a stand-alone device or a function of a flow computer and must be installed, operated, and maintained as follows:

(i) The temperature thermowell and transducer must be installed as set forth in Subsections 6.3 and 7.2 of API 7.4 (incorporated by reference, see § 226.0);

(ii) The electronic temperature averaging device must be volume-weighted and take a temperature reading as set forth in Subsection 9.2.8 of API 21.2 (incorporated by reference, see § 226.0);

(iii) The average temperature for the run ticket must be calculated using the volumetric averaging method set forth in Subsection 9.2.13.2a of API 21.2 (incorporated by reference, see § 226.0);

(iv) The temperature averaging device must have a reference accuracy of +/−0.5 °F or better and a minimum graduation of 0.1 °F.

(v) The temperature averaging device must include a display of the instantaneous temperature and average temperature calculated since the run ticket was opened. The display may be a function of an electronic flow computer; and

(vi) The average temperature calculated since the run ticket was opened must be used to calculate the CTL correction factor.

(7) The net standard volume must be calculated at the close of each run ticket in accordance with the guidelines set forth in API 11.1 and API 12.2.2 (both incorporated by reference, see § 226.0).

§ 226.111 Coriolis measurement systems (CMS)—general requirements and components.

This section applies to Coriolis measurement applications that are independent of LACT systems.

(a) A CMS must meet the requirements and minimum standards set forth in this section and §§ 226.106 and 226.112.

(b) A CMS must be proven as set forth in § 226.113.

(c) Run tickets must be completed as set forth in § 226.114.

(d) A CMS at an FMP must be installed with the components listed in API 5.6 (incorporated by reference, see § 226.0) and in accordance with the following requirements:

(1) The pressure transducer must meet the requirements set forth in § 226.110(b)(5);

(2) The temperature determination must meet the requirements set forth in § 226.110(b)(6);

(3) The sampling system must meet the requirements set forth in § 226.110(b)(1) through (3) if nonzero S&W content is to be used in determining net oil volume. If no sampling system is used, or the sampling system does not meet the requirements in § 226.110(b)(1) through (3), the S&W content must be reported as zero.

(4) Sufficient back-pressure must be applied to ensure single-phase flow through the meter.

(e) The API oil gravity reported for the run ticket period must be:

(1) Determined from a composite sample taken in accordance with § 226.110(b)(1) through (3); or

(2) Calculated from the average density as measured by the CMS over the run ticket period in accordance with

Subsection 9.2.13.2a of API 21.2 (incorporated by reference, see § 226.0). Density must be corrected to base temperature and pressure in accordance with API 11.1 (incorporated by reference, see § 226.0).

§ 226.112 Coriolis meter—operating requirements.

(a) *Minimum electronic pulse level.* The Coriolis meter must register the volume of oil passing through the meter as determined by a system that constantly emits electronic pulse signals representing the indicated volume measured. The pulse per unit volume must be set at a minimum of 8,400 pulses per bbl.

(b) *Meter specifications.* The Coriolis meter specifications must identify the make and model of the meter they apply to and include the following:

(1) The reference accuracy for both mass flow rate and density, stated in percent of reading, percent of full scale, or units of measure;

(2) The effect of changes in temperature and pressure on both mass flow and fluid density readings, and the effect of flow rate on density readings, stated in percent of reading, percent of full scale, or units of measure over a stated amount of change in temperature, pressure, or flow rate (*e.g.,* +/−0.1 percent of reading per 20 psi);

(3) The stability of the zero reading for volumetric flow rate, stated in percent of reading, percent of full scale, or units of measure;

(4) The design limits for flow rate and pressure; and

(5) The pressure drop through the meter as a function of flow rate and fluid viscosity.

(c) *Submission of meter specifications.* The lessee must submit Coriolis meter specifications to the Superintendent upon request.

(d) *Non-resettable totalizer.* The Coriolis meter must have a non-resettable internal totalizer for indicated volume.

(e) *Verification of meter zero-value using the manufacturer's specifications.* If the indicated flow rate is within the manufacturer's specifications for zero stability, no adjustments are required. If the indicated flow rate is outside such specifications, the meter's zero reading must be adjusted. After the meter's zero has been adjusted, the meter must be proven as set forth in § 226.113. A copy of the zero-value verification procedure must be provided to the Superintendent upon request.

(f) *Required on-site information.*

(1) The Coriolis meter display must be readable without using data collection units, laptop computers, or any special equipment and must be on-site and accessible to the Superintendent.

(2) The following values and corresponding units of measurement must be displayed for each Coriolis meter:

(i) The instantaneous display of liquid density (pounds/bbl, pounds/gal, or degrees API);

(ii) The instantaneous indicated volumetric flow rate through the meter (bbl/day);

(iii) The meter factor;

(iv) The instantaneous pressure (psi);

(v) The instantaneous temperature (°F);

(vi) The cumulative gross standard volume through the meter (non-resettable totalizer) (bbl); and

(vii) The previous day's gross standard volume through the meter (bbl).

(3) The following information must be correct, maintained in legible condition, and accessible to the Superintendent at the FMP without the use of data collection equipment, laptop computers, or any other special equipment:

(i) The make, model, and size of each sensor; and

(ii) The make, model, range, and calibrated span of the pressure and temperature transducer used to determine gross standard volume.

(4) The lessee must maintain a log of all meter factors, zero verifications, and zero adjustments. For zero adjustments, the log must include the zero value after adjustment. The log must be made available to the Superintendent upon request.

(g) *Audit trail requirements.* The information identified in paragraphs (g)(1) through (4) of this section must be recorded and maintained by the lessee for six years from the date it was generated unless the Superintendent provides written notice to the lessee that an audit or investigation is being conducted and the records must be maintained for a longer period. If an audit or investigation of the records is being conducted, the lessee must maintain the records until the Superintendent issues a written release of such obligation. Audit trail requirements must follow Subsection 10 of API 21.2 (incorporated by reference, see § 226.0). All data and records must be provided to the Superintendent upon request.

(1) *Quantity transaction record (QTR).* The QTR must comply with the requirements for run tickets set forth in § 226.114.

(2) *Configuration log.* The configuration log must comply with the requirements set forth in Subsection 10.2 of API 21.2 (incorporated by reference, see § 226.0), and identify all constant flow parameters used in generating the QTR.

(3) *Event log.* The event log must comply with the requirements set forth in Subsection 10.6 of API 21.2 (incorporated by reference, see § 226.0).

(4) *Alarm log.* The alarm log must record the type and duration of density deviations from acceptable parameters and instances in which the flow rate exceeded the manufacturer's maximum recommended flow rate or was below the manufacturer's minimum recommended flow rate.

(h) *Data protection.* To ensure that audit trail requirements under paragraph (g) of this section are met, each Coriolis meter must have a backup power supply installed and maintained in operable condition or a non-volatile memory capable of retaining all data in the unit's memory.

§ 226.113 Meter proving requirements.

(a) This section specifies the minimum requirements for conducting volumetric meter proving for all FMP meters.

(b) *Meter prover.* The only acceptable provers are positive displacement master meters, Coriolis master meters, and displacement provers. The lessee must ensure that the meter prover used to determine the meter factor has a valid certificate of calibration, identifying the prover by serial number, on site and available for the Superintendent's review. The certificate must show that the prover was calibrated as follows:

(1) Master meters must have a meter factor within 0.9900 to 1.0100 determined by a minimum of five consecutive prover runs within 0.0005 (0.05 percent repeatability) as set forth in Subsection 6.5, Table 2 of API 4.5 (incorporated by reference, see § 226.0). The master meter must not be mechanically compensated for oil gravity or temperature; its readout must indicate units of volume without corrections.

(2) The meter factor must be documented on the calibration certificate and must be calibrated at least once every 12 months. New master meters must be calibrated immediately and recalibrated three months thereafter. Master meters that have undergone mechanical repairs, alterations, or changes that affect the calibration must be calibrated immediately upon the completion of this work and recalibrated three months thereafter in accordance with Annex B of API 4.8 (incorporated by reference, see § 226.0).

(3) Displacement provers must meet the requirements set forth in API 4.2

and be calibrated using the water-draw method set forth in API 4.9.2 at the calibration frequencies specified in Subsection 10.1(b) of API 4.8 (all incorporated by reference, see § 226.0).

(4) The base prover volume of a displacement prover must be calculated in accordance with API 12.2.4 (incorporated by reference, see § 226.0).

(5) Displacement provers must be sized to obtain a displacer velocity through the prover that is within the appropriate range during proving in accordance with Subsections 4.3.4.1 and 4.3.4.2 of API 4.2 (incorporated by reference, see § 226.0).

(6) Fluid velocity is calculated using Subsection 4.3.4.3, Equation 12 of API 4.2 (incorporated by reference, see § 226.0).

(c) *Meter proving runs.* Meter proving must comply with the applicable section(s) of API 4.1 (incorporated by reference, see § 226.0) and the following requirements:

(1) Meter proving must be performed under normal operating conditions. The normal operating conditions will be established by the flow rate, fluid pressure, fluid temperature, and fluid gravity at the time of proving. These established conditions will be in effect until the next proving.

(i) The oil flow rate through the LACT or CMS during proving must be within 10 percent of the normal flow rate;

(ii) The pressure as measured by the LACT or CMS during proving must be within 10 percent of the normal flow rate;

(iii) The temperature as measured by the LACT or CMS during the proving must be within 10 °F of the normal operating temperature;

(iv) The gravity of the oil during proving must be within 5° API of the normal oil gravity; and

(v) If the normal flow rate, pressure, temperature, or oil gravity vary by more than the limits defined in paragraphs (c)(1) through (4) of this section, meter provings must be conducted at the upper, lower, and midpoint limits of normal operating conditions.

(2) If each proving run is not of sufficient volume to generate at least 10,000 pulses from the positive displacement meter or the Coriolis meter as specified in Subsection 4.3.2.1 of API 4.2, then pulse interpolation must be used in accordance with API 4.6 (both incorporated by reference, see § 226.0).

(3) Proving runs must be made until the calculated meter factor or meter-generated pulses from five consecutive runs match within a tolerance of 0.0005 (0.05 percent) between the highest and lowest value in accordance with Subsection 9 of API 12.2.3 (incorporated by reference, see § 226.0).

(4) The new meter factor is the arithmetic average of the meter-generated pulses or intermediate meter factors calculated from the five consecutive runs in accordance with Subsection 9 of API 12.2.3 (incorporated by reference, see § 226.0).

(5) Meter factor computations must follow the sequence set forth in Subsection 12 of API 12.2.3 (incorporated by reference, see § 226.0).

(6) If multiple meter factors are determined over a range of normal operating conditions, then:

(i) If all the meter factors determined over a range of conditions fall within 0.0020 of each other, a single meter factor may be calculated for that range as the arithmetic average of all the meter factors within that range. The full range of normal operating conditions may be divided into segments such that all the meter factors within each segment fall within a range of 0.0020. In such case, a single meter factor for each segment may be calculated as the arithmetic average of the meter factors within that segment; or

(ii) The metering system may apply a dynamic meter factor derived (using linear interpolation, polynomial fit, etc.) from the series of meter factors determined over the range of normal operating conditions, so long as no two neighboring meter factors differ by more than 0.0020.

(7) The meter factor must be at least 0.9900 and no more than 1.0100.

(8) The initial meter factor for a new or repaired meter must be at least 0.9950 and no more than 1.0050.

(9) For positive displacement meters, the back-pressure valve may be adjusted after proving only within the normal operating fluid flow rate and fluid pressure as described in paragraph (c)(1) of this section. If the back-pressure valve is adjusted after proving, the lessee must document the as-left fluid flow rate and fluid pressure on the proving report.

(10) If a composite meter factor is calculated, the CPL value must be calculated from the pressure setting of the back-pressure valve or the normal operating pressure at the meter. Composite meter factors must not be used with a Coriolis meter.

(d) *Minimum proving frequency.* The lessee must prove all FMP meters every three months (quarterly) or each time the registered volume flowing through the meter, as measured on the non-resettable totalizer from the last proving, increases by 75,000 bbls, whichever occurs first, but not more frequently than monthly.

(e) *Events triggering proving.* The lessee must prove all FMP meters before the removal or sale of production after any of the following events occur:

(1) Initial meter installation;

(2) Meter zeroing (Coriolis meter);

(3) Modification of mounting conditions;

(4) A change in fluid temperature that exceeds the transducer's calibrated span;

(5) A change in the flow rate, pressure, temperature, or gravity that exceeds the normal operating conditions as set forth in paragraph (c)(1) of this section;

(6) The mechanical or electrical components of the meter are changed, repaired, or removed;

(7) Internal calibration factors are changed or reprogrammed; or

(8) The Superintendent requests proving.

(f) *Excessive meter factor deviation.* If the difference between meter factors established in two successive provings exceeds +/−0.0025, the meter must be immediately removed from service, checked for damage or wear, adjusted or repaired, and reproved before being returned to service.

(1) The arithmetic average of the two successive meter factors must be applied to the production measured through the meter between the date of the previous meter proving and the date of the most recent meter proving.

(2) The proving report must clearly show the most recent meter factor and describe all subsequent adjustments or repairs.

(g) *Verification of the temperature transducer.* As part of each required meter proving and upon replacement, the temperature averager for a LACT system and temperature transducer used in conjunction with a CMS must be verified against a known standard in accordance with the following requirements:

(1) The temperature averager or temperature transducer must be compared with a test thermometer traceable to NIST and having a stated accuracy of +/−0.25° or better; and

(2) The temperature reading displayed on the temperature averager or temperature transducer must be compared with the reading of the test thermometer using one of the following methods:

(i) The test thermometer must be placed in a test thermometer well located not more than 12 inches from the probe of the temperature averager or temperature transducer; or

(ii) Both the test thermometer and probe of the temperature averager or temperature transducer must be placed in an insulated water bath. The water bath temperature must be within 20 °F of the normal flowing temperature of the oil.

(3) The displayed reading of instantaneous temperature from the temperature averager or temperature transducer must be compared with the reading from the test thermometer. If the readings differ by more than 0.5 °F, the difference must be noted on the meter proving report and the temperature average or temperature transducer must be:

(i) Adjusted to match the reading of the test thermometer; or

(ii) Recalibrated, repaired, or replaced.

(h) *Verification of the pressure transducer (if applicable).* As part of each required meter proving and upon replacement, the pressure transducer must be compared with a test pressure device (dead weight or pressure gauge) traceable to NIST and having a stated maximum uncertainty of no more than one-half of the accuracy required from the transducer being verified.

(1) The pressure reading displayed on the pressure transducer must be compared with the reading of the test pressure device.

(2) The pressure transducer must be tested at the following three points:

(i) Zero (atmospheric pressure);

(ii) 100 percent of the calibrated span of the pressure transducer; and

(iii) A point that represents the normal flowing pressure through the Coriolis meter.

