DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3160 and 3170

[15X.LLWO300000.L13100000.NB0000]

RIN 1004–AE17

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas

AGENCY: Bureau of Land Management, Interior.

ACTION: Proposed rule.

SUMMARY: This proposed rule would revise and replace Onshore Oil and Gas Order No. 5 (Order 5) with a new regulation that would be codified in the Code of Federal Regulations. This proposed rule would establish the minimum standards for accurate measurement and proper reporting of all gas removed or sold from Federal and Indian leases (except the Osage Tribe), units, unit participating areas, and areas subject to communitization agreements, by providing a system for production accountability by operators, lessees, purchasers, and transporters. This proposed rule would include requirements for the hardware and software related to approved metering equipment, overall measurement performance standards, and reporting and record keeping. The proposed rule would identify certain specific acts of noncompliance that would result in an immediate assessment and would provide a process for the BLM to consider variances from the requirements of this proposed rule.

DATES: Send your comments on this proposed rule to the BLM on or before December 14, 2015. The BLM is not obligated to consider any comments received after the above date in making its decision on the final rule.

If you wish to comment on the information collection requirements in this proposed rule, please note that the Office of Management and Budget (OMB) is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by November 12, 2015.

ADDRESSES: *Mail:* U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134 LM, 1849 C St. NW., Washington, DC 20240, Attention: 1004–AE17. *Personal or messenger delivery:* 20 M Street SE., Room 2134LM, Washington, DC 20003. *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions at this Web site.

Comments on the information collection burdens: *Fax:* Office of Management and Budget (OMB), Office of Information and Regulatory Affairs, Desk Officer for the Department of the Interior, fax 202–395–5806. *Electronic mail: OIRA_Submission@omb.eop.gov*. Please indicate ''Attention: OMB Control Number 1004–XXXX,'' regardless of the method used to submit comments on the information collection burdens. If you submit comments on the information collection burdens, you should provide the BLM with a copy of your comments, at one of the addresses shown above, so that we can summarize all written comments and address them in the final rule preamble.

FOR FURTHER INFORMATION CONTACT: Richard Estabrook, petroleum engineer, Division of Fluid Minerals, 707–468–4052. For questions relating to regulatory process issues, please contact Faith Bremner at 202–912–7441. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact the above individual during normal business hours. FIRS is available 24 hours a day, 7 days a week to leave a message or question with the above individual. You will receive a reply during normal business hours. The information collection request for this proposed rule has been submitted to OMB for review under 44 U.S.C. 3507(d). A copy of the request can be obtained from the BLM by electronic mail request to Jennifer Spencer at *j35spenc@blm.gov* or by telephone request to 202–912–7146. You may also review the information collection request online at *http://www.reginfo.gov/public/do/PRAMain*.

SUPPLEMENTARY INFORMATION:

Executive Summary

The BLM's regulations that govern how gas produced from onshore Federal and Indian leases is measured and accounted for are more than 25 years old and need to be updated to be consistent with modern industry practices. Federal laws, metering technology, and industry standards have changed significantly since the BLM adopted Order 5 in 1989. In a number of separate reports, three outside independent entities—the Interior Secretary's Subcommittee on Royalty Management (the Subcommittee) in 2007, the Department of the Interior's Office of the Inspector General (OIG) in 2009, and the Government Accountability Office (GAO) in 2010, 2011, 2013, and 2015—have repeatedly recommended that the BLM evaluate its gas measurement guidance and regulations to ensure that operators pay the proper royalties. Specifically, these groups found that Interior needed to provide Department-wide guidance on measurement technologies and processes not addressed in current regulations, including guidance on the process for approving variances in instances when technologies or processes are not addressed in the future. As explained below, the provisions of this proposed rule respond to these recommendations by the Subcommittee, the GAO, and the OIG.

The BLM's oil and gas program is one of the most important mineral leasing programs in the Federal Government. Domestic production from Federal and Indian onshore oil and gas leases accounts for approximately 10 percent of the nation's natural gas supply and 7 percent of its oil. In Fiscal Year (FY) 2014, the Office of Natural Resources Revenue (ONRR) reported that onshore Federal oil and gas leases produced about 148 million barrels of oil, 2.48 trillion cubic feet of natural gas, and 2.9 billion gallons of natural gas liquids, with a market value of more than $27 billion and generating royalties of almost $3.1 billion. Nearly half of these revenues are distributed to the States in which the leases are located. Leases on Tribal and Indian lands produced 56 million barrels of oil, 240 billion cubic feet of natural gas, 182 million gallons of natural gas liquids, with a market value of almost $6 billion and generating royalties of over $1 billion that were all distributed to the applicable tribes and individual allottee owners. Despite the magnitude of this production, the BLM's rules governing how that gas is measured and accounted for are more than 25 years old and need to be updated and strengthened. Federal laws, technology, and industry standards have all changed significantly in that time.

The Secretary of the Interior has the authority under various Federal and Indian mineral leasing laws to manage oil and gas operations. The Secretary has delegated this authority to the BLM, which issued onshore oil and gas operating regulations codified at 43 CFR part 3160. Over the years, the BLM issued seven Onshore Oil and Gas Orders that deal with different aspects of oil and gas production. These Orders were published in the **Federal Register**, both for public comment and in final form, but they do not appear in the Code of Federal Regulations (CFR). This proposed rule would replace Order 5, Measurement of Gas, with a new regulation that would be codified in the CFR.

The discussion that immediately follows summarizes and briefly explains the most significant changes proposed in this rule. Each of these will be discussed more fully in the section-by-section analysis below. For that reason, references to specific section and paragraph numbers are omitted in the body of this discussion.

1. Determining and Reporting Heating Value and Relative Density (§§ 3175.110 through 3175.126)

The most significant proposed change would be new requirements for determining and reporting the heating value and relative density of all gas produced. Royalties on gas are calculated by multiplying the volume of the gas removed or sold from the lease (generally expressed in thousands of standard cubic feet (Mcf)) by the heating value of the gas in British thermal units (Btu) per unit volume, the value of the gas (expressed in dollars per million Btu (MMBtu), and the fixed royalty rate. So a 10 percent error in the reported heating value would result in the same error in royalty as a 10 percent error in volume measurement. Relative density, which is a measure of the average mass of the molecules flowing through the meter, is used in the calculation of flow rate and volume. Under the flow equation, a 10 percent error in relative density would result in a 5 percent error in the volume calculation. Both heating value and relative density are determined from the same gas sample.

Order 5 requires a determination of heating value only once per year. Federal and Indian onshore gas producers can then use that value in the royalty calculations for an entire year. There are currently no requirements for determining relative density. Existing regulations do not have standards for how gas samples used in determining heating value and relative density should be taken and analyzed to avoid biasing the results. In addition, existing regulations do not prescribe when and how operators should report the results to the BLM.

In response to a Subcommittee recommendation that the BLM determine the potential heating-value variability of produced natural gas and estimate its implications for royalty payments, the BLM conducted a study which found significant sample-to-sample variability in heating value and relative density at many of the 180 gas facility measurement points (FMP) it analyzed. The ''BLM Gas Variability Study Final Report,'' May 21, 2010, used 1,895 gas analyses gathered from 65 formations. In one example, the study found that heating values measured from samples taken at a gas meter in the Anderson Coal formation in the Powder River Basin varied ±31.41 percent, while relative density varied ±19.98 percent. In multiple samples collected at another gas meter in the same formation, heating values varied by only ±2.58 percent, while relative density varied by ±3.53 percent (p. 25). Overall, the uncertainty in heating value and relative density in this study was ±5.09 percent, which, across the board, could amount to ±$127 million in royalty based on 2008 total onshore Federal and Indian royalty payments of about $2.5 billion (p. 16). Uncertainty is a statistical range of error that indicates the risk of measurement error.