(3) If the pressure applied by the test pressure device and the pressure displayed on the pressure transducer vary by more than the required accuracy of the pressure transducer, the pressure transducer must be adjusted to read within the stated accuracy of the test pressure device.

(i) *Density verification (if applicable).* If the API gravity of oil is determined from the average density measured by the Coriolis meter (rather than from a composite sample), then during each proving of the Coriolis meter, the instantaneous flowing density determined by the Coriolis meter must be verified by comparing it with an independent density measurement as set forth in Subsection 9.1.2.1 of API 5.6 (incorporated by reference, see § 226.0). The difference between the indicated density determined from the Coriolis meter and the independently determined density must be within the density reference accuracy specification of the Coriolis meter. Sampling must be performed in accordance with API 8.1, API 8.2, or API 8.3, as appropriate, (all incorporated by reference, see § 226.0).

(j) *Reporting requirements for meter proving.* The lessee must report all meter proving and volume adjustments following any LACT system or CMS malfunction, including excessive meter-factor deviation, to the Superintendent within 14 calendar days after proving. Meter proving reports may use the forms in Subsection 13 of API 12.2.3 or Appendix C of API 5.6 (see § 226.0 for availability information) or any other format containing the same information as the API forms, provided that the calculation of meter factors maintains the proper calculation sequence and rounding.

(k) *Edits and adjustments to reported volume.* (1) If there are measurement errors stemming from an equipment malfunction that results in discrepancies to the calculated volume, the lessee must estimate the volume reported during the period in which the error occurred.

(2) All edits made to the data before submission of the report to ONRR must be documented and include verifiable justifications of the edits made. Such documentation must be made available to the Superintendent and ONRR upon request.

(3) All values on QTRs that have been changed or edited must be clearly identified and cross-referenced to the justification required in paragraph (k)(2) of this section.

(4) The volumes reported to ONRR must be corrected beginning with the date that the inaccuracy occurred. If the date is unknown, the volumes must be corrected beginning with the production month that includes the date that is halfway between the date of the previous and most recent verifications.

§ 226.114 Run tickets.

(a) *Tank gauging.* After oil is measured by tank gauging, the lessee, purchaser, or transporter, as appropriate, must complete a uniquely numbered run ticket containing the following information:

(1) The lessee's name;

(2) The lease number;

(3) The name of the individual that performed the tank gauging;

(4) The unique tank number and nominal tank capacity;

(5) The opening and closing dates and times;

(6) The open and closing gauges and observed temperatures in °F;

(7) The observed volume for opening and closing gauge using tank-specific calibration charts (see § 226.107(f));

(8) The total net standard volume removed from the tank following API 11.1 (incorporated by reference, see § 226.0);

(9) The observed API oil gravity and temperature in °F;

(10) The API oil gravity at 60 °F, following API 11.1 (incorporated by reference, see § 226.0);

(11) The S&W content percentage; and

(12) The unique numbering of each seal removed and installed.

(b) *LACT system and CMS.* Unless the lessee is using a flow computer, at the beginning of every month, before conducting proving operations on a LACT system, the lessee, purchaser, or transporter, as appropriate, must complete a uniquely numbered run ticket containing the following information:

(1) The lessee's name;

(2) The name of the purchaser's representative;

(3) The lease number;

(4) The unique meter ID number;

(5) The opening and closing dates and times;

(6) The opening and closing totalizer readings of the indicated volume;

(7) The meter factor, indicating whether it is a composite meter factor;

(8) The total gross standard volume removed through the LACT system or CMS;

(9) The API oil gravity;

(i) For API oil gravity determined from a composite sample, the observed API oil gravity and temperature must be indicated in °F and the API oil gravity must be indicated at 60 °F;

(ii) For API oil gravity determined from average density (CMS only), the CMS must determine the average uncorrected density;

(10) The average temperature for the measurement period in °F;

(11) The average flowing pressure for the measurement period in psia;

(12) The S&W content percent; and

(13) The unique number of each seal removed and installed.

(c) Any accumulators used in the determination of average pressure, average temperature, and average density for the measurement period must be reset to zero whenever a new run ticket is opened.

(d) Run tickets must be submitted to the Superintendent on or before the last calendar day of the month following the production month.

§ 226.115 Oil measurement by alternate methods.

Any method of oil measurement at an FMP, other than tank gauging, LACT system, or CMS, requires the Superintendent's prior approval.

§ 226.116 Determination of oil volumes by methods other than measurement.

(a) When production cannot be measured due to a spill or leak, the amount of production will be determined using the method the Superintendent requires. This category of production includes, but is not limited to, oil classified as slop or waste oil.

(b) No oil may be classified or disposed of as waste oil unless the lessee demonstrates to the Superintendent's satisfaction that it is not economically feasible to put such oil into marketable condition.

(c) The lessee must not sell or otherwise dispose of slop oil without prior approval from the Superintendent. The sale or disposal of slop oil must be reported to ONRR in accordance with the requirements set forth in §§ 226.45 and 226.87.

Subpart K—Gas Measurement

§ 226.117 General requirements.

(a) Gas must be measured on the lease or cooperative agreement unit area from which it is produced unless approval for off-lease measurement is obtained pursuant to § 226.101.

(b) All bypasses of meters are prohibited.

(c) Tampering with any measurement device, component of a measurement device, or measurement process is prohibited. Violation of this prohibition will result in the assessment of the maximum penalty available under § 226.162(c).

§ 226.118 Timeframes for compliance.

(a) All equipment and procedures used to measure the volume of gas for royalty purposes after [effective date of final rule] must comply with the requirements in this subpart.

(b) All equipment and procedures used to measure the volume of gas for royalty purposes in use on [effective date of final rule] must comply with the requirements in this subpart by [one year from effective date of final rule]. Prior to that date, the equipment and procedures used to measure gas for royalty purposes must continue to comply with § 226.39, as it appears in 25 CFR part 226 (April 1, 2017, edition) and any applicable orders or notices.

§ 226.119 [Reserved]

§ 226.120 Specific performance requirements.

(a) *Flow rate measurement uncertainty levels.* (1) For high-volume FMPs, the measuring equipment must achieve an overall flow rate measurement uncertainty within +/− 3 percent.

(2) For very-high-volume FMPs, the measuring equipment must achieve an overall flow rate measurement uncertainty within +/− 2 percent.

(3) There are no measurement uncertainty requirements for low- and very-low-volume FMPs.

(4) The measurement uncertainty is based on the values of flowing parameters (*e.g.,* differential pressure, static pressure, and flowing temperature for differential meters or velocity, mass flow rate, and volumetric flow rate for linear meters) determined as follows, listed in order of priority:

(i) The average flowing parameters listed on the most recent daily QTR, if available to the Superintendent at the time of the uncertainty determination; or

(ii) The average flowing parameters from the previous day, as required under § 226.125(d)(4)(i) through (iii) (for differential meters).

(5) The uncertainty must be calculated in accordance with Section 12 of API 14.3.1 (incorporated by reference, see § 226.0) or other methods the Superintendent approves.

(b) *Heating value uncertainty levels.* (1) For high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within +/− 3 percent.

(2) For very-high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within +/− 2 percent.

(3) There are no heating value uncertainty requirements for low- and very-low-volume FMPs.

(4) Unless otherwise approved by the Superintendent, the average annual heating value uncertainty must be determined as follows:

$$U_{\overline{HV}} = 0.951 \times V_{95\%} \sqrt{\frac{1}{N}}$$

Where:

$U_{\overline{HV}}$ = average annual heating value uncertainty

$V_{95\%}$ = heating value variability

N = number of samples taken per year ($N = 1, 2, 4, 6, 12,$ or 26)

(c) *Bias.* For low-, high-, and very-high-volume FMPs, the measuring equipment used for either the flow rate or heating value determination must achieve measurement without statistically significant bias.

(d) *Verifiability.* The lessee must not use measurement equipment for which the Superintendent cannot independently verify the accuracy and validity of any input, factor, or equation used by the measuring equipment to determine quantity, rate, or heating value. Verifiability includes the ability to independently recalculate the volume, rate, and heating value based on source records and field observations.

§ 226.121 Flange-tapped orifice plate (primary devices).

(a) *Exemptions from requirements.* The standards and requirements in this section apply to all flange-tapped orifice plates subject to the following exceptions:

(1) Low-volume FMPs are exempt from the standards in paragraph (b) of this section; and

(2) Very-low-volume FMPs are exempt from the standards and requirements in paragraphs (b), (c), (f) and (l) of this section.

(b) *Orifice plate specifications.* Orifice plates must meet the requirements set forth in Section 4 of API 14.3.2 (incorporated by reference, see § 226.0) and the:

(1) Beta ratio must be no less than 0.10 and no greater than 0.75; and

(2) Orifice bore diameter must be no less than 0.45 inches.

(c) *Initial orifice plate inspection.* If an FMP measures oil from wells first coming into production or existing wells that have been re-fractured, the lessee must inspect the orifice plate upon installation and every two weeks thereafter until the production of particulate matter from the wells subsides. If the orifice plate does not comply with the requirements set forth in Subsection 4 of API 14.3.2 (incorporated by reference, see § 226.0), the lessee must replace it. Once the orifice plate complies with API 14.3.2, Subsection 4, the lessee must conduct inspections as set forth in paragraph (d) of this section.

(d) *Routine orifice plate inspection.* (1) Lessees must pull and inspect the orifice plate as follows:

(i) Once every 12 months for very-low-volume FMPs;

(ii) Once every 6 months for low-volume FMPs;

(iii) Once every 3 months for high-volume FMPs; and

(iv) Once a month for very-high-volume FMPs.

(2) If a routine inspection reveals that an orifice plate does not comply with Section 4 of API 14.3.2 (incorporated by reference, see § 226.0), the lessee must replace it.

(e) *Documentation of orifice plate inspections.* The lessee must document each orifice plate inspection and include that documentation as part of the verification report submitted in accordance with §§ 226.123 or 226.126. The documentation must include:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) The plate orientation (bevel upstream or downstream);

(5) The measured orifice bore diameter;

(6) The plate condition (documenting compliance with Section 4 of API 14.3.2 (incorporated by reference, see § 226.0);

(7) The presence of oil, grease, paraffin, scale, or other contaminants on the plate;

(8) The date and time of inspection; and

(9) Whether the plate was replaced.

(f) *Meter tube specifications.*

(1) Meter tubes must meet the requirements set forth in Subsections 5.1 through 5.4 of API 14.3.2 (incorporated by reference, see § 226.0). If flow conditioners are used, they must be isolating flow conditioners or 19-tube bundle flow straighteners constructed in compliance with Subsections 5.5.2 through 5.5.4 of API 14.3.2 and located in compliance with Subsection 6.3 of API 14.3.2 (all incorporated by reference, see § 226.0).

(2) Meter tube lengths and the location of 19-tube bundle flow straighteners, if applicable, must comply with the requirements set forth in Subsection 6.3 of API 14.3.2 (incorporated by reference, see § 226.0). If the diameter ratio falls between the values set forth in Subsection 6.3, Tables 7, 8a, or 8b of API 14.3.2 (incorporated by reference, see § 226.0), the length identified for the larger diameter ratio in the appropriate table is the minimum requirement for meter tube length and determines the location of the end of the 19-tube bundle flow straightener that is closest to the orifice plate.

(g) *Basic meter tube inspection.* The lessee must perform a basic inspection of meter tubes that can identify obstructions, pitting, and buildup of foreign substances within the following timeframe:

(1) *Frequency.* (i) Once every 10 years for low-volume and very-low-volume FMPs; and

(ii) Once every 5 years for high-volume and very-high-volume FMPs.

(2) *Corrective action.* If the basic meter tube inspection identifies obstructions, pitting, or buildup of foreign substances, the lessee must take one of the following corrective actions within 30 calendar days:

(i) For all FMPs, if the inspection only identifies the presence of an obstruction (such as debris in front of the flow conditioner), the lessee must remove the obstruction. If the inspection only identifies pitting, no corrective action is required;

(ii) For low- and very-low volume FMPs, if the inspection identifies the buildup of foreign substances, the lessee must clean the meter tube of such buildup; and

(iii) For high- and very-high-volume FMPs, if the inspection indicates pitting or the buildup of foreign substances, the lessee must clear or repair the meter tube and conduct a detailed meter tube inspection under paragraph (h) of this section; or

(iv) Submit a written request to the Superintendent for an extension of the 30-day corrective action timeframe, justifying the need for the extension and specifying the length of the extension requested.

(h) *Detailed meter tube inspection.* If a detailed meter tube inspection is required under paragraph (g)(2)(iii) of this section, the lessee must measure and inspect the meter tube to determine whether it complies with Subsections 5.1 through 5.4 of API 14.3.2 (incorporated by reference, see § 226.0). If the meter tube does not comply with the required standards, the lessee must repair or replace the meter tube and bring into compliance.

(i) *Documentation of meter tube inspections.* The lessee must document all inspections and make such documentation available to the Superintendent upon request. The documentation must include:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) The date and time of the inspection;

(5) The type of equipment used to perform the inspection;

(6) For a basic meter tube inspection, a description of findings, including the location and severity of pitting, obstructions, and buildup of foreign substances; and

(7) For detailed meter tube inspections, information demonstrating that the meter tube complies with Subsection 5.1 through 5.4 of API 14.3.2 (incorporated by reference, see § 226.0) and showing all required measurements.

(j) *Advance notice of inspections.* The lessee must notify the Superintendent at least 72 hours in advance of performing an inspection under paragraphs (d), (g), and (h) of this section or submit a monthly or quarterly schedule of inspections at least 15 calendar days prior to the date of the first inspection scheduled.

(k) *Other inspections.* The lessee must conduct additional inspections at the Superintendent's request.

(l) *Thermometer well.* Thermometer wells used for determining the flowing temperature of the gas and verification (test well), must be located in compliance with Subsection 6.5 of API 14.3.2 (incorporated by reference, see § 226.0). Where multiple thermometer wells have been installed in a meter tube, the flowing temperature must be measured from the thermometer well closest to the primary device. Thermometer wells used to measure or verify flowing temperature must contain a thermally conductive liquid.

(m) *Sampling probe.* The sampling probe must be located as specified in § 226.130.

§ 226.122 Mechanical recorder (secondary device).

(a) Mechanical recorders may be used as a secondary device on low- and very-low-volume FMPs only.

(b) Chart recorders used in conjunction with differential-type meters are approved for low- and very-low-volume FMPs only.

(c) Very-low-volume FMPs are exempt from the standards and requirements set forth paragraphs (e), (f), and (g) of this section.