The study concluded that heating value variability is unique to each gas meter and is not related to reservoir type, production type, age of the well, richness of the gas, flowing temperature, flow rate, or a number of other factors that were included in the study (p. 17). The study also concluded that more frequent sampling increases the accuracy of average annual heating value determinations (p. 11).

This proposed rule would strengthen the BLM's regulations on measuring heating value and relative density by requiring operators to sample all meters more frequently than currently required under Order 5, except marginal-volume meters (measuring 15 Mcf/day or less) whose sampling frequency (*i.e.,* annually) would not change. Low-volume FMPs (measuring more than 15 Mcf/day, but less than or equal to 100 Mcf/day) would have to be sampled every 6 months; high-volume FMPs (measuring more than 100 Mcf/day, but less than or equal to 1,000 Mcf/day) would initially be sampled every 3 months; very-high-volume FMPs (measuring more than 1,000 Mcf/day) would initially be sampled every month.

The proposed rule would also set new average annual heating value uncertainty standards of ±2 percent for high-volume FMPs and ±1 percent for very-high-volume FMPs. The BLM established these uncertainty thresholds by determining the uncertainty at which the cost of compliance equals the risk of royalty underpayment or overpayment.

In developing this proposed rule, the BLM realized that a fixed sampling frequency may not achieve a consistent level of uncertainty in heating value for high-volume and very-high-volume meters. For example, a 3-month sampling frequency may not adequately reduce average annual heating value uncertainty in a meter which has exhibited a high degree of variability in the past. On the other hand, a 3-month sampling frequency may be excessive for a meter which has very consistent heating values from one sample to the next. If a high- or very-high-volume FMP did not meet these proposed heating-value uncertainty limits, the BLM would adjust the sampling frequency at that FMP until the heating value meets the proposed uncertainty standards. If a high- or very-high-volume FMP continues to not meet the uncertainty standards, the BLM could require the installation of composite samplers or on-line gas chromatographs, which automatically sample gas at frequent intervals.

In addition to prescribing uncertainty standards and more frequent sampling, this proposed rule also would improve measurement and reporting of heating values and relative density by setting standards for gas sampling and analysis. These proposed standards would specify sampling locations and methods, analysis methods, and the minimum number of components that would have to be analyzed. The proposed standards would also set requirements for how and when operators report the results to the BLM and ONRR, and would define the effective date of the heating value and relative density that is determined from the sample.

2. Meter Inspections (§ 3175.80)

This proposed rule would require operators to periodically inspect the insides of meter tubes for pitting, scaling, and the buildup of foreign substances, which could bias measurement. Existing regulations do not address this issue. Visual meter tube inspections would be required once every 5 years at low-volume FMPs, once every 2 years at high-volume FMPs, and yearly at very-high-volume FMPs. The BLM could increase this frequency and require a detailed meter-tube inspection of a low-volume FMP meter if the visual inspection identifies any issues or if the meter tube operates in adverse conditions, such as with corrosive or erosive gas flow. A detailed meter-tube inspection involves removing or disassembling the meter run. Detailed meter-tube inspections would be required once every 10 years at high-volume FMPs and once every 5 years at very-high-volume FMPs. Operators would have to replace meter tubes that no longer meet the requirements proposed in this rule.

3. Meter Verification or Calibration (§§ 3175.92 and 3175.102)

The proposed rule would increase routine meter verification or calibration requirements for metering equipment at very-high-volume FMPs and decrease the requirements at marginal-volume FMPs. Verification frequency would be unchanged for high-volume FMPs, as well as for low-volume FMPs that use mechanical recorder systems. Verification frequency would be decreased for low-volume FMPs using electronic gas measurement (EGM) systems.

Under Order 5, all meters must undergo routine verification every 3 months, regardless of the throughput volume. This proposed rule would require monthly verification for very-high-volume FMPs, while the verification requirement for high-volume FMPs would remain at every 3 months. The rationale for this proposed change is that the consequences of measurement and royalty-calculation errors at very-high-volume FMPs are more serious than they are at high-, low-, and marginal-volume FMPs. The schedule for routine verification for low- and marginal-volume FMPs that use EGM systems would decrease to every 6 months for low-volume FMPs and yearly for marginal-volume FMPs.

The routine verification schedule for low- and marginal-volume FMPs that use mechanical chart recorders would be every 3 months for low-volume FMPs and every 6 months for marginal-volume FMPs. The proposed rule would restrict the use of mechanical chart recorders to low- and marginal-volume FMPs because the accuracy and performance of mechanical chart recorders is not defined well enough for the BLM to quantify overall measurement uncertainty. Between 80 percent and 90 percent of gas meters at Federal onshore and Indian FMPs use EGM systems.

4. Requirements for EGM Systems (§§ 3175.30, 3175.100 through 3175.104, and 3175.130 through 3175.144)

Although industry has used EGM systems for about 30 years, Order 5 does not address them. Instead, the BLM has regulated their use through statewide Notices to Lessees (NTLs), which do not address many aspects unique to EGMs, such as volume calculation and data-gathering and retention requirements. This proposed rule includes many of the existing NTL requirements for EGM systems and adds some new ones relating to on-site information, gauge lines, verification, test equipment, calculations, and information generated and retained by the EGM systems. The proposed rule would make a significant change in those requirements by revising the maximum flow-rate uncertainty that is currently allowed under existing statewide NTLs. Currently, flow-rate equipment at FMPs that measure more than 100 Mcf/day is required to meet a ±3 percent uncertainty level. The proposed rule would maintain that requirement for high-volume FMPs. However, under this proposed rule, equipment at very-high-volume FMPs would have to comply with a new ±2 percent uncertainty requirement. Consistent with existing guidance, flow-rate equipment at FMPs that measure less than 100 Mcf/day would continue to be exempt from these uncertainty requirements. The BLM would maintain this exemption because it believes that compliance costs for these wells could cause some operators to shut in their wells instead of making changes. The BLM believes the royalties lost by such shut-ins would exceed any royalties that might be gained through upgrades at such facilities. The BLM is interested in any additional information about costs of compliance relative to royalty lost from maintaining the existing exemption.

One area that existing NTLs do not address and that this proposed rule would address is the accuracy of transducers and flow-computer software used in EGM systems. Transducers send electronic data to flow computers, which use that data, along with other data that is programmed into the flow computers, to calculate volumes and flow rates. Currently, the BLM must accept manufacturers' claimed performance specifications when calculating uncertainty. Neither the American Petroleum Institute (API) nor the Gas Processors Association (GPA) has standards for determining these performance specifications. For this reason, the proposed rule would require operators or manufacturers to ''type test'' transducers and flow-computer software at independent testing facilities, using a standard testing protocol, to quantify the uncertainty of transducers and flow-computer software that are already in use and that will be used in the future. The test results would then be incorporated into the calculation of overall measurement uncertainty for each piece of equipment tested.

An integral part of the BLM's evaluation process would be the Production Measurement Team (PMT), made up of measurement experts designated by the BLM.[1] The proposed rule would have the PMT review the results of type testing done on transducers and flow-computer software and make recommendations to the BLM. If approved, the BLM would post the make, model, and range of the transducer or software version on the BLM Web site as being appropriate for use. The BLM would also use the PMT to evaluate and make recommendations on the use of other new types of equipment, such as flow conditioners and primary devices, or new measurement sampling, or analysis methods.

I. Public Comment Procedures

If you wish to comment on the proposed rule, you may submit your comments by any one of several methods specified see **ADDRESSES**. If you wish to comment on the information collection requirements, you should send those comments directly to the OMB as outlined, see **ADDRESSES**; however, we ask that you also provide a copy of those comments to the BLM.

Please make your comments as specific as possible by confining them to issues for which comments are sought in this notice, and explain the basis for your comments. The comments and recommendations that will be most useful and likely to influence agency decisions are:

1. Those supported by quantitative information or studies; and
2. Those that include citations to, and analyses of, the applicable laws and regulations.

The BLM is not obligated to consider or include in the Administrative Record for the rule comments received after the close of the comment period (see **DATES**) or comments delivered to an address other than those listed above (see **ADDRESSES**).

Comments, including names and street addresses of respondents, will be available for public review at the

[1] The PMT would be distinguished from the Department of the Interior's Gas and Oil Measurement Team (DOI GOMT), which consists of members with gas or oil measurement expertise from the BLM, the ONRR, and the Bureau of Safety and Environmental Enforcement (BSEE). BSEE handles production accountability for Federal offshore leases. The DOI GOMT is a coordinating body that enables the BLM and BSEE to consider measurement issues and track developments of common concern to both agencies. The BLM is not proposing a dual-agency approval process for use of new measurement technologies for onshore leases. The BLM anticipates that the members of the BLM PMT would participate as part of the DOI GOMT.

address listed under **ADDRESSES** during regular hours (7:45 a.m. to 4:15 p.m.), Monday through Friday, except holidays.

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

II. Background

The regulations at 43 CFR part 3160, Onshore Oil and Gas Operations, in § 3164.1, provide for the issuance of Onshore Oil and Gas Orders to ''implement and supplement'' the regulations in part 3160. Although they are not codified in the CFR, all Onshore Orders have been issued under Administrative Procedure Act notice and comment rulemaking procedures and apply nationwide to all Federal and Indian (except the Osage Tribe) onshore oil and gas leases. The table in 43 CFR 3164.1(b) lists the existing Orders. This proposed rule would update and replace Order 5, which supplements primarily 43 CFR 3162.4, 3162.7–3, subpart 3163, and subpart 3165. Section 3162.4 covers records and reports. Section 3162.7–3 covers the measurement of gas produced from Federal and Indian (except the Osage Tribe) oil and gas leases. Subpart 3163 covers non-compliance, assessments, and civil penalties. Subpart 3165 covers relief, conflicts, and appeals. Order 5 has been in effect since March 27, 1989 (see 54 FR 8100).

This proposed rule would also supersede the following statewide NTLs:

- NM NTL 92–5, January 1, 1992
- WY NTL 2004–1, April 23, 2004
- CA NTL 2007–1, April 16, 2007
- MT NTL 2007–1, May 4, 2007
- UT NTL 2007–1, August 24, 2007
- CO NTL 2007–1, December 21, 2007
- NM NTL 2008–1, January 29, 2008
- ES NTL 2008–1, September 17, 2008
- AK NTL 2009–1, July 29, 2009
- CO NTL 2014–01, May 19, 2014

Although Order 5 and the statewide NTLs listed above would be superseded by this rule, their provisions would remain in effect for measurement facilities already in place on the effective date of the final rule through the phase-in periods specified in proposed § 3175.60(c) and (d).

Part of the Department of the Interior's responsibility in ensuring correct payment of royalty on gas extracted from Federal onshore and Indian leases is to achieve accurate measurement, proper reporting, and accountability.

In 2007, the Secretary of the Interior commissioned the Subcommittee to report to the Royalty Policy Committee (RPC), which is chartered under the Federal Advisory Committee Act, to provide advice to the Secretary and other Departmental officials responsible for managing mineral leasing activities and to provide a forum for members of the public to voice their concerns about mineral leasing activities. The proposed rule is in part a result of the recommendations contained in the Subcommittee's report, which was issued on December 17, 2007. The proposed changes in this rule also address findings and recommendations made in two GAO reports and one OIG report, including: (1) GAO Report to Congressional Requesters, *Oil and Gas Management: Interior's Oil and Gas Production Verification Efforts Do Not Provide Reasonable Assurance of Accurate Measurement of Production Volumes,* GAO–10–313 (GAO Report 10–313); (2) GAO Report to Congressional Requesters, *Oil and Gas Resources, Interior's Production Verification Efforts and Royalty Data Have Improved, But Further Actions Needed* GAO–15–39 (GAO Report 15–39); and (3) OIG Report, *Bureau of Land Management's Oil and Gas Inspection and Enforcement Program* (CR–EV–0001–2009) (OIG Report).

The GAO found that the Department's measurement regulations and policies do not provide reasonable assurances that oil and gas are accurately measured because, among other things, its policies for tracking where and how oil and gas are measured are not consistent and effective (GAO Report 10–313, p. 20). The report also found that the BLM's regulations do not reflect current industry-adopted measurement technologies and standards designed to improve oil and gas measurement (ibid.). The GAO recommended that Interior provide Department-wide guidance on measurement technologies not addressed in current regulations and approve variances for measurement technologies in instances when the technologies are not addressed in current regulations or Department-wide guidance (see ibid., p. 80). The OIG Report made a similar recommendation that the BLM, ''Ensure that oil and gas regulations are current by updating and issuing onshore orders . . . .'' (see page 11). In its 2015 report, the GAO reiterated that ''Interior's measurement regulations do not reflect current measurement technologies and standards,'' and that this ''hampers the agency's ability to have reasonable assurance that oil and gas production is being measured accurately and verified . . . .'' (GAO Report 15–39, p. 16.) Among its recommendations were that the Secretary direct the BLM to ''meet its established time frame for issuing final regulations for oil measurement.'' (Ibid., p. 32.)

The GAO's recommendations regarding the gas measurement are also one of the bases for the GAO's inclusion of the Department's oil and gas program on the GAO's High Risk List in 2011 (GAO–11–278) and for its continuing to keep the program on the list in the 2013 and 2015 updates. Specifically, the GAO concluded that the BLM does not have ''reasonable assurance that . . . gas produced from federal leases is accurately measured and that the public is getting an appropriate share of oil and gas revenues.'' (GAO–11–278, p.38)

Specifically, of the 110 recommendations made in the 2007 Subcommittee report, 12 recommendations relate directly to improving the operators' measurement and reporting of natural gas volume and heating value. The Subcommittee recommendations focus on the measurement and reporting of heating value because it has a direct impact on royalties. Measuring heating value is as important to calculating royalty as measuring gas volume. As noted previously, Order 5 requires only yearly measurement of natural gas heating value. The BLM does not have any standards for how operators should measure heating value, where they should measure it, how they should analyze it, or on what basis they should report it. The proposed requirements in subpart 3175 would establish these standards.

The proposed changes also address findings and recommendations made in the 2010 and 2015 GAO reports. The 2010 GAO report made 19 recommendations to improve the BLM's ability to ensure that oil and gas produced from Federal and Indian lands is accurately measured and properly reported. Some of those recommendations relate to gas measurement. For example, the report recommends that the BLM establish goals that would allow it to witness gas sample collections; however, the BLM must first establish gas sampling standards as a basis for inspection and enforcement actions. This rulemaking would establish these standards. The 2015 GAO report recommends, among other things, that the BLM issue new regulations pertaining to oil and gas measurement.