(d) The connection between the pressure taps and the mechanical recorder must meet the following requirements:

(1) Gauge lines must:

(i) Have a nominal diameter of not less than 3⁄8 inch;

(ii) Be sloped upwards from the pressure taps at a minimum pitch of one inch per foot of length with no visible sag;

(iii) Have the same internal diameter along their entire length; and

(iv) Be no longer than 6 feet.

(2) Valves, including the valves in manifolds, must have a full-opening internal diameter of not less than 3/8 inch;

(3) There must not be any tees except for the static-pressure line; and

(4) There must be no connections to any other devices or more than one differential-pressure bellows and static pressure element.

(e) The differential-pressure pen must record at a minimum reading of 10 percent of the differential-pressure bellows range for the majority of the flowing period. This requirement does not apply to inverted charts.

(f) The flowing temperature of the gas must be continuously recorded and used in the volume calculations.

(g) The following information must always be maintained at the FMP in a legible condition and accessible to the Superintendent:

(1) The differential-pressure-bellows range;

(2) The static-pressure-element range;

(3) The temperature-element range;

(4) The relative density (specific gravity) of the gas;

(5) The static-pressure units of measure (psia or psig);

(6) The elevation of, or atmospheric pressure at, the FMP;

(7) The reference inside diameter of the meter tube;

(8) The primary device type;

(9) The orifice-bore or other primary device dimensions necessary for device verification, Beta or area ratio determination, and gas volume calculation;

(10) The location of isolating flow conditioners, if used;

(11) The location of the downstream end of the 19-tube-bundle flow straighteners, if used;

(12) The date of last primary device inspection; and

(13) The date of last meter verification.

(h) The differential pressure, static pressure, and flowing temperature elements must be operated between the lower- and upper-calibrated limits of the respective elements.

§ 226.123 Verification and calibration of mechanical recorder.

(a) *Verification following installation or repair.*

(1) Prior to performing any verification of a mechanical recorder, the lessee must perform a leak test. The test must be conducted in a manner that will detect leaks in all connections and fittings of the secondary device, including meter manifolds and verification equipment, isolation valves, and equalizer valves. If leaks are detected, the lessee must repair the leaks before proceeding with verification.

(2) The lessee must adjust the time lag between the differential- and static-pressure pens, if necessary, to be 1⁄96 of the chart rotation period measured at the chart hub.

(3) The meter's differential pen arc must be able to duplicate the test chart's time arc over the full range of the test chart and must be adjusted if necessary.

(4) The as-left values must be verified, in the following sequence, against a certified pressure device for the differential- and static-pressure elements (if the static-pressure pen has been offset for atmospheric pressure, the static-pressure element range is in psia):

(i) Zero (vented to atmosphere);

(ii) 50 percent of element range;

(iii) 100 percent of element range;

(iv) 80 percent of element range;

(v) 20 percent of element range; and

(vi) Zero (vented to atmosphere).

(5) The following as-left temperatures must be verified by placing the temperature probe in a water bath with a certified test thermometer:

(i) Approximately 10 °F below the lowest expected flowing temperature;

(ii) Approximately 10 °F above the highest expected flowing temperature; and

(iii) At the expected average flowing temperature.

(6) If any of the readings required in paragraph (a)(4) or (5) of this section vary from the test device reading by more than the following tolerance levels, the lessee must replace and verify the element for which readings were outside the applicable tolerances before returning the meter to service:

(i) Differential pressure element, +/−0.5 percent;

(ii) Static pressure element, +/−1.0 percent; and

(iii) Temperature element, +/−2 °F.

(7) If the static-pressure pen is offset for atmospheric pressure, the atmospheric pressure must be calculated in accordance with Appendix A to this part and the pen must be offset prior to obtaining the as-left verification values required in paragraph (a)(4) of this section.

(b) *Routine verification frequency.* The differential pressure bellows, static pressure element, and temperature element must be verified according to the requirements in this section at the following frequencies:

(1) Once every 6 months for very-low-volume FMPs; and

(2) Once every 3 months for low-volume FMPs.

(c) *Routine verification procedures.* (1) Prior to performing any verification required in this subpart, the lessee must perform a leak test in the manner specified in paragraph (a)(1) of this section.

(2) No adjustments to the pens or linkages may be made until an as-found verification is obtained. If the static pen has been offset for atmospheric pressure, the static pen must not be reset to zero until the as-found verification is obtained.

(3) The lessee must obtain and verify the as-found values of differential and static pressure against a certified pressure device at the readings listed in paragraph (a)(4) of this section, subject to the following additional requirements:

(i) If there is sufficient data on-site to determine the point at which the differential and static pens normally operate, the lessee must also obtain an as-found value at those points;

(ii) If sufficient data is not available on-site, the lessee must also obtain as-found values at 5 percent and 10 percent of the element range; and

(iii) If the static pressure pen has been offset for atmospheric pressure, the static-pressure element range is in units of psia.

(4) The as-found value for temperature must be taken using a certified test thermometer placed in a test thermometer well if there is flow through the meter and the meter tube is equipped with such a well. If there is no flow through the meter, or if the meter is not equipped with a test thermometer well, the temperature probe must be verified by placing it in an insulated water bath along with a test thermometer.

(5) The element undergoing verification must be calibrated according to manufacturer specifications if any of the as-found values determined under paragraph (c)(3) or (4) of this section are not within the tolerances specified in paragraph (a)(6) of this section, when compared to the values applied by the test equipment.

(6) The lessee must adjust the time lag between the differential- and static-pressure pens, if necessary, to be 1⁄96 of the chart rotation period, measured at the chart hub.

(7) The meter's differential pen arc must be able to duplicate the test chart's time arc over the full range of the test chart and must be adjusted if necessary.

(8) If any adjustment to the meter was made, the lessee must perform an as-left verification on each element adjusted using the procedures in paragraphs (c)(3) and (4) of this section.

(9) If, after an as-left verification, any of the readings required by paragraphs (c)(3) and (4) of this section vary by more than the tolerances set forth in paragraph (a)(6) of this section when compared with the test device reading, the lessee must replace and verify any element which has readings outside of the applicable tolerances under this section before returning the meter to service.

(10) If the static-pressure pen is offset for atmospheric pressure:

(i) The atmospheric pressure must be calculated in accordance with Appendix A to this part; and

(ii) The pen must be offset prior to obtaining the as-left verification values required in paragraph (c)(3) of this section.

(d) The lessee must retain documentation of each verification and make such documentation available to the Superintendent upon request. The documentation must include:

(1) The date and time of the verification;

(2) The date of the prior verification;

(3) Primary device data (reference inside diameter of the meter tube and differential-device size and Beta or area ratio) if the orifice plate is pulled and inspected;

(4) The type and location of taps (flange or pipe, upstream or downstream static tap);

(5) The atmospheric pressure used to offset the static-pressure pen, if applicable;

(6) Mechanical recorder data (differential pressure, static pressure, and temperature element ranges);

(7) The normal operating points for differential pressure, static pressure, and flowing temperature;

(8) The verification points (as-found and applied) for each element;

(9) The verification points (as-left and applied) for each element if a calibration is performed; and

(10) The name and contact information for each individual who performed or witnessed the verification, if applicable.

(e) *Notification of verification.* (1) For verifications performed after installation or following repair, the lessee must notify the Superintendent at least 72 hours before conducting the verification.

(2) For routine verifications, the lessee must notify the Superintendent at least 72 hours before conducting the verification or must submit a monthly or quarterly verification schedule to the Superintendent in advance.

(f) *Correction of reported volumes.* If during the verification, the combined errors in as-found differential pressure, static pressure, and flowing temperature taken at the normal operating points tested resulted in a flow-rate error greater than 2 percent and 2 Mcf/day, the volumes reported to ONRR must be corrected beginning with the date that the inaccuracy occurred. If such date is unknown, the volumes must be corrected beginning with the production month that includes the date that is halfway between the date of the last verification and the date of the current verification. Corrected reports must be submitted to ONRR within 30 calendar days of discovery of the error in the reported volumes.

(g) *Test equipment certification.* Test equipment used to verify or calibrate elements at an FMP must be certified at least once every two years. Documentation of the recertification must be available on site during all verifications and must show the:

(1) Test equipment serial number, make, and model;

(2) Date that recertification took place;

(3) Test equipment measurement range; and

(4) Uncertainty determined or verified as part of the recertification.

§ 226.124 Integration statements.

(a) The lessee must retain an unedited integration statement and make such statement available to the Superintendent upon request. The integration statement must contain the following:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) The name of the company performing the integration;

(5) The month and year to which the integration statement applies;

(6) The reference inside diameter of the meter tube (inches);

(7) The orifice bore diameter (inches) or Beta or area ratio and discharge coefficient, as applicable, and any other information necessary to calculate flow rate;

(8) The relative density (specific gravity);

(9) The CO_2 content (mole percent);

(10) The Dinitrogen (N_2) content (mole percent);

(11) The heating value calculated under § 226.140 (Btu/standard cubic feet);

(12) The atmospheric pressure or elevation at the FMP;

(13) The pressure base;

(14) The temperature base;

(15) The static-pressure tap location (upstream or downstream);

(16) The chart rotation (hours or days);

(17) The differential-pressure bellows range (inches of water);

(18) The static-pressure element range (psi); and

(19) For each chart integrated:

(i) The date and time on, and date and time off;

(ii) The average differential pressure (inches of water)

(iii) The average static pressure;

(iv) The static-pressure units of measure (psia or psig);

(v) The average temperature (°F);

(vi) The integrator counts or extension;

(vii) The hours of flow; and

(viii) The volume (Mcf).

(b) The volume for each chart integrated must be determined as follows:

$$V = IMV \times IV$$

Where:

V = reported volume, Mcf
IMV = integral multiplier value, as calculated under this section
IV = the integral value determined by the integration process (also known as the "extension," "integrated extension," and "integrator count")

(1) If the primary device is a flange-tapped orifice plate, a single IMV must be calculated for each chart or chart interval using the following equation:

$$IMV = 7709.61 \frac{C_d Y d^2}{\sqrt{1 - \beta^4}} \sqrt{\frac{Z_b}{G_r Z_f T_f}}$$

Where:

C_d = discharge coefficient or flow coefficient, calculated under API 14.3.3 or Section 5 of AGA Report No. 3 (both incorporated by reference, see § 226.0)
β = beta ratio
Y = gas expansion factor, calculated under Subsection 5.6 of API 14.3.3, or Section 5 of AGA Report No. 3 (both incorporated by reference, see § 226.0)
d = orifice diameter, in inches
Z_b = supercompressibility at base pressure and temperature
G_r = relative density (specific gravity)
Z_f = supercompressibility at flowing temperature and pressure
T_f = average flowing temperature, in degrees Rankine

(2) Variables that are functions of differential pressure, static pressure, or flowing temperature (*e.g.,* C_d, Y, Z_f) must use the average values of differential pressure, static pressure, and flowing temperature as determined from, and reported on, the integration statement for the chart or chart interval integrated. The flowing temperature must be the average flowing temperature reported on the integration statement for the chart or chart interval being integrated.

(c) Atmospheric pressure used to convert static pressure in psig to static pressure in psia, must be determined in accordance with Appendix A to this part.

§ 226.125 Electronic gas measurement (secondary and tertiary device).

(a) All electronic gas measurement systems (EGMs) must meet the requirements set forth in Section 9 and Subsection 4.4.5 of API 21.1 (incorporated by reference, see § 226.0).

(b) Very-low-volume FMPs are exempt from the standards and requirements set forth in paragraphs (c), (f), and (g) of this section.

(c) The connection between pressure taps and the secondary device must meet the following requirements:

(1) If gauge lines are used, they must:

(i) Have a nominal diameter of not less than 3⁄8 inch;

(ii) Be sloped upwards from the pressure taps at a minimum pitch of one inch per foot of length, with no visible sag;

(iii) Have the same internal diameter along their entire length; and

(iv) Be no longer than 6 feet.

(2) Valves, including the valves in manifolds, must have a full-opening internal diameter of not less than 3⁄8 inch;

(3) There must not be any tees, except for the static pressure line; and

(4) There must be no connections to any other devices or more than one differential pressure and static pressure transducer, except that where the lessee is employing redundancy verification, two differential pressure and two static pressure transducers may be connected.

(d) Each FMP must include a display that:

(1) Is readable without the need for data collection units, laptop computers, a password, or any special equipment;

(2) Is on-site and in a location that is accessible to the Superintendent;

(3) Includes the units of measure for each required variable;

(4) Displays the previous day's volume and the following variables consecutively:

(i) Current flowing static pressure with units (psia or psig);

(ii) Current differential pressure (inches of water);

(iii) Current flowing temperature (°F);

(iv) Current flow rate (Mcf/day or scf/day); and

(5) Displays an hourly or daily QTR no more than 31 calendar days old and shows the following information:

(i) The previous period (for this section, previous period means at least 1 day prior, but no longer than 1 month prior) average differential pressure (inches of water);

(ii) The average static pressure with units (psia or psig); and

(iii) The average flowing temperature (°F).

(e) The lessee must always maintain the following at the FMP in legible condition and accessible to the Superintendent:

(1) The unique meter identification number;

(2) The relative density (specific gravity);

(3) The elevation of, or the atmospheric pressure at, the FMP;

(4) Primary device information, such as orifice bore diameter (inches) or Beta or area ratio and discharge coefficient, as applicable;

(5) The reference inside diameter of meter tube;

(6) The make, model, and location of isolating flow conditioners, if used;

(7) The location of the downstream end of 19-tube-bundle flow straighteners, if used;

(8) The upper calibrated limit for each transducer;

(9) The location of the static-pressure tap (upstream or downstream);

(10) The date of last orifice plate inspection;

(11) The date of last meter tube inspection; and

(12) The date of last secondary device inspection.

(f) The differential pressure, static pressure, and flowing temperature transducers must be operated between the upper and lower calibrated limits of the transducer.

(g) The flowing temperature of the gas must be continuously measured and used in the flow-rate calculations in accordance with Section 4 of API 21.1 (incorporated by reference, see § 226.0).

§ 226.126 Verification and calibration of electronic gas measurement systems.

(a) *Transducer verification and calibration after installation or repair.* (1) Prior to performing any verification required in this section, the lessee must perform a leak test in the manner set forth in § 226.123(a)(1).

(2) The lessee must verify the points listed in Subsection 7.3.3 of API 21.1 (incorporated by reference, see § 226.0), by comparing the values from the certified test device with the values used by the flow computer to calculate flow rate. If any of these as-left readings vary from the test equipment reading by more than the tolerance calculated using Subsection 8.2.2.2, Equation 24 of API 21.1 (incorporated by reference, see § 226.0), the transducer must be replaced and tested under this paragraph.