Finally, Order 5 is now 26 years old, and many improvements in technology and industry standards have occurred since that time that are not addressed in BLM regulations. In the absence of a new rule, the BLM has had to address these issues through statewide NTLs and site-specific variances. The following summarizes why the BLM is proposing to include some of these changes in this proposed rule:

- The BLM estimates that between 80 percent and 90 percent of gas meters used for royalty determination incorporate EGM systems. EGM systems are not addressed in Order 5, which covers only mechanical chart recorders. BLM requirements for EGM systems, as stated in the various statewide NTLs, are based on the requirements for mechanical recorders in Order 5 and do not address many aspects unique to EGMs, such as volume calculation, data-gathering, and retention requirements. The proposed rule would add requirements specific to EGMs such as new calibration procedures, the use of the latest flow equations, and minimum requirements for quantity transaction records, configuration logs, and event logs.
- Order 5 allows pipe-tapped orifice plates to be used for royalty measurement. Industry has moved away from pipe-tapped orifice plates for custody transfer due to a relatively high degree of measurement uncertainty inherent in that technology. The proposed rule would allow only flange-tapped orifice plates.
- The only industry standard adopted by Order 5 is American Gas Association (AGA) Report No. 3, 1985, which sets standards for orifice plates. This standard has since been superseded based on additional research and analysis. The new standards, which are incorporated by reference in this proposed rule, reduce bias and uncertainty.
- Order 5 does not adopt industry standards related to technologies for EGM systems, calculation of supercompressibility, gas sampling and analysis, calculation of heating value and relative density, or testing protocols for alternate types of primary devices. The proposed rule would add requirements to address all of these shortcomings in Order 5 and would establish the PMT to review new technology.
- Order 5 does not establish testing and approval standards for flow conditioners, transducers used in EGM systems, or flow computer software. To ensure accuracy of measurement, independent verification of these devices, as proposed in this rule, is necessary.

III. Discussion of Proposed Rule

A. Comparison of Order 5 to Proposed Rule

The following chart explains the major changes between Order 5 and the proposed rule.

Order 5	Proposed Rule	Substantive changes
I. Introduction		
A. Authority	No section in this proposed rule	This section of Order 5 would appear in proposed 43 CFR 3170.1. New subpart 3170 was proposed separately in connection with proposed new 43 CFR subpart 3173 (site security), (80 FR 40768, July 13, 2015).
B. Purpose	No section in the proposed rule	The purpose of this proposed rule is to revise and replace Order 5 with a new regulation that would be codified in the CFR.
C. Scope	No section in this proposed rule	See proposed new 43 CFR 3170.2 (80 FR 40802, July 13, 2015).
II. Definitions	43 CFR 3175.10	The list of definitions in the proposed rule would be expanded to include numerous additional technical terms and volume thresholds for applicability of requirements. Definitions relating to enforcement actions would be removed. A list of additional acronyms would be added.
III. Requirements		
A. Required Recordkeeping	No section in this proposed rule	See proposed new 43 CFR 3170.7 (80 FR 40804, July 13, 2015).
B. General	43 CFR 3175.31	The proposed rule would adopt, in whole or in part, the latest applicable versions of relevant API and GPA standards. Timelines for retrofitting existing equipment to comply with the rule would be added on a sliding scale based on four different volume thresholds. These volume thresholds would be established to allow exceptions to specific requirements for lower-volume FMPs. This proposed rule would remove the enforcement, corrective action, and abatement period provisions of Order 5. In their place, the BLM would develop an internal inspection and enforcement handbook that would direct inspectors on how to classify a violation, how to determine what the corrective action should be, and the proper timeframe for correcting the violation. This change would improve consistency and clarity in enforcement nationally. The enforcement actions listed in Order 5 give the impression that they are mandatory. In practice, the violations' severity and corrective action timeframes should be decided on a case-by-case basis, using the definitions in the regulations. In deciding how severe a violation is, BLM inspectors must take into account whether a violation "could result in immediate, substantial, and adverse impacts on . . . production accountability, or royalty income." What constitutes a "major" violation in a high-volume meter could, for example, be very different from what constitutes a "major" violation in a meter measuring substantially lower production. The authorized officer (AO) would use the enforcement handbook in conjunction with 43 CFR subpart 3163 when determining appropriate assessments and civil penalties.
• Adoption of AGA Report No. 3.		

Order 5	Proposed Rule	Substantive changes
• Applicability to existing and future meters. • Exemptions for meters measuring less than 100 Mcf/day. • Enforcement.		
C. Gas Measurement by Orifice Meter		
Paragraphs 1, 2, 3, 6, 8, 9, 10, 11 (Orifice plate and meter tube standards).	43 CFR 3175.80	The proposed rule would adopt, in whole or in part, the current API standards for orifice plates and combine all the requirements for orifice plates in one section.
Paragraphs 4, 5, 7, 12, 13, 14, 15, 16, 17, 18, 19 (Chart recorder standards).	43 CFR 3175.90–3175.94	The proposed rule would restrict the use of mechanical recorders to those FMPs measuring 100 Mcf/day or less. In addition, it would establish new standards for volume calculation, verification, and design parameters for manifolds and gauge lines. The proposed rule would also lower the volume threshold for required use of continuous temperature recorders from 200 Mcf/day or less, to 15 Mcf/day or less.
Paragraph 20 (Volume estimate for malfunction or out of service).	43 CFR 3175.126	The requirement for estimating volumes when metering equipment is malfunctioning or out-of-service would make clear the acceptable methods of estimating volume and associated documentation.
Paragraph 21 (Volume calculation AGA 3).	43 CFR 3175.90–3175.94, 3175.100–3175.103.	The proposed rule would update the reference to industry standards for required flow-rate calculations. Requirements would be added to clarify how volume is determined from the calculated flow rate.
Paragraph 22 (Location of meter requirement).	43 CFR 3175.70	Requirements for obtaining approval for off-lease measurement and commingling and allocation would be revised and moved into the proposed new rule that would replace Onshore Oil and Gas Order No. 3 (Order 3) published previously (proposed 43 CFR subpart 3173), 80 FR 40768 (July 13, 2015), but would be referenced in this subpart.
Paragraph 23 (Btu requirement)	43 CFR 3175.110–3175.121	The requirements for gas sampling and analysis would be expanded to include requirements for sampling location and methods, sampling frequency, analysis methods, and the minimum number of components to be analyzed. This section would also define the effective date of the heating value and relative density determined from the sample.
Paragraph 24 (Calibration form information requirement).	43 CFR 3175.90, 3175.92, 3175.100, and 3175.102.	The information required on meter calibration reports would be expanded for both mechanical recorders and EGM systems.
Paragraph 25 (Atmospheric pressure requirement).	43 CFR 3175.90, 3175.92, 3175.100, and 3175.102.	The proposed rule would change the basis for determining atmospheric pressure from a contract value to a measurement or calculation based on elevation. The calculation is prescribed in the proposed rule.
Paragraph 26 (Method and frequency—specific gravity).	43 CFR 3175.110–3175.120	Order 5 has no requirements pertaining to the determination of relative density. The proposed rule would establish methods for deriving the relative density from the gas analysis.
No requirements for EGM systems—Addressed in statewide NTLs.	43 CFR 3175.100–3175.126	Order 5 does not address EGM systems; however, these devices are addressed in the statewide NTLs for electronic flow computers. The proposed rule would adopt many of the provisions of the statewide NTLs and add requirements relating to on-site information, gauge lines, verification, test equipment, calculations, and information generated and retained by the EGM system.
D. Gas Measurement by Other Methods or at Other Locations Acceptable to the Authorized Officer.	43 CFR 3175.47, 3175.48, and 3175.70.	Requirements for obtaining approval for off-lease measurement and commingling and allocation would be revised and moved into the new proposed rule that would replace Order 3 published previously and cited above, but would be referenced in this subpart. In addition, this proposed change would establish a consistent and nationwide process for review and approval of alternate primary devices and flow conditioners used in conjunction with flange-tapped orifice plates.
No requirements for transducer or flow computer testing.	43 CFR 3175.130–3175.144	The proposed rule would establish a testing protocol and approval process for transducers used in EGM systems and flow-computer software.
No requirements for reporting of volume and heating value.	43 CFR 3175.126	The proposed rule would establish standards for heating value reporting, averaging heating value from multiple FMPs and multiple samples, and volume reporting.
IV. Variance from Minimum Standards.	No section in this proposed rule	See proposed new 43 CFR 3170.6 (80 FR 40804, July 13, 2015).