(3) For absolute static pressure transducers, the value of atmospheric pressure used when the transducer is vented to atmosphere must be calculated in accordance with Appendix A to this part, measured by a NIST-certified barometer with a stated accuracy of +/−0.06 psi (±4 millibars) or better, or obtained from an absolute pressure calibration device.

(4) Prior to putting the meter into service, the differential pressure transducer must be tested at zero with full working pressure applied to both sides of the transducer. If the absolute value of the transducer reading is greater than the reference accuracy of the transducer, expressed in inches of water column, the transducer must be re-zeroed.

(b) *Routine verification frequency.* (1) If redundancy verification under paragraph (d) of this section is not used, the differential pressure, static pressure, and temperature transducers must be verified in accordance with the procedures set forth in paragraph (c) of this section at the following frequencies:

(i) Once every 24 months for low-volume and very-low-volume FMPs;

(ii) Once every 6 months for high-volume and very-high-volume FMPs.

(2) If redundancy verification under paragraph (d) of this section is used, the differential pressure, static pressure, and temperature transducers must be verified in accordance with the procedures set forth therein. In addition, the temperature transducers must be verified in accordance with the procedures set forth in paragraph (c) of this section at least once a year.

(c) *Routine verification procedures.* Verifications must be performed in accordance with Subsection 8.2 of API 21.1 (incorporated by reference, see § 226.0), subject to the following exceptions, additions, and clarifications:

(1) Prior to performing any verification required under this section, the lessee must perform a leak test in the manner set forth in § 226.123(a)(1).

(2) An as-found verification for differential pressure, static pressure, and temperature must be conducted at the normal operating point of each transducer.

(i) The normal operating point is the mean value taken over a previous time period that is not less than one day, or greater than one month, prior. Acceptable mean values include means that are weighted based on flow time and flow rate.

(ii) For differential and static pressure transducers, the pressure applied to the transducer must be within five percentage points of the normal operating point.

(iii) For the temperature transducer, the water bath or test thermometer well must be within 20 °F of the normal operating point for temperature.

(3) If a transducer is calibrated, the as-left verification must include the normal operating point of that transducer, as defined in paragraph (c)(2) of this section.

(4) The as-found values for differential pressure obtained with the low side vented to atmospheric pressure must be corrected to working pressure values using Annex H, Equation H.1 of API 21.1 (incorporated by reference, see § 226.0).

(5) The verification tolerance for differential and static pressure is calculated using Subsection 8.2.2.2, Equation 24 of API 21.1 (incorporated by reference, see § 226.0). The verification tolerance for temperature is equivalent to the uncertainty of the temperature transmitter or 0.5 °F, whichever is greater.

(6) All required verification points must be within the applicable verification tolerance before returning the meter to service.

(7) Prior to putting a meter into service, the differential pressure transducer must be tested at zero with full working pressure applied to both sides of the transducer. If the absolute value of the transducer reading is greater than the reference accuracy of the transducer, as expressed in inches of water column, the transducer must be re-zeroed.

(d) *Redundancy verification procedures.* Redundancy verification must be performed as required under Subsection 8.2 of API 21.1 (incorporated by reference, see § 226.0), subject to the following exceptions, additions, and clarifications:

(1) The lessee must identify which set of transducers is used for reporting on the Form ONRR–4054 (the primary transducers) and which set of transducers is used as a check (the check set of transducers);

(2) For every calendar month, the lessee must compare the flow-time linear averages of differential pressure, static pressure, and temperature readings from the primary transducers with those from the check transducers; and

(3) If for any transducer the difference between the averages exceeds the tolerance defined by the equation below, the lessee must verify both the primary and check transducer under paragraph (c) of this section within the first five days of the month following the month in which the redundancy verification was performed. For example, if the redundancy verification for March reveals that the difference in flow-time linear averages of differential pressure exceeded the verification tolerance, both the primary and check differential-pressure transducers must be verified under paragraph (c) of this section by April 5th.

$$Tolerance = \sqrt{A_P^2 + A_C^2}$$

Where:

A_P is the reference accuracy of the primary transducer and

A_C is the reference accuracy of the check transducer

(e) *Documentation of verifications.* The lessee must retain documentation of each verification and make such documentation available to the Superintendent upon request. The documentation must include the following:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) The date and time of verification, and date of the last verification;

(5) Primary device information (reference inside diameter of the meter tube and orifice plate or differential device size, and Beta or area ratio);

(6) The type and location of taps (flange or pipe, upstream or downstream, static tap);

(7) The upper calibrated limit for each transducer;

(8) The normal operating points for differential pressure, static pressure, and flowing temperature;

(9) The atmospheric pressure;

(10) The verification points (as-found and applied) for each transducer;

(11) The verification points (as-left and applied) for each transducer if calibration was performed;

(12) The differential device date of inspection and condition (*e.g.,* clean, sharp edge, or surface condition);

(13) The verification equipment make, model, range, accuracy, and date of last certification; and

(14) The name(s) and contact information for individuals that performed or witnessed the verification, if applicable.

(f) *Notification of verification.* (1) The lessee must notify the Superintendent at least 72 hours before conducting verifications after installation or following repair.

(2) The lessee must notify the Superintendent at least 72 hours before conducting routine verifications or provide the Superintendent with a monthly or quarterly verification schedule in advance.

(g) *Correction of reported volumes.* If during the verification, the combined errors in as-found differential pressure, static pressure, and flowing temperature taken at the normal operating points tested result in a flow-rate error greater than 2 percent and 2 Mcf/day, the volumes reported to ONRR must be corrected beginning with the date that the inaccuracy occurred. If that date is unknown, the volumes must be corrected beginning with the production month that includes the date that is halfway between the date of the last verification and the date of the present verification. Corrected reports must be submitted to ONRR within 30 calendar days of discovery of the error in the reported volumes.

(h) *Certification of test equipment.* Test equipment used to verify or calibrate transducers at an FMP must be certified at least once every two years. Documentation of the certification must be on-site and available to the Superintendent during all verifications. Such documentation must show the:

(1) Test equipment serial number, make and model;

(2) Date that recertification took place;

(3) Test equipment measurement range; and

(4) Uncertainty determined or verified as part of the recertification.

(i) *Accuracy standards for test equipment.* Test equipment used to verify or calibrate transducers at an FMP must meet the following accuracy standards:

(1) The accuracy of the test equipment, stated in actual units of measure, must be no greater than 0.5 times the reference accuracy of the transducer being verified, also stated in actual units of measure; or

(2) The equipment must have a stated accuracy of 0.10 percent of the upper calibrated limit of the transducer being verified.

§ 226.127 Flow rate, volume, and average value calculation.

(a) For flange-tapped orifice plates, the flow rate must be calculated under:

(1) Sections 4 and 5 of API 14.3.3 (incorporated by reference, see § 226.0); and

(2) AGA Report No. 8 (incorporated by reference, see § 226.0), for supercompressibility.

(b) Atmospheric pressure used to convert static pressure in psig to static pressure in psia must be determined using Appendix A of this part.

(c) Hourly and daily gas volumes, average values of the live input variables, flow time, and integral value or average extension required under § 226.128 must be determined using Section 4 and Annex B of API 21.1 (incorporated by reference, see § 226.0).

§ 226.128 Logs and records.

(a) The lessee must retain, and make available to the Superintendent upon request, the original, unaltered, unprocessed, and unedited daily and hourly QTRs, which must contain the information identified in Subsection 5.2 of API 21.1 (incorporated by reference, see § 226.0), subject to the following additions and clarifications:

(1) The QTRs must contain the lessee's name, lease number, and well or facility name and number;

(2) The volume, flow time, and integral value or average extension must be reported to at least five significant digits;

(3) The average differential pressure, static pressure, and temperature, as calculated in § 226.127(c), must be reported to at least three significant digits; and

(4) The QTRs must include a statement indicating whether the lessee submitted the integral value or average extension.

(b) The lessee must retain, and make available to the Superintendent upon request, the original unaltered, unprocessed, and unedited configuration log, which must contain the information specified in Subsection 5.4 (including the flow-computer snapshot report in Subsection 5.4.2) of API 21.1 and Annex G of API 21.1 (both incorporated by reference, see § 226.0), as well as the following:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) For very-low-volume FMPs only, the fixed temperature, if not continuously measured (°F); and

(5) The static-pressure tap location (upstream or downstream).

(c) The lessee must retain, and make available to the Superintendent upon request, the original, unaltered, unprocessed, and unedited event log. The event log must comply with the requirements set forth in Subsection 5.5 of API 21.1 (incorporated by reference, see § 226.0), and must have sufficient capacity to be retrieved and stored at intervals that will maintain a continuous record of events for the required six-year retention period or the life of the FMP, whichever is shorter.

(d) The lessee must retain, and make available to the Superintendent upon request, an alarm log. The alarm log must comply with the requirements set forth in Subsection 5.6 of API 21.1 (incorporated by reference, see § 226.0).

§ 226.129 Gas sampling and analysis.

(a) Samples must be taken using one of the following methods:

(1) Spot sampling under §§ 226.131, 226.132, and 226.133;

(2) Flow-proportional composite sampling under § 226.134; or

(3) On-line gas chromatograph under § 226.135.

(b) At all times during the sampling process, the minimum temperature of all gas sampling components must be the lesser of:

(1) The flowing temperature of the gas measured at the time of sampling; or

(2) 30 °F above the calculated hydrocarbon dew point of the gas.

§ 226.130 Sampling probe and tubing.

(a) *Exemptions.* Very-low-volume FMPs are exempt from the standards and requirements set forth in this section.

(b) *Location of sample probe.* (1) The sampling probe must be located as specified in Subsection 6.4.2 of API 14.1 (incorporated by reference, see § 226.0) and must be the first obstruction downstream of the primary device.

(2) The sample probe must be exposed to the same ambient temperature as the primary device. The lessee may accomplish this by physically locating the sample probe in the same ambient temperature conditions as the primary device (such as in a heated meter house) or by installing insulation and/or heat tracing along the entire meter run.

(c) *Sample probe design and type.* (1) Sample probes must be made from stainless steel.

(2) If a regulating type of sample probe is used, the pressure-regulating mechanism must be inside the pipe or maintained at a temperature of at least 30 °F above the hydrocarbon dew point of the gas.

(3) The sample probe length must be the shorter of the:

(i) Length necessary to place the collection end of the probe in the center one-third of the pipe cross-section; or

(ii) Recommended probe length in Subsection 6.4, Table 1 of API 14.1 (incorporated by reference, see § 226.0).

(4) The use of membranes, screens, or filters at any point in the sample probe is prohibited.

(d) *Sample tubing type.* Sample tubing connecting the sample probe to the sample container or analyzer must be made of stainless steel or nylon 11.

§ 226.131 Spot samples—general requirements.

(a) *Sampling while flowing.* The FMP must be flowing when a gas sample is taken. If an FMP is in non-flowing status on the date that a sample is due under § 226.133, no sample is required. The lessee must take a sample within 15 calendar days of the date that flow to the FMP is reinitiated. For purposes of this section, non-flowing status means there has been no flow through the FMP for at least 30 consecutive days. Non-flowing status does not apply to meters at FMPs that flow intermittently on a daily or weekly basis.

(b) *Notice of spot samples.* The lessee must provide the Superintendent with at least 72 hours' advance notice before obtaining a spot sample or submit a monthly or quarterly sampling schedule to the Superintendent in advance of taking samples.

(c) *Sample cylinder requirements.* Sample cylinders must:

(1) Comply with the requirements set forth in Subsection 9.1 of API 14.1 (incorporated by reference, see § 226.0);

(2) Have a minimum capacity of 300 cubic centimeters; and

(3) Be cleaned prior to sampling in accordance with Appendix A of GPA 2166–17 (incorporated by reference, see § 226.0) or an equivalent method. The lessee must maintain documentation of cleaning, have the documentation on-site during sampling, and provide the documentation to the Superintendent upon request.

(d) *Spot sampling using portable gas chromatographs.* (1) If used, sampling separators must be:

(i) Constructed of stainless steel;

(ii) Cleaned prior to sampling in accordance with Appendix A of GPA 2166–17 (incorporated by reference, see § 226.0) or an equivalent method. The lessee must maintain documentation of cleaning, have the documentation on-site during sampling, and provide the documentation to the Superintendent upon request; and

(iii) Operated under Appendix B.3 of GPA 2166–17 (incorporated by reference, see § 226.0).

(2) The sample port and inlet to the sample line must be purged using the gas being sampled before completing the connection between them.

(3) The portable gas chromatograph must be operated, verified, and calibrated as set forth in § 226.136 and documentation of such verification and calibration must be available for inspection by the Superintendent at the time of sampling.

(4) The documentation of verification or calibration required in § 226.136(e) must be available for the Superintendent's inspection at the time of sampling.

(5) The minimum number of samples and analyses is as follows:

(i) For low-volume and very-low-volume FMPs, at least three samples must be taken and analyzed;

(ii) For high-volume FMPs, samples must be taken and analyzed until the difference between the maximum and minimum heating values calculated based on three consecutive analyses is less than or equal to 16 Btu/scf; and

(iii) For very-high-volume FMPs, samples must be taken and analyzed until the difference between the maximum and minimum heating values calculated based on three consecutive analyses is less than or equal to 8 Btu/scf.

(6) Unless the Superintendent approves an alternative method of calculation, the heating value and relative density used for reporting to ONRR must be either the mean or median heating value and relative density calculated from the three analyses required in paragraph (d)(5) of this section.

§ 226.132 Spot samples—allowable methods.

(a) Spot samples must be obtained using one of the following methods:

(1) *Purging—fill and empty method.* Samples taken using this method must comply with the requirements set forth in Section 9.1 of GPA 2166–17 (incorporated by reference, see § 226.0);

(2) *Helium "pop" method.* Samples taken using this method must comply with the requirements set forth in Section 9.5 of GPA 2166–17 (incorporated by reference, see § 226.0). The lessee must maintain documentation demonstrating that the cylinder was evacuated and pre-charged before sampling and make such documentation available to the Superintendent upon request;

(3) *Floating piston cylinder method.* Samples taken using this method must comply with the requirements set forth in Sections 9.7.1 and 9.7.3 of GPA 2166–17 (incorporated by reference, see § 226.0). The lessee must maintain documentation of the seal material and type of lubricant used and make such documentation available to the Superintendent upon request;

(4) *Portable gas chromatograph.* Samples taken using this method must comply with § 226.136; or

(5) *Alternative methods.* Other methods the Superintendent approves.

(b) If the lessee uses the sampling methods in paragraph (a)(1) or (2) of this section and the flowing pressure at the sample port is less than or equal to 15 psig, the lessee may also employ a vacuum gathering system. Samples taken using a vacuum-gathering system must comply with the requirements set forth in Subsection 11.10 of API 14.1 (incorporated by reference, see § 226.0) and the samples must be obtained from the discharge of the vacuum pump.

§ 226.133 Spot samples—frequency.

(a) Spot samples must be taken and analyzed at the following frequencies:

(1) Once every 12 months for very-low-volume FMPs;

(2) Once every 6 months for low-volume FMPs;

(3) One every 3 months for high-volume FMPs; and

(4) Once a month for very-high-volume FMPs.

(b) The Superintendent may change the required sampling frequency for high- and very-high-volume FMPs if a determination is made that the frequency under paragraph (a) of this section does not achieve the heating value uncertainty levels required in § 226.120(b).

(1) The Superintendent may change the sampling frequency no sooner than [two years from effective date of final rule].

(2) The new sampling frequency will remain in effect until the heating value variability justifies a different frequency.

(3) The Superintendent may not change the sampling frequency to more than once every two weeks or less than once every six months.

(c) The time between any two spot samples must not exceed:

(1) 18 calendar days, if the required sampling frequency is every two weeks;

(2) 45 calendar days, if the required sampling frequency is once a month;

(3) 105 calendar days, if the required sampling frequency is once every 3 months;

(4) 195 calendar days, if the required sampling frequency is once every 6 months; and

(5) 380 calendar days, if the required sampling frequency is once every 12 months.

§ 226.134 Composite sampling methods.

(a) Composite samplers must be flow-proportional.

(b) Samples must be collected using a positive-displacement pump.

(c) Sample cylinders must be sized to ensure the cylinder capacity is not exceeded within the normal collection frequency.

§ 226.135 On-line gas chromatographs.

(a) On-line gas chromatographs must be installed, operated, and maintained in accordance with, Appendix D of GPA 2166–17 (incorporated by reference, see § 226.0), and the manufacturer's specifications, instructions, and recommendations.

(b) On-line gas chromatographs must comply with the verification and calibration requirements set forth in § 226.136. The lessee must maintain documentation of verifications and calibrations and make such documentation available to the Superintendent upon request.

§ 226.136 Gas chromatographs.

(a) All gas chromatographs must be installed, operated, and calibrated in accordance with GPA 2261–20 (incorporated by reference, see § 226.0).

(b) Gas chromatographs must be verified under the requirements in paragraph (c) of this section not less than once every seven calendar days.

(c) Verifications must be performed in accordance with 2261–20 (incorporated by reference, see § 226.0), with the following additions and clarifications:

(1) All gases used for verification and calibration must meet the standards of Sections 3 and 4 of GPA 2198–16 (incorporated by reference, see § 226.0);

(2) All new gases used for verification and calibration must be authenticated prior to verification or calibration in accordance with Section 6 of GPA 2198–16 (incorporated by reference, see § 226.0);

(3) The gas used to calibrate a gas chromatograph must be maintained in accordance with Section 5 of GPA 2198–16 (incorporated by reference, see § 226.0);

(4) If the composition of the gas used for verification as determined by the gas chromatograph varies from the certified composition of the gas used for verification by more than the reproducibility values in Section 10 of GPA 2261–20, the gas chromatograph must be calibrated in accordance with Section 6 of GPA 2261–20 (both incorporated by reference, see § 226.0); and

(5) If the gas chromatograph is calibrated, it must be re-verified under paragraph (c)(4) of this section.

(d) Samples must be analyzed until the un-normalized sum of the mole percent of all gases analyzed is between 97 and 103 percent.

(e) The lessee must retain documentation of the verifications and make such documentation available to the Superintendent upon request. The documentation must include:

(1) The components analyzed;

(2) The response factor for each component;

(3) The peak area for each component;

(4) The mole percent of each component as determined by the gas chromatograph;

(5) The mole percent of each component in the gas used for verification;

(6) The difference between the mole percentages determined in paragraphs (e)(4) and (5) of this section, expressed in relative percent;

(7) Evidence that the gas used for verification and calibration:

(i) Meets the requirements of paragraph (c)(2) of this section, including a unique identification number of the calibration gas used, the name of the supplier of the calibration gas, and the certified list of the mole percent of each component in the calibration gas;

(ii) Was authenticated under paragraph (c)(3) of this section prior to verification or calibration, including the fidelity plots; and

(iii) Was maintained under paragraph (c)(4) of this section, including the fidelity plot made as part of the calibration run;

(8) The chromatograms generated during the verification process;

(9) The time and date the verification was performed; and

(10) The name and affiliation of the person performing the verification.

§ 226.137 Components to analyze.

(a) Low- and very-low-volume FMPs are exempt from the standards and requirements set forth in paragraphs (c), (d), and (e) of this section.

(b) Gas must be analyzed for the following components:

(1) Methane;

(2) Ethane;

(3) Propane;

(4) Isobutane;

(5) Normal Butane;

(6) Pentanes;

(7) Hexanes + (C_6+);

(8) Carbon dioxide; and

(9) Nitrogen.

(c) When the concentration of C_6+ exceeds 0.5 mole percent, hexanes, heptanes, octanes, and Nonanes-plus (C_9+) must also be analyzed.

(d) In lieu of testing each sample for the components required under paragraph (c) of this section, the lessee may periodically test for these components and adjust the assumed C_6+ composition to remove bias in the heating value. The adjusted C_6+ composition must be applied to the mole percent of C_6+ analyses until the next analysis is done under paragraph (c) of this section.

(e) The minimum analysis frequency for components listed in paragraph (c) of this section is:

(1) Once every 12 months, for high-volume FMPs; and

(2) Once every 6 months, for very-high-volume FMPs.

§ 226.138 Gas analysis report requirements.

(a) The gas analysis report must contain the following information:

(1) The lessee's name;

(2) The lease number;

(3) The well or facility name and number;

(4) The date and time the sample or spot samples were taken or, for composite samples, the date the cylinder was installed and date it was removed;

(5) The date and time of the analysis;

(6) For spot samples, the effective date, if other than the date of sampling;

(7) For composite samples, the effective start and end dates;

(8) The name of the laboratory where the analysis was performed, if applicable;

(9) The device used for analysis (*i.e.,* gas chromatograph, calorimeter, or mass spectrometer);

(10) The make and model of the analyzer;

(11) The date of the last verification or calibration of the analyzer;

(12) The flowing temperature at the time of sampling;

(13) The flowing pressure at the time of sampling, including units of measure (psia or psig);

(14) The flow rate at the time of sampling;

(15) The ambient air temperature at the time of sampling;

(16) Whether or not heat trace or any other method of heating was used;

(17) The type of sample (*i.e.,* spot-cylinder, spot-portable gas chromatograph, composite);

(18) The sampling method if spot-cylinder (*e.g.,* fill and empty, helium pop);

(19) A list of the components tested;

(20) The total un-normalized mole percent of the components tested;

(21) The normalized mole percent of each component tested, including a summation of those mole percentages;

(22) The ideal heating value (Btu/scf);

(23) The real heating value (Btu/scf), dry basis;

(24) The hexanes-plus heating value (Btu/scf), if applicable;

(25) The pressure base and temperature base;

(26) The relative density; and

(27) The name of company obtaining the gas sample.

(b) Components that are listed on the analysis report but are not tested must be annotated as such.

(c) The heating value and relative density must be calculated using API 14.5 (incorporated by reference, see § 226.0).

(d) The base supercompressibility must be calculated using AGA Report No. 8 (incorporated by reference, see § 226.0).

(e) The lessee must submit all gas analysis reports to the Superintendent within 14 calendar days after the due date for the sample as specified in § 226.133.

§ 226.139 Effective date of a spot or composite gas sample.

(a) Unless otherwise specified in the gas analysis report, the effective date of a spot sample is the date on which the sample was taken. The effective date of a spot sample may be no later than the first day of the production month following the lessee's receipt of the laboratory analysis of the sample.

(b) Unless otherwise specified in the gas analysis report, the effective date of a composite sample is the first day of the month in which the sample was removed.

§ 226.140 Calculation of heating value and volume.

(a) *Heating value of sample.* The heating value of gas sampled must be calculated as follows:

(1) Gross heating value is defined in Subsection 3.7 of API 14.5, and must be calculated using Subsection 7.1 of API 14.5 (incorporated by reference, see § 226.0); and

(2) Real heating value must be calculated by dividing the gross heating value of the gas calculated under paragraph (a)(1) of this section by the compressibility factor of the gas at 14.73 psia and 60 °F.

(b) *Average heating value.* (1) If a lease has more than one FMP, the average heating value for the lease for a reporting month must be the volume-weighted average of heating values, calculated as follows:

$$\overline{HV} = \frac{\sum_{i=1}^{i=n}(HV_i \text{ x } V_i)}{\sum_{i=1}^{i=n} V_i}$$

Where:

$\overline{HV}$ = the average heating value for the lease for the reporting month, in Btu/scf

HV_i = the heating value for FMP_i during the reporting month (see § 226.140(a)(2), if an FMP has multiple heating values during the reporting month), in Btu/scf

V_i = the volume measured by FMP_i during the reporting month, in Btu/scf

i = each FMP for the lease

n = the number of FMPs for the lease

(2) If the effective date of a heating value for an FMP is other than the first day of the reporting month, the average heating value of the FMP must be the volume-weighted average of heating values, determined as follows:

$$HV_i = \frac{\sum_{j=1}^{j=m}(HV_{i,j} \text{ x } V_{i,j})}{\sum_{j=1}^{j=m} V_{i,j}}$$

Where:

HV_i = the heating value for FMP_i, in Btu/scf

$HV_{i,j}$ = the heating value for FMP_i, for partial month *j*, in Btu/scf

$V_{i,j}$ = the volume measured by FMP_i, for partial month *j*, in Btu/scf

i = represents each FMP for the lease

j = represents a partial month for which heating value $HV_{i,j}$ is effective

m = the number of different heating values in a reporting month for an FMP

(c) *Calculation of volume.* The volume must be determined under § 226.124(b) and (c) (mechanical recorders) or § 226.125(c) (electronic gas measurement systems).

§ 226.141 Reporting of heating value and volume.

(a) *Reported gross and real heating values.* The gross heating value and real heating value, or average gross heating value and average real heating value, as applicable, derived from all samples and analyses must be reported to ONRR in units of Btu/scf under the following conditions:

(1) Containing no water vapor (''dry''), unless the water vapor content has been determined through actual on-site measurement, included in heating value calculations, and reported on the gas analysis report. The heating value may not be reported based on assumed water vapor content. Acceptable methods of measuring water vapor are chilled mirror and other methods the Superintendent approves;

(2) Adjusted to a pressure of 14.73 psia and a temperature of 60 °F; and

(3) For samples analyzed under § 226.137(a), notwithstanding any provision of a contract between the lessee and purchaser or transporter, the composition of hexanes + must have a heating value of not less than:

(i) 5,129 Btu/scf (equivalent heating value of 60 percent hexanes, 30 percent heptanes, and 10 percent octanes); or

(ii) The heating value of the C_9+ composition determined under § 226.137(c).

(b) *Reported volume.* The volume for royalty purposes must be reported to ONRR in units Mcf, as follows:

(1) The volume must not be adjusted for water-vapor content or any other factors that are not included in calculations required in § 226.124(b) and (c) or § 226.127; and

(2) The volume must match the monthly volume(s) shown in the unedited QTR(s) or integration statement(s) unless edits to the data are documented under paragraph (c) of this section.

(c) *Edits and adjustments to reported heating value or volume.* (1) If there are measurement errors stemming from an equipment malfunction that results in discrepancies in the calculated heating value or volume of the gas, the heating value or volume reported during the period in which the error persisted must be estimated.

(2) All edits made to the data before the report is submitted to ONRR must be documented and include verifiable justifications for the edits made. Such documentation must be available to the Superintendent and ONRR upon request.

(3) All values on daily and hourly QTRs that have been changed or edited must be clearly identified and cross referenced to the justification required in paragraph (c)(2) of this section.

(4) The volumes reported to ONRR must be corrected beginning with the date that the inaccuracy occurred. If the date is unknown, the volumes must be corrected beginning with the production month that includes the date that is halfway between the date of the previous verification and the date of the most recent verification. Corrected reports must be submitted to ONRR within 30 calendar days of discovery of the error in the reported volumes.

Subpart L—Tribal and Royalty-Free Use of Production

Tribal Use of Gas Production

§ 226.142 Use of gas by the Osage Nation and Tribe members.

(a) Gas from any well must be furnished to any Tribally-owned building or enterprise at a rate not to exceed the rate set forth in § 226.40, subject to the Superintendent's determination that the lease is producing gas in excess of the lessee's requirements for operations and that no waste will result. The Osage Nation must furnish all labor and materials necessary for connection with the lessee's gas system. The Osage Nation uses gas under this section at its own risk.

(b) Any member of the Osage Nation who resides in Osage County outside of an incorporated city is entitled to use a maximum of 400,000 cubic feet of gas per calendar year for their primary residence at a rate not to exceed the rate set forth in § 226.40, subject to the Superintendent's determination that the lease is producing gas in excess of the lessee's requirements and that no waste will result. The Tribe member must furnish all labor and materials necessary for connection with the lessee's gas system and must maintain their own lines. Tribal members use gas under this section at their own risk.

(c) The lessee may not stop furnishing gas pursuant to paragraphs (a) and (b) of this section without Superintendent's approval. To obtain such approval, the lessee must submit a request to the Superintendent, in writing, providing justification for terminating the Tribe member's use of gas from the lessee's well.

§ 226.143 Royalty on gas furnished for Tribal use.

The lessee must pay royalty on all gas furnished to Tribally owned buildings and enterprises and Tribe members in accordance with §§ 226.39 and 226.40.

Royalty-Free Use of Lease Production

§ 226.144 Production on which no royalty is due.

To the extent specified in §§ 226.145 and 226.146, royalty is not due on:

(a) Oil and gas produced from a lease and used for operations or production purposes (including placing the oil and gas in marketable condition) on the same lease without being removed therefrom; or

(b) Oil and gas produced from a unit and used for operations or production purposes (including placing the oil and gas in marketable condition) on the same unit, under the same cooperative agreement, without being removed therefrom.

§ 226.145 Uses of production on a lease or unit that do not require the Superintendent's prior approval of royalty-free treatment.

(a) The following uses of oil and gas for operations or production purposes do not require the Superintendent's prior approval to be royalty-free:

(1) Use of fuel to generate power or operate combined heat and power;

(2) Use of fuel to power equipment, including artificial lift equipment, equipment used for enhanced recovery, drilling rigs, and completion and workover equipment;

(3) Use of gas to actuate pneumatic controllers or operate pneumatic pumps at production facilities;

(4) Use of fuel to heat, separate, or dehydrate production;

(5) Use of gas as a pilot fuel or as assist gas for a flare, combustor, thermal oxidizer, or other control device;

(6) Use of fuel to compress or treat gas to place it in marketable condition;

(7) Use of oil to clean the well and improve production (*e.g.,* hot oil treatments). The lessee must document removal of the oil from the tank or pipeline in accordance with § 226.99;

(8) Use of oil as a circulating medium in drilling operations if such use is part of an approved drilling plan;

(9) Injection of gas for the purpose of conserving gas or increasing the recovery of oil or gas if the Superintendent ordered or approved such injection; and

(10) Injection of gas that is cycled in a contained gas-lift system.