Order 5	Proposed Rule	Substantive changes
No immediate assessments	43 CFR 3175.150	The proposed rule would add 10 new violations that would be subject to an immediate assessment of $1,000, as follows: (1) New FMP orifice plate inspections not conducted and documented; (2) Routine FMP orifice plate inspections not conducted and documented; (3) Visual meter-tube inspection not conducted and documented; (4) Detailed meter-tube inspections not conducted and documented; (5) Initial mechanical-recorder verification not conducted and documented; (6) Routine mechanical-recorder verifications not conducted and documented; (7) Initial EGM-system verification not conducted and documented; (8) Routine EGM-system verification not conducted and documented; (9) Spot samples for low-volume and marginal-volume FMPs not taken at the required frequency; and (10) Spot samples for high-volume and very-high-volume FMPs not taken at the required frequency.

B. Section-by-Section Analysis

This proposed rule would be codified primarily in a new 43 CFR subpart 3175. As noted previously, the BLM has already proposed a rule to revise and replace Order 3 (site security), 80 FR 40768 (July 13, 2015). It is the BLM's intent to codify any final rule resulting from that proposal at new 43 CFR subpart 3173. The BLM also anticipates proposing a new rule to replace Onshore Oil and Gas Order No. 4, 54 FR 8086 (February 24, 1989), governing measurement of oil for royalty purposes. The BLM's intent is to codify any final rule governing oil measurement at new 43 CFR subpart 3174. Given this structure, it is the BLM's intent that part 3170, which was proposed together with proposed 43 CFR subpart 3173, would contain definitions of certain terms common to more than one of the proposed rules, as well as other provisions common to all rules, *i.e.,* provisions prohibiting by-pass of and tampering with meters; procedures for obtaining variances from the requirements of a particular rule; requirements for recordkeeping, records retention, and submission; and administrative appeal procedures. Those common provisions in new subpart 3170 were already proposed in connection with the rule to replace Order 3.

In addition to the new subpart 3175 provisions, the BLM is also proposing changes to certain other provisions in 43 CFR subparts 3162, 3163, and 3165. The proposed provisions related to the new subpart 3175 are discussed first in the section-by-section analysis below; changes to other subparts are discussed at the end of the section-by-section analysis.

Subpart 3175 and Related Provisions

§ 3175.10 Definitions and Acronyms

The proposed rule would include numerous new definitions because much of the terminology used in the proposed rule is technical in nature and may not be readily understood by all readers. The BLM would add other definitions because their meaning, as used in the proposed rule, may be different from what is commonly understood, or the definition would include a specific regulatory requirement.

Definitions of terms commonly used in gas measurement or which are already defined in 43 CFR parts 3000, 3100, or 3160 are not discussed in this preamble.

The proposed rule would define the terms ''primary device,'' ''secondary device,'' and ''tertiary device,'' which together measure the amount of natural gas flow. All differential types of gas meters consist of at least a primary device and a secondary device. The primary device is the equipment that creates a measureable and predictable pressure drop in response to the flow rate of fluid through the pipeline. It includes the pressure-drop device, device holder, pressure taps, required lengths of pipe upstream and downstream of the pressure-drop device, and any flow conditioners that may be used to establish a fully-developed symmetrical flow profile.

A flange-tapped orifice plate is the most common primary device. It operates by accelerating the gas as it flows through the device, similar to placing one's thumb at the end of a garden hose. This acceleration creates a difference between the pressure upstream of the orifice and the pressure downstream of the orifice, which is known as differential pressure. It is the only primary device that is approved in Order 5 and in this proposed rule and would not require further specific approval. Other primary devices, such as cone-type meters, operate much like orifice plates and the BLM could approve their use under the requirements of proposed § 3175.47.

The secondary device measures the differential pressure along with static pressure and temperature. The secondary device consists of either the differential-pressure, static-pressure, and temperature transducers in an EGM system or a mechanical recorder (including the differential, static, and temperature elements, and the clock, pens, pen linkages, and circular chart). In the case of an EGM system, there is also a ''tertiary device,'' namely, the flow computer and associated memory, calculation, and display functions, which calculates volume and flow rate based on data received from the transducers and other data programmed into the flow computer.

The proposed rule would add definitions for ''component-type'' and ''self-contained'' EGM systems. The distinction is necessary for the determination of overall measurement uncertainty. To determine overall measurement uncertainty under proposed § 3175.30(a), it is necessary to know the uncertainty, or risk of measurement error, of the transducers that are part of the EGM system. Therefore, the BLM would need to be able to identify the make, model, and upper range limit (URL) of each transducer because the uncertainty of the transducer varies between makes, models, and URLs.

Some EGM systems are sold as a complete package, defined as a self-contained EGM system, which includes the differential-pressure, static-pressure, and temperature transducers, as well as the flow computer. The EGM package is identified by one make and model number. The BLM can access the performance specifications of all three transducers through the one model number, as long as the transducers have not been replaced by different makes or models.

Other EGM systems are assembled using a variety of transducers and flow computers and cannot be identified by a single make and model number. Instead, the BLM would identify each transducer by its own make and model. These are referred to as ''component'' EGM systems. Component systems would include EGM systems that started out as self-contained systems, but one or more of whose transducers have been changed to a different make and model.

The proposed rule would add a definition for ''hydrocarbon dew point.'' The hydrocarbon dew point is the temperature at which liquids begin to form within a gas mixture. Because it is not common to determine hydrocarbon dew points for wellhead metering applications on Federal and Indian leases, the BLM would establish a default value using the gas temperature at the meter. By definition, the gas in a separator (if one is used) is in equilibrium with the natural gas liquids, which are at the hydrocarbon dew point. Cooler temperatures between the outlet of the separator and the primary device can result in condensation of heavy gas components, in which case the lower temperature at the primary device would still represent the hydrocarbon dew point at the primary device. The AO may approve a different hydrocarbon dew point if data from an equation-of-state, chilled mirror, or other approved method is submitted.

The proposed rule would define ''marginal-volume FMP'' as an FMP that measures a default volume of 15 Mcf/day or less. FMPs classified as ''marginal-volume'' would be exempt from many of the requirements in this proposed rule. The 15 Mcf/day default threshold was derived by performing a discounted cash-flow analysis to account for the initial investment of equipment that may be required to comply with the proposed standards for FMPs that are classified as low-volume FMPs. Assumptions in the discounted cash-flow model included:

• $12,000/year/well operating cost (not including measurement-related expense);

• Verification, orifice-plate inspection, meter-tube inspection, and gas sampling expenditures as would be required for a low-volume FMP in the proposed rule;

• A before-tax rate of return (ROR) of 15 percent;

• An exponential production-rate decline of 10 percent per year; and

• 10-year equipment life.

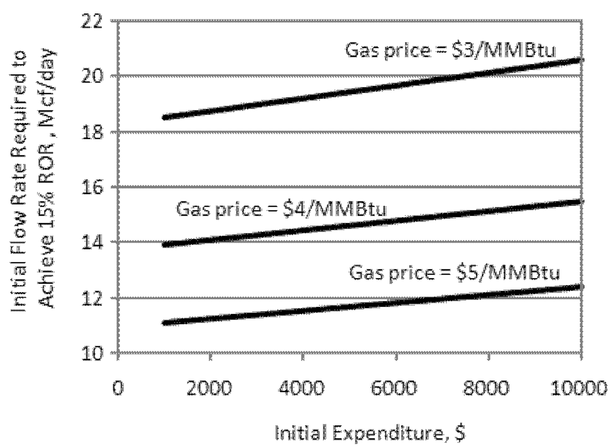

Figure 1

The model calculated the minimum initial flow rate needed to achieve a 15 percent ROR for various levels of investment in measurement equipment that would be required of a low-volume FMP. The ROR would be from the continued sale of produced gas that would otherwise be lost because the lease, unit participating area (PA), or communitized area (CA) would be shut-in if there were no exemptions for marginal-volume FMPs. Figure 1 shows the results of the modeling for assumed gas sales prices of $3/MMBtu, $4/MMBtu, and $5/MMBtu.

Both wellhead spot prices (Henry Hub) and New York Mercantile Exchange futures prices for natural gas averaged approximately $4/MMBtu for 2013 and 2014. The U.S. Energy Information Administration projects the price for natural gas to range between $5/MMBtu and $10/MMBtu through the end of 2040, depending on the rate at which new natural gas discoveries are made and projected economic growth.[2] Assuming a $4/MMBtu gas price from Figure 1, a 15 percent ROR could be achieved for meters with initial flow rates of at least 15 Mcf/day, for an initial investment in metering equipment up to about $8,000. For wells with initial flow rates less than 15 Mcf/day, our analysis indicates that it may not be profitable to invest in the necessary equipment to meet the proposed requirements for a low-volume FMP. Instead, it would be more economic for an operator to shut in the FMP than to make the necessary investments. Therefore, 15 Mcf/day is proposed as the default threshold of a marginal-volume FMP. The AO may approve a higher threshold where circumstances warrant.

The proposed rule would define ''low-volume FMP'' as an FMP flowing 100 Mcf/day or less but more than 15 Mcf/day. Low-volume FMPs would have to meet minimum requirements to ensure that measurements are not biased, but would be exempt from the minimum uncertainty requirements in § 3175.30(a) of the proposed rule. It is anticipated that this classification would encompass many FMPs, such as those associated with plunger-lift operations, where attainment of minimum uncertainty requirements would be difficult due to the high fluctuation of flow-rate and other factors. The costs to retrofit these FMPs to achieve minimum uncertainty levels could be significant, although no economic modeling was performed because costs are highly variable and speculative. The exemptions that would be granted for low-volume FMPs are similar to the exemptions granted for meters measuring 100 Mcf/day or less in Order 5 and in BLM requirements stated in the statewide NTLs for electronic flow computers (EFCs).

[2] ''Annual Energy Outlook 2014 with Projections to 2040'', U.S. Department of Energy, Energy Information Administration (DOE/EIA–0383(2014), April, 2014, Figure MT–41.

The proposed rule would define ''high-volume FMP,'' as an FMP flowing more than 100 Mcf/day, but not more than 1,000 Mcf/day. Proposed requirements for high-volume FMPs would ensure that there is no statistically significant bias in the measurement and would achieve an overall measurement of uncertainty of ±3 percent or less. The BLM anticipates that the higher flow rates would make retrofitting to achieve minimum uncertainty levels more economically feasible. The requirements for high-volume FMPs would be similar to current BLM requirements as stated in the statewide NTLs for EFCs.

The proposed rule would define ''very-high-volume FMP,'' as an FMP flowing more than 1,000 Mcf/day. Proposed requirements for very-high-volume FMPS would require lower uncertainty than would be required for high-volume FMPs (±2 percent, compared to ±3 percent) and would increase the frequency of primary device inspection and secondary device verification. Stricter measurement accuracy requirements would be imposed for very-high-volume FMPs due to the risk of mis-measurement having a significant impact on royalty calculation. The BLM anticipates that FMPs in this class operate under relatively ideal flowing conditions where lower levels of uncertainty are achievable and the economics for making necessary retrofits are favorable.

The proposed rule would adopt three definitions from API Manual of Petroleum Measurement Standards (MPMS) 21.1. The terms ''lower calibrated limit'' and ''upper calibrated limit'' would replace the term ''span'' as used in the statewide NTLs for EFCs.

In addition, the term ''redundancy verification'' would be added to address verifications done by comparing the readings from two sets of transducers installed on the same primary device.

§ 3175.20 General Requirements

Proposed § 3175.20 would require measurement of all gas removed or sold from Federal or Indian leases and unit PAs or CAs that include one or more Federal or Indian leases to comply with the standards of the proposed rule (unless the BLM grants a variance under proposed § 3170.6).

§ 3175.30 Specific Performance requirements

Proposed § 3175.30 would set overall performance standards for measuring gas produced from Federal and Indian leases, regardless of the type of meters used. Order 5 has no explicit statement of performance standards. The performance standards would provide specific objective criteria with which the BLM could analyze meter systems not specifically allowed under the proposed rule. The performance standards also formed the basis of determining the standards that would apply to each flow-rate class of meter (*i.e.,* marginal, low, high, and very-high volume).

The first performance standard in proposed § 3175.30(a) is the maximum allowable flow-rate measurement uncertainty. Uncertainty indicates the risk of measurement error. For high-volume FMPs (flow rate greater than 100 Mcf/day, but less than or equal to 1,000 Mcf/day), the maximum allowed overall flow-rate measurement uncertainty would be ±3 percent, which is the same as what is currently required in all of the statewide NTLs for EFCs; therefore, this requirement does not represent a change from existing standards. For very-high-volume FMPs (flow rate of more than 1,000 Mcf/day), the maximum allowable flow-rate uncertainty would be reduced to ±2 percent, because uncertainty in higher-volume meters represents a greater risk of affecting royalty than in lower-volume meters. In addition, upgrades necessary to achieve an uncertainty of ±2 percent for very-high-volume FMPs will be more cost effective. Not only do the higher flow rates make these necessary upgrades more economic, many of the measurement uncertainty problems associated with lower volume FMPs, such as intermittent flow, are not as prevalent with higher volume FMPs. This is a change from the existing statewide NTLs, which use the ±3 percent requirement for all meters measuring more than 100 Mcf/day. As with the existing statewide NTLs, meters measuring 100 Mcf/day or less (low-volume FMPs and marginal-volume FMPs) would be exempt from maximum uncertainty requirements.

This proposed section would also specify the conditions under which flow-rate uncertainty must be calculated. Flow-rate uncertainty is a function of the uncertainty of each variable used to determine flow rate. The uncertainty of variables such as differential pressure, static pressure, and temperature is dynamic and depends on the magnitude of the variables at a point in time.

Proposed § 3175.30(a)(3) lists two sources of data to use for uncertainty determinations. The best data source for average flowing conditions at the FMP would be the monthly averages typically available from a daily quantity transaction record. However, daily quantity transaction records are not usually readily available to the AO at the time of inspection because they must usually be requested by the BLM and provided by the operator ahead of time. If the daily quantity transaction record is not available to the AO, the next best source for uncertainty determinations would be the average flowing parameters from the previous day, which are required under proposed § 3175.101(b)(4)(ix) through (xi) of this rule.

The BLM would enforce measurement uncertainty using standard calculations such as those found in API MPMS 14.3.1, which are incorporated into the BLM uncertainty calculator (*www.wy.blm.gov*). BLM employees use the uncertainty calculator to determine the uncertainty of meters that are used in the field. However, existing and previous versions of the uncertainty calculator do not account for the effects of relative density uncertainty because these effects have not been quantified. The data used to calculate relative density under proposed § 3175.120(c) would allow the BLM to quantify relative density uncertainty by performing a statistical analysis of historic relative density variability and include it in the determination of overall measurement uncertainty, making these uncertainty calculations more accurate.

Proposed § 3175.30(b) would add an uncertainty requirement for the measurement of heating value. This would be added because both heating value and volume directly affect royalty calculation if gas is sold at arm's length on the basis of a per-MMBtu price. (The vast majority of gas sold domestically in the United States is priced on a $/MMBtu basis.) In that situation, the royalty is computed by the following equation: Royalty owed = measured volume × heating value per unit volume (*i.e.,* MMBtu/Mcf) × royalty value (*i.e.,* the arm's-length price in $/MMBtu) × royalty rate. Thus, a 5 percent error in heating value would result in the same error in royalty as a 5 percent error in volume measurement.