(b) The volumes of oil and gas treated as royalty-free under this section must not exceed the amount of fuel necessary to perform the operation using equipment of appropriate capacity.

§ 226.146 Uses of production on a lease or unit that require the Superintendent's prior approval of royalty-free treatment.

(a) The following uses of oil and gas for operations or production purposes require the Superintendent's prior approval of royalty-free treatment to ensure that accountability is maintained:

(1) Use of oil or gas the lessee removes from the pipeline at a location downstream of the FMP;

(2) Use of gas that has been removed from the lease or unit for treatment or processing because the physical characteristics of the gas require it to be treated or processed prior to use, where the gas is returned to, and used on, the same lease or unit from which it was produced; and

(3) Any other uses of produced oil and gas for operations and production purposes that are not set forth in § 226.145.

(b) The lessee must submit a request to conduct activities under paragraph (a) of this section to the Superintendent, in writing, to obtain approval of royalty-free treatment for the volumes of oil and gas used. Such request must include the information required by § 226.151. If the Superintendent approves a request for royalty-free treatment under this section, the effective date of such approval will be the date the Superintendent received the lessee's request. If the Superintendent denies a request for royalty-free treatment under this section, the lessee must pay royalties on all volumes utilized to conduct activities under paragraph (a) of this section.

(c) The lessee must measure the volumes of oil and gas used to conduct activities under paragraph (a)(1) of this section in accordance with subparts J and K, as applicable. The lessee must measure the volume of gas returned to the lease or unit following removal under paragraph (a)(2) of this section in accordance with subpart K.

§ 226.147 Uses of production moved off the lease or unit that do not require the Superintendent's prior approval of royalty-free treatment.

Oil and gas moved off the lease or unit may be treated as royalty-free without the Superintendent's prior approval if the use meets the criteria in § 226.145 and:

(a) The oil or gas is transported from one area of the lease or unit to be used at another area of the same lease or unit and no oil or gas is added to, or removed from, the pipeline while crossing lands that are not part of the lease or unit from which the oil or gas was produced; or

(b) A well is directionally drilled, the wellhead is not located on the producing lease or unit, and the oil or gas is being used on the same well pad for operations or production purposes for that well.

§ 226.148 Uses of production moved off the lease or unit that require the Superintendent's prior approval of royalty-free treatment.

(a) Except as provided in § 226.147(b) and paragraph (b) of this section, royalty is owed on all oil and gas used in operations conducted off the lease or unit from which it is produced.

(b) The Superintendent may grant prior approval of royalty-free treatment of oil or gas used in operations conducted off the lease or unit if the:

(1) Use is among those listed in §§ 226.145(a) or 226.146(a);

(2) Equipment or facility in which the operation is conducted is located off the lease or unit for engineering, economic, resource protection, or physical accessibility reasons; and

(3) Operations are conducted upstream of the FMP.

(c) The lessee must submit a request to the Superintendent, in writing, to obtain approval of royalty-free treatment of the volumes of oil and gas used. Such request must comply with the requirements set forth in § 226.151. If the Superintendent approves a request for royalty-free treatment under this section, the effective date of such approval will be the date the Superintendent received the lessee's request. If the Superintendent denies a request for royalty-free treatment under this section, the lessee must pay royalties on all volumes used.

(d) If equipment or a facility located on a particular lease treats oil or gas produced from the lease as well as oil or gas produced from properties that are not unitized with the lease, the lessee may only report as royalty-free that portion of the oil or gas used as fuel that is properly allocated to the share of production contributed by the lease or unit upon which the equipment or facility is located.

§ 226.149 Measurement or estimation of royalty-free volumes of oil or gas.

(a) The lessee must measure or estimate the volumes of royalty-free gas used upstream of the FMP.

(b) The lessee must measure the volume of gas that is removed from the product stream downstream of the FMP and used royalty-free pursuant to §§ 226.145 through 226.148.

(c) The lessee must measure the volume of oil that is used royalty-free pursuant to §§ 226.145 through 226.148. The lessee must also document the removal of such oil from the tank or pipeline.

(d) If the lessee removes oil or gas downstream of the FMP and it is used royalty-free pursuant to §§ 226.145 through 226.148, the lessee must notify the Superintendent, in writing, and obtain an approved FMP under § 226.86 to measure the production removed for use.

(e) The lessee must use the best available information when estimating gas volumes.

(f) The lessee must report each of the volumes required to be measured or estimated under this subpart to ONRR in accordance with §§ 226.45 and 226.87.

§ 226.150 Ownership of equipment and facilities.

The lessee is not required to own or lease the equipment or facility that uses oil or gas royalty-free under this subpart. The lessee is responsible for obtaining required authorizations, measuring and reporting production, and all other applicable requirements.

§ 226.151 Requesting approval of royalty-free treatment for volumes used.

The lessee must submit a request to the Superintendent, in writing, for approval of royalty-free use of production under this subpart. Such requests must include the following information:

(a) A complete description of the operation to be conducted, including the location of all equipment and facilities involved in the operation and the location of the FMP;

(b) The volumes of oil and gas the lessee expects will be used to conduct the operation and the method used to measure or estimate such volumes;

(c) If the volume of gas expected to be used is estimated, the basis for the estimate (*e.g.,* equipment manufacturer's published consumption or usage rates); and

(d) The proposed disposition of the oil and gas used (*e.g.,* whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or used in some other way).

Subpart M—Venting and Flaring

§ 226.152 General requirements.

(a) No venting or flaring of gas is permitted without the Superintendent's prior approval, except as defined in § 226.156.

(b) The lessee must notify the Superintendent by email or facsimile at least three business days prior to conducting approved venting or flaring operations.

(c) For purposes of this subpart, all flares or combustible devices must be equipped with an automatic ignition system.

§ 226.153 Gas-well gas.

Gas-well gas may not be vented or flared except where it is unavoidably lost under § 226.91(c).

§ 226.154 Oil-well gas.

Oil-well gas may be vented or flared in accordance with §§ 226.155, 226.156, and 226.157.

§ 226.155 Limitations on venting gas.

(a) The lessee must flare, rather than vent, any gas that is not captured, except when:

(1) Flaring the gas is technically infeasible, such as when the gas is not readily combustible, or the volumes are too small to flare;

(2) There are emergency conditions, as defined in § 226.156(d), and the loss of gas is uncontrollable, or venting is necessary for safety reasons;

(3) Gas is vented through normal operations of a natural gas-activated pneumatic controller or pump;

(4) Gas vapor is vented from a storage tank or other low-pressure production vessel, unless the Superintendent determined that recovery of the gas vapors is warranted;

(5) Gas is vented during downhole well maintenance or liquids unloading activities;

(6) Venting is necessary to allow the performance of non-routine facility and pipeline maintenance, such as when the lessee must occasionally blow-down and depressurize equipment to perform maintenance or repairs; or

(7) A release of gas is unavoidable under § 226.91(c) and flaring is prohibited by Federal law.

(b) Venting of gas that has an H_2S content of 100 ppm or greater is prohibited.

§ 225.156 Authorized venting and flaring of gas.

(a) *Initial production testing.* Gas flared during the initial production test of each completed interval in a well is royalty-free until one of the following occurs:

(1) The lessee obtains adequate reservoir information;

(2) It has been 30 calendar days since the beginning of the production test, unless the Superintendent approves a longer test period; or

(3) The lessee has flared 50 MMcf of gas.

(b) *Subsequent well tests.* Gas flared during well tests after the initial production test is royalty-free for a period not to exceed 24 hours unless the Superintendent approves or requires a longer test period.

(c) *Downhole well maintenance and liquids unloading.* Gas vented during downhole well maintenance and well purging is royalty-free for a period not to exceed 24 hours per event, provided that the requirements in paragraphs (c)(1) through (3) of this section are met. Gas vented from a plunger lift system or automated well control system is royalty-free, provided that the requirements in paragraphs (c)(1) and (2) of this section are met. For purposes of this section, ''well purging'' means blowing accumulated liquids out of a wellbore using reservoir gas pressure, whether manually or by an automatic control system that relies on real-time pressure or flow, times, or other well data, where gas is vented to the atmosphere. The term ''well purging'' does not apply to wells equipped with plunger lift systems.

(1) The lessee must minimize the loss of gas associated with downhole well maintenance and liquids unloading consistent with safe operations.

(2) For wells equipped with a plunger lift system or automated well control system, minimizing the loss of gas under paragraph (c)(1) of this section includes optimizing operation of the system to minimize gas losses to the maximum extent possible, consistent with removing liquids that would inhibit proper function of the well.

(3) For any liquids unloading by manual well purging, the lessee must ensure that the person conducting the well purging remains on-site throughout the operation so he can end the operation as soon as practical, thereby minimizing venting to the atmosphere to the maximum extent possible.

(d) *Emergencies.* (1) Gas vented or flared during an emergency is royalty-free for a period not to exceed 24 hours, unless the Superintendent determines that emergency conditions exist that necessitate venting or flaring for a longer period.

(2) For purposes of this subpart, an ''emergency'' is a temporary, infrequent, and unavoidable situation in which the loss of oil or gas is uncontrollable or necessary to avoid the risk of immediate and substantial adverse impacts on public health, safety, or the environment and that is not the result of lessee negligence or non-compliance.

(3) The following do not constitute emergencies for the purpose of royalty assessment:

(i) Failure to install appropriate equipment with sufficient capacity to accommodate the production conditions;

(ii) Failure to limit production when the production rate exceeds the capacity of the necessary equipment, pipeline, or gas plant or exceeds sales contract volumes of oil or gas;

(iii) Scheduled maintenance;

(iv) Situations caused by lessee negligence or non-compliance, including equipment failures; and

(v) Situations on a lease or unit that has experienced three or more emergencies within the past 30 days unless the Superintendent determines that the occurrence of such emergencies within the 30-day period could not have been anticipated and was beyond the lessee's control.

(4) The lessee must notify the Superintendent of all emergencies in writing, by email or facsimile, immediately upon discovery, but not later than the next calendar day.

(5) The lessee must estimate and report the volumes vented or flared beyond the timeframe specified in paragraph (c)(1) of this section within 45 calendar days of the date the emergency started.

§ 226.157 Measurement and reporting of volumes of gas vented or flared.

(a) The lessee must estimate or measure all volumes of oil and gas avoidably and unavoidably lost from wells, facilities, and equipment on a lease or unit and report such volumes to ONRR in accordance with §§ 226.45 and 226.87.

(b) The lessee may:

(1) Estimate the volume of gas vented or flared based on the results of a regularly performed GOR test and measured values for the volumes of oil production and gas sales to allow the Superintendent to independently verify the volume, rate, and heating value of the flared gas; or

(2) Measure the volume of the flared gas.

(c) The Superintendent may require the installation of additional measurement equipment whenever it is determined that the existing methods are inadequate to meet the purposes of this subpart.

(d) The lessee may combine gas from multiple leases or units for the purpose of venting or flaring at a common point but must allocate the quantities of the vented or flared gas to each lease or unit using a method the Superintendent approves.

Subpart N—Assessments and Penalties

Lease Management Assessments and Civil Penalties

§ 226.158 Remedies for violations of lease or permit terms and conditions, regulations, orders, and notices.

Violation of, or non-compliance with, the terms and conditions of any lease or permit, the regulations in this part, or orders and notices the Superintendent issues, may result in:

(a) Assessments;

(b) Civil penalties for each day such violation continues;

(c) Shut-in action; and

(d) Cancellation of the lease or permit and bond forfeiture.

§ 226.159 Immediate assessments for violations of certain operating regulations.

The Superintendent will issue immediate assessments upon discovery of the violations identified in Table 1. Assessments will be issued in the specified amounts per violation, per inspection. Imposition of these assessments does not preclude other appropriate enforcement action and civil penalties.

TABLE 1 TO § 226.159—VIOLATIONS SUBJECT TO AN IMMEDIATE ASSESSMENT

Violation	Assessment amount per violation ($)
1. Failure to post signs and install flags and wind indicators as required by § 226.70(d)(4) through (8)	$250
2. Failure to properly identify wells, tanks, and facilities as required by § 226.75	250
3. Failure to seal an appropriate valve on an oil storage tank as required by § 226.94	1,000
4. Failure to seal an appropriate valve or component on an oil metering system as required by § 226.95	1,000
5. Failure to properly measure oil before removal from storage for use on a different lease or unit as required by § 226.99(b)	1,000
6. Failure to retain records necessary to determine the quality and quantity of production as required by § 226.88	1,000
7. Missing or non-functioning FMP LACT system components as required by § 226.110	1,000
8. Missing or non-functioning FMP CMS components as required by § 226.111	1,000
9. Failure to meet the proving frequency requirements for an FMP as set forth in § 226.113	1,000
10. Failure to obtain the Superintendent's approval prior to using any oil measurement method other than tank gauging, LACT system, or CMS at an FMP as required by § 226.115	1,000
11. Failure to conduct new FMP orifice plate inspections as required by § 226.121(c)	1,000
12. Failure to conduct routine FMP orifice plate inspections as required by § 226.121(d)	1,000
13. Failure to conduct basic meter-tube inspections as required by § 226.121(g)	1,000
14. Failure to conduct detailed meter-tube inspections as required by § 226.121(h)	1,000
15. Failure to conduct an initial mechanical recorder verification as required by § 226.123(a)	1,000
16. Failure to conduct routine mechanical recorder verifications as required by § 226.123(b)	1,000
17. Failure to conduct an initial EGM system verification as a required by § 226.126(a)	1,000
18. Failure to conduct routine EGM system verifications as required by § 226.126(b)	1,000
19. Failure to take spot samples for FMPs as required by § 226.133	1,000
20. Failure to construct and maintain pits as required by § 226.77	2,500
21. Failure to install and maintain H_2S detection equipment as required by § 226.70(d)(2)	2,500

§ 226.160 Other assessments.

If a lessee fails to commence or perform an operation within five calendar days after the Superintendent orders such operation in writing, or such other time as may be specified in the order, the Superintendent may enter upon the lease and perform the operation, or have a third-party perform the operation, at the sole risk and expense of the lessee. The Superintendent will issue an assessment for the actual cost of performance plus an additional 25 percent of such amount for all operations performed by or through the Superintendent due to the lessee's non-compliance.

§ 226.161 Civil penalties with a period to correct.