The BLM recognizes that the heating value determined from a spot sample only represents a snapshot in time, and the actual heating value at any point after the sample was taken may be different. The probable difference is a function of the degree of variability in heating values determined from previous samples. If, for example, the previous heating values for a meter are very consistent, then the BLM would expect that the difference between the heating value based on a spot sample and the actual heating value at any given time after the spot sample was taken would be relatively small. The opposite would be true if the previous heating values had a wide range of variability. Therefore, the uncertainty of the heating value calculated from spot sampling would be determined by performing a statistical analysis of the historic variability of heating values over the past year.

For composite sampling and on-line gas chromatographs, the BLM would determine the heating value uncertainty by analyzing the equipment, procedures, and calculations used to derive the heating value.

The uncertainty limits proposed for heating value are based on the annualized cost of spot sampling and analysis as compared to the royalty risk from the resulting heating value uncertainty. The BLM used the data collected for the gas variability study (see the discussion of proposed § 3175.115 below) as the basis of this analysis. For high-volume FMPs, the BLM determined that the cost to industry of achieving an average annual heating value uncertainty of ±2 percent by using spot sampling methods would approximately equal the royalty risk resulting from the same ±2 percent uncertainty in heating value. For very-high-volume FMP's, an average annual heating value uncertainty of ±1 percent would result in a cost to industry that is approximately equal to the royalty risk of the uncertainty. The proposed rule therefore would prescribe these respective levels as the allowed average annual heating value uncertainty.

Proposed § 3175.30(c) would establish the degree of allowable bias in a measurement. Bias, unlike uncertainty, results in measurement error; uncertainty only indicates the risk of measurement error. For all FMPs, except marginal FMPs, no statistically significant bias would be allowed. The BLM acknowledges that it is virtually impossible to completely remove all bias in measurement. When a measurement device is tested against a laboratory device, there is often slight disagreement, or apparent bias, between the two. However, both the measurement device being tested and the laboratory device have some inherent level of uncertainty. If the disagreement between the measurement device being tested and the laboratory device is less than the uncertainty of the two devices combined, then it is not possible to distinguish apparent bias in the measurement device being tested from inherent uncertainty in the devices (sometimes referred to as ''noise'' in the data). Therefore, apparent bias that is less than the uncertainty of the two devices combined is not considered to be statistically significant.

Although bias is not specifically addressed in Order 5 or the statewide NTLs, the intent of the existing standards is to reduce bias to less than significant levels. Therefore, minimizing bias does not represent a change in BLM policy.

The bias requirement does not apply to marginal-volume FMPs because marginal-volume FMPs are measuring such low volumes that any bias, even if it is statistically significant, results in little impact to royalty. The small amount of royalty loss (or gain) resulting from bias would be much less than the royalty lost if production were to cease altogether. If it is uneconomic to upgrade a meter to eliminate bias, the operator could opt to shut in production rather than making the necessary upgrades. Therefore, the BLM has determined that it is in the public interest to accept some risk of measurement bias in marginal-volume FMPs in view of maintaining gas production.

Proposed § 3175.30(d) would require that all measurement equipment must allow for independent verification by the BLM. As with the bias requirements, Order 5 and the statewide NTLs for EFCs only allow meters that can be independently verified by the BLM and, therefore, this requirement would not be a change from existing policy. The verifiability requirement in this section would prohibit the use of measurement equipment that does not allow for independent verification. For example, if a new meter was developed that did not record the raw data used to derive a volume, that meter could not be used at an FMP because without the raw data the BLM would be unable to independently verify the volume. Similarly, if a meter was developed that used proprietary methods which precluded the ability to recalculate volumes or heating values, or made it impossible for the BLM to verify its accuracy, its use would also be prohibited.

§ 3175.31 Incorporation by Reference

The proposed rule would incorporate a number of industry standards, either in whole or in part, without republishing the standards in their entirety in the CFR, a practice known as incorporation by reference. These standards were developed through a consensus process, facilitated by the API and the GPA, with input from the oil and gas industry. The BLM has reviewed these standards and determined that they would achieve the intent of §§ 3175.30 and 3175.46 through 3175.125 of this proposed rule. The legal effect of incorporation by reference is that the incorporated standards become regulatory requirements. This proposed rule would incorporate the current versions of the standards listed.

Some of the standards referenced in this section would be incorporated in their entirety. For other standards, the BLM would incorporate only those sections that are enforceable, meet the intent of § 3175.30 of this proposed rule, or do not need further clarification.

The proposed incorporation of industry standards follows the requirements found in 1 CFR part 51. Industry standards proposed for incorporation are eligible under 1 CFR 51.7 because, among other things, they will substantially reduce the volume of material published in the **Federal Register**; the standards are published, bound, numbered, and organized; and the standards proposed for incorporation are readily available to the general public through purchase from the standards organization or through inspection at any BLM office with oil and gas administrative responsibilities. 1 CFR 51.7(a)(3) and (4). The language of incorporation in proposed 43 CFR 3174.4 meets the requirements of 1 CFR 51.9. Where appropriate, the BLM proposes to incorporate an industry standard governing a particular process by reference and then impose requirements that are in addition to and/or modify the requirements imposed by that standard (*e.g.,* the BLM sets a specific value for a variable where the industry standard proposed a range of values or options).

All of the API and GPA materials for which the BLM is seeking incorporation by reference are available for inspection at the BLM, Division of Fluid Minerals; 20 M Street SE., Washington, DC 20003; 202–912–7162; and at all BLM offices with jurisdiction over oil and gas activities. The API materials are available for inspection at the API, 1220 L Street NW., Washington DC 20005; telephone 202–682–8000; API also offers free, read-only access to some of the material at *www.publications.api.org*. The GPA materials are available for inspection at the GPA, 6526 E. 60th Street, Tulsa, OK 74145; telephone 918–493–3872.

The following describes the API and GPA standards that the BLM proposes to incorporate by reference into this rule:

API Manual of Petroleum Measurement Standards (MPMS) Chapter 14, Section 1, Collecting and Handling of Natural Gas Samples for Custody Transfer, Sixth Edition, February 2006, Reaffirmed 2011 (''API

14.1.12.10''). The purpose of this standard is to provide a comprehensive guideline 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 2,* Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases, Second Edition, August 1994, Reaffirmed March 1, 2006 (''API 14.2''). This standard 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.

API MPMS, Chapter 14, Section 3, Part 1, General Equations and Uncertainty Guidelines, Fourth Edition, September 2012, Errata, July 2013. (''API 14.3.1.4.1''). This standard provides engineering equations and uncertainty estimations for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.

API MPMS Chapter 14, Section 3, Part 2, Specifications and Installation Requirements, Fourth Edition, April 2000, Reaffirmed 2011 (''API 14.3.2,'' ''API 14.3.2.4,'' ''API 14.3.2.5.1 through API 14.3.2.5.4,'' ''API 14.3.2.5.5.1 through API 14.3.2.5.5.3,'' ''API 14.3.2.6.2,'' ''API 14.3.2.6.3,'' ''API 14.3.2.6.5,'' and ''API 14.3.2, Appendix 2–D''). This standard provides construction and installation requirements, and standardized implementation recommendations for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.

API MPMS Chapter 14, Section 3, Part 3, Natural Gas Applications, Fourth Edition, November 2013 (''API 14.3.3,'' ''API 14.3.3.4,'' and ''API 14.3.3.5.'' and ''API 14.3.3.5.6,''). This standard is an application guide for the calculation of natural gas flow through a flange-tapped, concentric orifice meter.

API MPMS, Chapter 14, 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 (''API 14.5,'' ''API 14.5.3.7,'' and ''API 14.5.7.1''). This standard presents procedures for calculating, at base conditions from composition, the following properties of natural gas mixtures: gross heating value, relative density (real and ideal), compressibility factor, and theoretical hydrocarbon liquid content.