(a) If a lessee or permittee violates the terms and conditions of the lease or permit, the regulations in this part, or orders and notices the Superintendent issues, the Superintendent may issue a NONC informing the lessee or permittee of the violation and specifying what actions, if any, must be taken to correct the non-compliance and avoid the assessment of civil penalties and cancellation of the lease or permit. Upon completion of the required corrective actions, the lessee must submit a Self-Certification for Correction of Lease Violations form to the Superintendent.

(b) If the violation is corrected within 20 calendar days of the NONC, or such longer period for correction specified in the NONC, the Superintendent will not assess a civil penalty or cancel the lease or permit but will consider the violations part of the lessee's or permittee's history of non-compliance for future penalty assessments.

(c) If the violation is not corrected within 20 calendar days of the NONC, or such longer period for correction specified in the NONC, the lessee or permittee will be liable for a civil penalty of up to $1,198 per violation for each day such violation continues, commencing with the date of the NONC.

(d) If the violation is not corrected within 40 calendar days of the notice, or such longer period for correction specified in the NONC, the lessee or permittee will be liable for a civil penalty of up to $11,995 per violation for each day such violation continues, commencing with the date of the NONC.

(e) If the Superintendent agrees to an extension of the time to take corrective action exceeding 20 calendar days, the date of the NONC will be deemed to be 20 calendar days prior to the end of the extended period for the purpose of civil penalty calculation.

(f) Any amount imposed and paid as assessments under § 226.159 will be deducted from penalties under this section.

§ 226.162 Civil penalties without a period to correct.

(a) The Superintendent may assess civil penalties for the violations identified in paragraphs (b) and (c) of this section without prior notice or an opportunity to correct the violation. The Superintendent will inform lessees, permittees, and other persons of violations resulting in civil penalties without a period to correct by issuing an ILCP identifying the violation and the amount of the civil penalty. For purposes of this section, civil penalties begin to accrue on the day the violation is committed.

(b) Any person is liable for a civil penalty of up to $23,989 per violation for each day such violation continues, if such person:

(1) Fails or refuses to permit the Superintendent's lawful entry or inspection pursuant to § 226.60; or

(2) Knowingly or willfully commences drilling, recompletion, or reentry operations, or causes surface disturbance preliminary thereto, without the Superintendent's prior approval in accordance with § 226.61.

(c) Any person is liable for a civil penalty of up to $59,973 per violation for each day such violation continues, if such person:

(1) Knowingly or willfully prepares, maintains, or submits false, inaccurate, or misleading reports, notices, affidavits, records, data, or other documents and information required by this part;

(2) Knowingly or willfully removes, transports, uses, or diverts any oil or gas from any lease or unit without valid legal authority to do so;

(3) Tampers with or bypasses any measurement device, component of a measurement device, or the measurement process;

(4) Purchases, accepts, sells, transports, or conveys oil or gas to any other person knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted from a lease or unit of the Osage Mineral Estate.

§ 226.163 Penalty amount.

(a) The Superintendent will determine the amount of the penalty to assess by considering:

(1) The severity of the violation; and

(2) The lessee's or permittee's history of non-compliance.

(b) The Superintendent may compromise or reduce a civil penalty assessed under this subpart.

§ 226.164 Shut-in actions.

(a) The Superintendent may take immediate shut-in action, without notice, when necessary for compliance; when operations are commenced or conducted without the required approval; or where continued operations could result in immediate adverse impacts on public health and safety, natural resources, the environment, production accountability, or royalty income.

(b) The Superintendent may take shut-in action in situations other than those identified in paragraph (a) of this section only after providing written notice to the lessee or permittee.

§ 226.165 Lease or permit cancellation.

(a) The Superintendent may issue a Notice of Cancellation for a lease or permit if a lessee or permittee:

(1) Is determined to have obtained the lease or permit by collusion, fraud, or misrepresentation;

(2) Fails to comply with the terms and conditions of the lease or permit, the regulations in this part, or other applicable laws;

(3) Fails to timely comply with, or respond to, an order or notice the Superintendent or ONRR issues;

(4) Fails to timely correct a violation under § 226.161;

(5) Fails to pay civil penalties in full on or before the date the Superintendent or ONRR specifies;

(6) Knowingly and willfully commits a violation that results in immediate adverse impacts on public health and safety, natural resources, or the environment, production accountability, or royalty income; or

(7) Has a history of non-compliance.

(b) The Notice of Cancellation will inform the lessee or permittee of the violation, set forth the reasons why cancellation is warranted, and specify what actions, if any, may be taken to avoid cancellation of the lease or permit and bond forfeiture.

(c) Cancellation of a lease or permit does not relieve the lessee or permittee of any continuing obligations under the lease, permit, or regulations in this part.

(d) Upon cancellation of a lease, the Osage Minerals Council may take immediate possession of the leased lands and all permanent improvements and surface equipment necessary for operation of the lease.

§ 226.166 Payment of assessments and civil penalties.

(a) The lessee or permittee must remit payment for civil penalties and immediate assessments set forth in this subpart within 10 business days of receipt of the notice of collection from the Superintendent by certified mail unless a different date is specified therein.

(b) Failure to timely pay civil penalties will result in the assessment of an interest charge on all unpaid or underpaid penalty and assessment amounts. Interest will be charged at the IRS underpayment rate pursuant to 26 U.S.C. 6621(a)(2), or such other rate as the Superintendent may prescribe. The IRS underpayment rate is posted quarterly and is available online at *https://www.irs.gov.* Interest will only be charged on the amount of the payment not received and for the number of days the payment is late.

(c) Payments made pursuant to subpart N of this part do not relieve the lessee or permittee of compliance with the terms and conditions of the lease or permit or the regulations in this part, nor do they relieve the lessee or permittee of liability for waste, surface damages, or any other damages that may be occasioned. A waiver, compromise, or reduction of any penalty must not be construed as precluding or limiting the imposition of penalties for any other violations or acts of non-compliance at that time or any other time.

Royalty Management Assessments and Civil Penalties

§ 226.167 Remedies for violations of lease or permit terms and conditions, regulations, orders, and notices.

Violation of the terms or conditions of a lease, permit, or the regulations in this part relating to royalty payment and reporting, production reporting, or non-compliance with any orders ONRR issues, may result in:

(a) Assessments;

(b) Civil penalties for each day such violation or non-compliance continues;

(c) Shut-in or cancellation of the lease and bond forfeiture under §§ 226.164 and 226.165; and

(d) The transfer of delinquent debts to the U.S. Department of Treasury for collection.

§ 226.168 Assessments for incorrect or late reports and failure to report.

(a) ONRR may issue assessments of up to $10 per day for each report it does not receive by the designated due date and for each report submitted that is incorrectly completed.

(b) ONRR will periodically establish the amount of the assessments imposed under paragraph (a) of this section based on its experience with costs and improper reporting. ONRR will publish notice of the assessment amount in the **Federal Register**.

§ 226.169 Assessments for failure to submit payment amount indicated on a form or bill document or to provide adequate information.

(a) ONRR may issue an assessment of up to $250 when the amount of a payment a reporter or payor submits is not equivalent in amount to the total of individual line items on the associated form or bill document, unless ONRR authorized the difference in amount.

(b) ONRR may issue an assessment of up to $250 for each payment a reporter or payor submits that cannot be automatically applied to the associated form or bill document because the reporter or payor submitted inadequate or erroneous information.

(c) For purposes of this section, the term ''applicable forms'' include Form ONRR–2014, Form ONRR–4054, and any other forms ONRR requires under this part.

(d) For purposes of this section, the term ''bill document'' means any invoice that ONRR issues for assessments, late-payment interest charges, or other amounts owed. A payment document is defined as a check or wire transfer message.

(e) For purposes of this section, ''inadequate or erroneous information'' is defined as an:

(1) Absent or incorrect payor-assigned document number the reporter or payor is required to identify in Block 4 on Form ONRR–2014 (document 4 number), or the reuse of the same incorrect payor-assigned document 4 number in a subsequent reporting period;

(2) Absent or incorrect bill document invoice number (to include the three-character alpha prefix and the nine-digit number) or the payor-assigned document 4 number the reporter or payor is required to be identify on the associated payment document, or reuse of the same incorrect payor-assigned document 4 number in a subsequent reporting period;

(3) Absent or incorrect name of the administering BIA agency or office or the Tribe name on payment documents remitted. If the payment is made by EFT, the reporter or payor must identify the Tribe on the EFT message by a pre-established five-digit code;

(4) Absent or incorrect ONRR-assigned payor code on a payment document; or

(5) Absent or incorrect identification on a payment document.

(f) ONRR will periodically establish the amount of the assessment to be imposed under paragraphs (a) and (b) of this section. The amount of the assessment for each violation will be based on ONRR's experience with costs and improper reporting. ONRR will publish notice of the assessment amount in the **Federal Register**.

§ 226.170 Civil penalties with a period to correct.

(a) If a reporter or payor violates the terms and conditions of the lease, the regulations in this part or any order relating to royalty and production reporting and payment requirements, ONRR may issue a NONC informing the reporter or payor of the violation and specifying what actions, if any, must be taken to correct the violation and avoid the assessment of civil penalties.

(b) If the violation is corrected within 20 calendar days of the NONC, or such longer period for correction specified in the NONC, ONRR will not assess a civil penalty or request that the Superintendent shut-in or cancel the lease or permit but will consider the violations part of the reporter's or payor's history of non-compliance for future penalty assessments.

(c) If the violation is not corrected within 20 calendar days after the date on which the NONC is served, or within 20 days following the expiration of any longer period for correction specified in the NONC, ONRR may issue an FCCP.

(1) The FCCP will state the amount of the penalty. The penalty will:

(i) Begin to run on the day the NONC is served; and

(ii) Continue to accrue for each violation identified in the NONC until it is corrected.

(2) The penalty may be up to $1,368 per day for each violation identified in the NONC that has not been corrected.

(d) If the violation is not corrected within 40 calendar days from the date the NONC is served, or within 20 calendar days following the expiration of any longer correction period specified in the NONC, the reporter or payor will be liable for a penalty of up to $13,693 per day for each day the violation identified in the NONC that has not been corrected. The increased penalty will:

(1) Begin to run on the 40th day after the day the NONC was served or on the 20th day after the expiration of any longer correction period in the NONC; and

(2) Continue to accrue for each violation identified in the NONC until it is corrected.

§ 226.171 Civil penalties without a period to correct.

(a) ONRR may assess a penalty for a violation identified in paragraphs (b) and (c) of this section without prior notice or an opportunity to correct the violation. ONRR will inform reporters and payors of violations without a period to correct by issuing an ILCP explaining the violation and the amount of the civil penalty. The penalty will begin to run on the day the violation is committed.

(b) A reporter or payor is liable for a civil penalty of up to $27,384 per violation for each day the violation continues if they:

(1) Fail or refuse to permit lawful entry, inspection, or audit, including refusal to keep, maintain, or produce documents; or

(2) Knowingly or willfully fail to make any royalty payment by the date specified in the lease, regulations in this part, or any applicable order.

(c) A reporter or payor is liable for a civil penalty up to $68,462 per violation for each day the violation continues if they knowingly or willfully prepare, maintain, or submit false, inaccurate, or misleading reports, notices, affidavits, records, data, or other information to ONRR.

(d) ONRR may use any information as evidence that a reporter or payor knowingly or willfully committed a violation including, but not limited to:

(1) Any acts, or failures to act, by a reporter's or payor's employee or agent;

(2) An email indicating the reporter's or payor's concurrence with an issue;

(3) An order that the reporter or payor failed to appeal an order, NONC, or ILCP for which no further appeal is available; and

(4) Any oral or written communication that identifies a violation that the reporter or payor:

(i) Acknowledges as true and fails to correct;

(ii) Fails to appeal, or cannot further appeal, and fails to correct; or

(iii) Corrects, but the reporter or payor subsequently commits the same violation.

§ 226.172 Penalty amount.

(a) ONRR will determine the amount of the penalty to assess by considering the:

(1) Severity of the violation;

(2) History of non-compliance; and

(3) Size of the reporter's or payor's business. To determine business size, ONRR may consider the number of employees in the reporter's or payor's company, parent company or companies, and any subsidiaries or contractors.

(b) ONRR will not consider the royalty consequence of the underlying violation when determining the amount of the civil penalty for a violation under §§ 226.170, 226.171(b)(1), and 226.171(c).

(c) FCCP and ILCP assessment matrices and adjustments thereto are posted on ONRR's website.

(d) Penalties ONRR assesses under this subpart are in addition to interest owed on any underlying payments or unpaid debts and are supplemental to, not in derogation of, any other penalties or assessments for non-compliance set forth in this part or other applicable laws and regulations.

(e) ONRR may compromise or reduce a civil penalty assessed under this subpart.

§ 226.173 Payment of assessments and civil penalties.

(a) The reporter or payor must remit payment for the civil penalties and assessments set forth in §§ 226.168 through 226.171 on or before the due date identified in the bill accompanying the FCCP or ILCP.

(b) Failure to timely pay civil penalties and assessments will result in the reporter or payor owing late-payment interest on all unpaid or underpaid penalty and assessment amounts. Interest will be charged in accordance with § 226.166(b) beginning on the day the payment was due and continuing until all debts are paid in full.

§ 226.174 Collection of unpaid civil penalties.

If a reporter or payor fails to pay a civil penalty amount on or before the date it is due, ONRR may use all available means to collect the penalty including, but not limited to:

(a) For an amount owed by a lessee, requiring the lease surety to pay the penalty;

(b) Deducting the amount of the penalty from any sum the United States may owe the reporter or payor; or

(c) Referring the debt to the U.S. Department of the Treasury (Treasury) for collection in accordance with § 226.175.

§ 226.175 Debt collection and administrative offset.

(a) ONRR will transfer any past due, legally enforceable non-tax debt to Treasury within 180 days from the date the debt becomes past due so that Treasury may take appropriate action to collect the debt or terminate the collection action 26 U.S.C. 6402(d)(1)–(2); 31 U.S.C. 3711, 3716, and 3720A; Federal Claims Collection Standards (31 CFR parts 900 through 904); and 31 CFR 285.2 and 285.5.

(b) If ONRR determines that a person owes, or may owe, a legally enforceable debt to ONRR, it will send a written notice to the debtor advising that ONRR intends to refer the debt to Treasury. The notice will inform the debtor of the:

(1) Amount, nature, and basis of the debt;

(2) Methods of offset that ONRR or Treasury may use;

(3) Opportunity to inspect and copy Agency records related to the debt;

(4) Opportunity to enter into a written agreement with ONRR to repay the debt;

(5) ONRR's policy regarding interest and administrative costs, including a statement that ONRR will make such assessments unless it determines otherwise under the criteria of the Federal Claims Collection Standards and this part;

(6) Date by which payment must be remitted to avoid additional late charges and enforced collection; and

(7) Name, address, and phone number of an ONRR representative who is available to discuss the debt.

(c) Debtors that receive a notice issued pursuant to paragraph (b) of this section may not appeal unless the notice specifically provides for such opportunity because the debtor did not previously receive a notice of the order, decision on appeal, or any other notice or decision that is the basis of the debt that ONRR intends to refer to Treasury and for which the debtor may be liable in whole or in part under applicable law. Debtors may not dispute matters related to delinquent debts that were the subject of a final order or appeal decision of which they were the recipient or a party thereto and that are the basis of the delinquent debt. The requirements under this paragraph apply whether the debtor appealed the order, demand, NONC, or assessment.

(d) ONRR will issue an initial assessment of $436 for administrative costs incurred because of a debtor's failure to pay a delinquent debt. ONRR will publish notice of any increases in administrative costs in the **Federal Register**. ONRR may also assess an additional $436 for administrative costs that continue to accrue during any appeal process if:

(1) The notice issued under paragraph (b) of this section grants the right to appeal and the debtor exercises that right; and

(2) The appeal is denied and ONRR refers the delinquent debt to Treasury.

(e) ONRR will apply a partial or installment payment made on a delinquent debt sent to Treasury in the following order: outstanding penalty assessments, administrative costs, accrued interest, and outstanding debt principal.

(f) The Director of ONRR may waive collection of all or part of the administrative costs under paragraph (d) of this section if they determine that collection of this charge would be against equity and good conscience or the Federal Government's best interest. The Director's decision to collect or waive administrative costs is the final decision for the Department and is not subject to administrative review.

(g) The Director of ONRR may recommend that the Superintendent revoke a debtor's ability to engage in the leasing of any trust or restricted lands or the granting of easements, permits, or rights-of-way if the debtor inexcusably or willfully fails to pay a debt. Any such recommendation will remain in effect until such time as the debt is paid in full or otherwise resolved to ONRR's satisfaction.

(h) ONRR may refer any past due, legally enforceable debt to Treasury to collect through administrative offset or tax refund offset at least 60 calendar days after it issues notice under paragraph (b) of this section if the debt is at least $250 or such other base amount as may be established by Treasury.

(i) ONRR may refer debts reduced to judgment to Treasury for tax refund offset at any time.

Criminal Penalties

§ 226.176 Penalties for filing fraudulent reports.

Any person who knowingly and willfully files fraudulent reports or information under the regulations in this part is subject to criminal penalties under 18 U.S.C. 1001.

Subpart O—Appeals

Appeals of BIA Decisions

§ 226.177 Procedure for filing an administrative appeal of a decision, order, or notice of the Superintendent.

(a) Any party adversely affected by a decision, order, or notice the Superintendent issues by virtue of the regulations in this part may appeal pursuant to 25 CFR part 2.

(b) If an appeal is not timely filed with the Regional Director under 25 CFR part 2 and subsequently with the IBIA under 43 CFR part 4, subpart D (where required):

(1) The subject decision, order, or notice will be final for the Department; and

(2) The affected party will be barred from contesting the validity or merits of the decision, order, or notice in subsequent administrative or judicial proceedings due to failure to exhaust administrative remedies.

Appeals of ONRR Decisions

§ 226.178 Procedures for filing and administrative appeal of an order from ONRR.

(a) Any party adversely affected by an order ONRR issues by virtue of the regulations in this part may appeal to the Director of ONRR as set forth in this section.

(b) For purposes of this section, the term ''order'' means any document ONRR issues that contains language mandating or directing the recipient to report, compute, or pay royalties or other obligations; report production; or provide any other information.

(1) An order includes, but is not limited to:

(i) An Order to Pay or Order to Perform a Restructured Accounting;

(ii) A decision from ONRR denying a lessee's, reporter's, or payor's written request and that imposes an obligation on the lessee, reporter, or payor (a denial); and

(iii) A NONC, FCCP, or ILCP.

(2) An order does not include:

(i) A non-binding request, information, or guidance, such as a policy determination or guidance on how to report or pay, including a valuation determination, unless it contains language indicating that an action is mandatory or expressly orders the recipient(s) to take a certain action;

(ii) A subpoena;

(iii) An order that ONRR issues to a refiner or other person involved in disposition of royalty taken in-kind;

(iv) A ''Dear Lessee,'' ''Dear Payor,'' or ''Dear Reporter'' letter, unless it explicitly includes the right to appeal; or

(v) Any other correspondence from ONRR that does not include the right to appeal.

(c) A lessee or designee may appeal an order to the Director of ONRR by filing a Notice of Appeal in the office of the official that issued the order within 30 calendar days from the date the order was received. If a designee is filing an appeal, they must concurrently serve the Notice of Appeal on all lessees for the lease(s) identified in the order by certified mail—return receipt requested. Within the same 30-day period, the lessee or designee must file a Statement of Reasons setting forth any factual and legal arguments justifying reversal or modification of the order. No extension of time will be granted for filing the Notice of Appeal.

(d) A lessee may join an appeal filed by a designee within 30 calendar days from the date the lessee receives the Notice of Appeal by filing a Notice of Joinder with the office of the official that issued the order. If a lessee joins an appeal, they are deemed to appeal the order jointly with the designee, but the designee must fulfill all requirements imposed on appellants under this section and 43 CFR part 4, subpart E. Lessees may not file pleadings separately from the designee.

(1) If a lessee does not appeal, or join the designee's appeal, the designee's actions with respect to the appeal and any decisions therein are binding on the lessee.

(2) If a designee decides to discontinue participation in an appeal, they must serve written notice at least 30 calendar days before the next pleading is due. The notice must be served on:

(i) All lessees who joined the appeal under this section;

(ii) The office or officer with whom subsequent pleadings must be filed; and

(iii) All other parties to the appeal.

(e) Any party adversely affected by a decision the Director of ONRR issues under this section may appeal the decision to the IBLA pursuant to 43 CFR part 4, subpart E.

(f) If an order is neither paid, nor appealed to the Director of ONRR under this section and, subsequently, to the IBLA under 43 CFR part 4, subpart E:

(i) The order is the final decision of the Department; and

(ii) The affected party will be barred from contesting the validity or merits of the order in subsequent administrative or judicial proceedings, including enforcement proceedings.

§ 226.179 Suspension of compliance with an ONRR order.

(a) For purposes of this subpart, ''ONRR-specified surety instrument'' means an ONRR-specified administrative appeal bond, an ONRR-specified irrevocable letter of credit, or a financial institution book-entry certificate of deposit.

(b) Subject to paragraph (d) of this section, if an affected party appeals an order regarding the payment or reporting of royalties and other payments due from leases of the Osage Mineral Estate:

(1) If the amount under appeal is less than $1,000, or does not require payment, the appellant's obligation to comply with the order is suspended while the appeal is pending. ONRR will use the performance bond posted with the BIA as collateral for the obligation.

(2) If the amount under appeal is $1,000 of more, ONRR will suspend the appellant's obligation to comply with the order if they submit an ONRR-specified surety instrument under this subpart within 60 calendar days of the date they receive the order or Notice of Order.

(c) Nothing in this subpart prohibits an appellant from paying any demanded amount or otherwise complying with any other requirement pending resolution of their appeal. Voluntarily paying any demanded amount or otherwise complying with any other requirement when suspension of an order is available under the regulations does not create a final agency action subject to judicial review under 5 U.S.C. 704.

(d) Regardless of the amount under appeal, ONRR may inform an appellant that it will not suspend their obligation to comply with the order under paragraph (a) of this section because suspension would harm the interests of the United States or Osage Nation.

§ 226.180 Requirements for posting a bond or other surety on behalf of an appellant.

Any person, including a designee, payor, or affiliate, may post a bond or surety instrument under this subpart on behalf of an appellant. If you assume an appellant's responsibility to post a bond or other surety instrument, you:

(a) Must notify ONRR in writing that you are assuming the appellant's responsibility under this subpart;

(b) May not assert that you are not otherwise liable for royalties or other payments under the lease, or any other theory, as a defense if ONRR collects your bond or other surety instrument; and

(c) May end your voluntarily assumed responsibility for posting a bond or other surety instrument only after the appellant pays or posts a bond or other surety instrument.

§ 226.181 Suspension of the obligation to comply with an ONRR order due to judicial review in federal court.

(a) If an appellant seeks judicial review of an IBLA decision or another final action of the Department of the Interior regarding an ONRR order, ONRR will suspend the appellant's obligation to comply with that order pending judicial review if they continue to meet the requirements of this subpart.

(b) Notwithstanding paragraph (a) of this section, ONRR may decide that it will not suspend an appellant's obligation to comply with an order. ONRR will notify the appellant in writing of such decision and the reasons for it.

§ 226.182 ONRR's collection of bonds and other surety instruments.

(a) This section applies to you if you maintain a bond or an ONRR-specified surety instrument on your own behalf or on another person's behalf for an appeal of an order under this subpart.

(b) ONRR may initiate collection of your bond or other surety instrument if:

(1) The Director of ONRR decides the appeal adversely to you and you do not pay the amount due or appeal the decision further to the IBLA under 43 CFR part 4, subpart E;

(2) The IBLA, Director of the Office of Hearings and Appeals, an Assistant Secretary, or the Secretary decides the appeal adversely to you and you do not pay the amount due or pursue judicial review within 90 calendar days of the decision;

(3) A court of competent jurisdiction issues a final non-appealable decision adverse to you and you do not pay the amount due within 30 calendar days of the decision;

(4) You do not increase the amount of your bond or other surety instrument as required under § 226.185(c), or otherwise fail to maintain an adequate surety instrument in effect, and you do not pay the amount due under the ONRR order within 30 calendar days of receipt of the notice from ONRR under § 226.185(c); or

(5) The obligation to comply with an order or decision is not suspended and you do not pay the amount required under the order or decision.

§ 226.183 ONRR bond-approving officer's determination of surety amount not subject to appeal.

Any decision regarding the amount of the surety due under this subpart is final and not subject to appeal.

§ 226.184 Standards for ONRR-specified surety instruments.

(a) An ONRR-specified surety instrument must be in a form identified in ONRR's instructions. ONRR will provide written information and standards forms for ONRR-specified surety instrument requirements.

(b) ONRR will use a bank-rating service to determine whether a financial institution has an acceptable rating to provide a surety instrument adequate to indemnify the lessor from loss or damage.

(1) Administrative appeal bonds must be issued by a qualified surety company that Treasury approved.

(2) Irrevocable letters of credit or certificates of deposit must be from a financial institution acceptable to ONRR with a minimum one-year period of coverage subject to automatic renewal up to five years.

§ 226.185 ONRR's determination of bond or surety instrument amount.

(a) The ONRR bond-approving officer may approve an appellant's surety if they determine that the amount is adequate to guarantee payment. The amount of the appellant's surety may vary depending on the form of the surety and how long the surety is effective.

(b) The amount of the ONRR-specified surety instrument must include the principal amount owed under the order plus any accrued interest ONRR determines is owed plus projected interest for a one-year period.

(c) If an appeal is not decided within one year from the date of filing, the appellant must increase the surety amount to cover additional estimated interest for another one-year period. The appellant must continue to increase the surety amount annually on the date of filing for the duration of the appeal. ONRR will determine the additional estimated interest and notify the appellant of the amount so it can amend your surety instrument.

(d) The appellant may submit a single surety instrument that covers multiple appeals. The appellant may change the instrument to add new amounts under appeal or remove amounts that have been adjudicated in their favor or that they have paid if they:

(1) Amend the single surety instrument annually on the date they filed their first appeal; and

(2) Submit a separate surety instrument for new amounts under appeal until they amend the instrument to cover the new appeals.

Appendix A to Part 226—Table of Atmospheric Pressures

Elevation (ft msl)	Atmos. pressure (psi)	Elevation (ft msl)	Atmos. pressure (psi)	Elevation (ft msl)	Atmos. pressure (psi)
0	14.70	**4,000**	12.70	**8,000**	10.92
100	14.64	4,100	12.65	8,100	10.88
200	14.59	4,200	12.60	8,200	10.84
300	14.54	4,300	12.56	8,300	10.80
400	14.49	4,400	12.51	8,400	10.76
500	14.43	4,500	12.46	8,500	10.72
600	14.38	4,600	12.42	8,600	10.68
700	14.33	4,700	12.37	8,700	10.63
800	14.28	4,800	12.32	8,800	10.59
900	14.23	4,900	12.28	8,900	10.55
1,000	14.17	**5,000**	12.23	**9,000**	10.51
1,100	14.12	5,100	12.19	9,100	10.47
1,200	14.07	5,200	12.14	9,200	10.43
1,300	14.02	5,300	12.10	9,300	10.39
1,400	13.97	5,400	12.05	9,400	10.35

Elevation (ft msl)	Atmos. pressure (psi)	Elevation (ft msl)	Atmos. pressure (psi)	Elevation (ft msl)	Atmos. pressure (psi)
1,500	13.92	5,500	12.01	9,500	10.31
1,600	13.87	5,600	11.96	9,600	10.27
1,700	13.82	5,700	11.92	9,700	10.23
1,800	13.77	5,800	11.87	9,800	10.19
1,900	13.72	5,900	11.83	9,900	10.15
2,000	13.67	**6,000**	11.78	**10,000**	10.12
2,100	13.62	6,100	11.74	10,100	10.08
2,200	13.57	6,200	11.69	10,200	10.04
2,300	13.52	6,300	11.65	10,300	10.00
2,400	13.47	6,400	11.61	10,400	9.96
2,500	13.42	6,500	11.56	10,500	9.92
2,600	13.37	6,600	11.52	10,600	9.88
2,700	13.32	6,700	11.48	10,700	9.84
2,800	13.27	6,800	11.43	10,800	9.81
2,900	13.22	6,900	11.39	10,900	9.77
3,000	13.17	**7,000**	11.35	**11,000**	9.73
3,100	13.13	7,100	11.30	11,100	9.69
3,200	13.08	7,200	11.26	11,200	9.65
3,300	13.03	7,300	11.22	11,300	9.62
3,400	12.98	7,400	11.18	11,400	9.58
3,500	12.93	7,500	11.13	11,500	9.54
3,600	12.89	7,600	11.09	11,600	9.50
3,700	12.84	7,700	11.05	11,700	9.47
3,800	12.79	7,800	11.01	11,800	9.43
3,900	12.74	7,900	10.97	11,900	9.39

Calculated as:

$Palm = 14.696 \times (1 \times 0.00000686E)^{525577}$

From: U.S. Standard Atmosphere, 1976, U.S. Government Printing Office, Washington, DC 1976.

Bryan Newland,

Assistant Secretary—Indian Affairs.

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