API MPMS Chapter 21, Section 1, Electronic Gas Measurement, Second Edition, February 2013 (''API 21.1,'' ''API 21.1.4,'' ''API 21.1.4.4.5,'' ''API 21.1.5.2,'' ''API 21.1.5.3,'' ''API 21.1.5.4,'' ''API 21.1.5.4.2,'' ''API 21.1.5.5,'' ''API 21.1.5.6,'' ''API 21.1.7.3,'' ''API 21.1.7.3.3,'' ''API 21.1.8.2,'' ''API 21.1.8.2.2.2, Equation 24,'' ''API 21.1.9,'' ''API 21.1 Annex B,'' ''API 21.1 Annex G,'' ''API 21.1 Annex H, Equation H.1,'' and ''API 21.1 Annex I''). This standard describes the minimum specifications for electronic gas measurement systems 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.

API MPMS Chapter 22, Section 2, Differential Pressure Flow Measurement Devices, First Edition, August 2005, Reaffirmed 2012 (''API 22.2''). This standard is a testing protocol for any flow meter operating on the principle of a local change in flow velocity, caused by the meter geometry, giving a corresponding change of pressure between two reference locations.

GPA Standard 2166–05, Obtaining Natural Gas Samples for Analysis by Gas Chromatography, Revised 2005 (''GPA 2166–05 Section 9.1,'' ''GPA 2166.05 Section 9.5,'' ''GPA 2166–05 Sections 9.7.1 through 9.7.3,'' ''GPA 2166–05 Appendix A,'' ''GPA 2166–05 Appendix B.3,'' ''GPA 2166–05 Appendix D''). 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 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Revised 2000 (''GPA 2261–00'', ''GPA 2261–00, Section 4,'' GPA 2261–00, Section 5,'' ''GPA 2261–00, Section 9''). This standard establishes a method to determine the chemical composition of natural gas and similar gaseous mixtures.

GPA Standard 2198–03, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends, Revised 2003. (''GPA 2198–03''). This standard establishes procedures for selecting the proper natural gas and natural gas liquids reference standards, preparing the standards for use, verifying the accuracy of composition as reported by the manufacturer, and the proper care and storage of those standards to ensure their integrity as long as they are in use.

§§ 3175.40–3175.45 Measurement Equipment Approved by Standard or Make and Model

Proposed § 3175.40 would provide that the specific types of measurement equipment identified in proposed §§ 3175.41—3175.45 could be installed at FMPs without further approval. Flange-tapped orifice plates (proposed § 3175.41) have been rigorously tested and shown that they are capable of meeting the performance standards of proposed § 3175.30(a). Mechanical recorders (proposed § 3175.42) have been in use on gas meters for more than 90 years in custody-transfer applications and their ability to meet the performance standards of proposed §§ 3175.30(b) and (c) is well-established. Because mechanical recorders would be limited to marginal-volume and low-volume FMPs under the proposed rule, they would not have to meet the uncertainty requirements of proposed § 3175.30(a).

While EGM systems are widely accepted for use in custody-transfer applications, there are currently no standardized protocols by which they are tested to document their performance capabilities and limitations. Proposed § 3175.43 (transducers) and proposed § 3175.44 (flow computer software) would require these components of an EGM system to be tested under the protocols proposed in §§ 3175.130 and 3175.140, respectively, in order to be used at high- or very-high-volume FMPs.

To make the review and approval process consistent, all data received from the testing would be reviewed by the PMT, who would make recommendations to the BLM. If approved, the BLM would post the make, model, and range or software version on the BLM Web site at *www.blm.gov* as being appropriate for use at high- and very-high-volume FMPs. The posting could include conditions of use. This would be a new requirement. Transducers used at marginal- and low-volume FMPs would not require testing under proposed § 3175.130 or approval through the PMT. The primary purpose of the testing protocol is to determine the uncertainty of the transducer under a variety of operating conditions. Because marginal- and low-volume FMPs are not subject to the uncertainty requirements under § 3175.30(a), testing the performance of the transducer would be unnecessary in that context. However, flow computer software used at marginal-volume and low-volume FMPs (proposed § 3175.44) would not be exempt from testing under proposed § 3175.140.

Gas chromatographs (proposed § 3175.45) are not addressed in Order 5 or statewide NTLs. They have been rigorously tested and used in industry for custody transfer applications and their ability to meet the requirements of § 3175.30 has been demonstrated. Therefore, the proposed rule would allow their use in determining heating value and relative density as long as they meet the design, operation, verification, calibration, and other requirements of proposed §§ 3175.117 and 3175.118.

§§ 3175.46 and 3175.47 Approval of Isolating Flow Conditioners and Differential Primary Devices Other Than Flange-Tapped Orifice Plates

Proposed §§ 3175.46 and 3175.47 contain new provisions that would establish a consistent nationwide process that the PMT would use to approve certain other devices without the BLM having to update its regulations, issue other forms of guidance such as NTLs, or grant approvals on a case-by-case basis. The PMT would act as a central advisory body for approving equipment and methods not addressed in the proposed regulations. As noted above, the PMT is a panel of oil and gas measurement experts designated by the BLM that would be charged with reviewing changes in industry measurement technology. These proposed sections would describe and clarify the process for approval of specific makes and models of other primary devices and flow conditioners used in conjunction with flange-tapped orifice plates, including specific testing protocols and procedures for review of test data. These sections also would clarify the makes and models of devices approved for use and the conditions under which operators may use them.

Under the proposed rule, if the PMT recommends, and the BLM approves new equipment, the BLM would post the make and model of the device on the BLM Web site *www.blm.gov* as being appropriate for use at an FMP for gas measurement going forward—*i.e.,* subsequent users of the technology would not have to go through the PMT process. The web posting identifying the equipment or technology would include, as appropriate, conditions of use.

Proposed § 3175.46 would prescribe a testing protocol for flow conditioners used in conjunction with flange-tapped orifice plates. The proposed rule references the current API MPMS 14.3.2 (2000), Appendix 2–D, which provides a testing protocol for flow conditioners. Based on the BLM's experience with other testing protocols, the BLM could prescribe additional testing beyond what Appendix 2–D requires, to meet the intent of the uncertainty limits in proposed § 3175.30(a). Additional testing protocols would be posted on the BLM's Web site at *www.blm.gov*.

Proposed § 3175.47 would prescribe a testing protocol for differential types of primary devices other than flange-tapped orifice plates. The protocol is based largely on API MPMS 22.2. The BLM is aware that the API is in the process of making significant changes to this protocol; however, the modifications have not yet been published. Therefore, the BLM could include additional testing requirements beyond those in the current version of API MPMS 22.2 to help ensure that tests are conducted and applied in a manner that meets the intent of proposed § 3175.30 of this rule. The BLM would post any additional testing protocols on its Web site at *www.blm.gov*.

§ 3175.48 Linear Measurement Devices

Proposed § 3175.48 would provide a process for the BLM to approve linear measurement devices such as ultrasonic meters, Coriolis meters, and other devices on a case-by-case basis.

§ 3175.60 Timeframes for compliance

Proposed § 3175.60(a) would require all meters installed after the effective date of the final rule to meet the proposed requirements. Proposed paragraph (b) would set timeframes for compliance with the provisions of this rule for equipment existing on the effective date of the final rule. The timeframes for compliance generally would depend on the average flow rate at the FMP. Higher-volume FMPs would have shorter timeframes for compliance with this proposed rule because they present a greater risk to royalty than lower-volume FMPs and the costs to comply could be recovered in a shorter period of time.

Proposed paragraphs (b)(1)(ii) and (b)(2)(ii) include some exceptions to the compliance timelines for high-volume and very-high-volume FMPs. To implement the gas-sampling frequency requirements in proposed § 3175.115, the gas-analysis submittal requirements in proposed § 3175.120(f) would go into effect immediately for high-volume and very-high-volume FMPs on the effective date of the final rule. This would allow the BLM to immediately start developing a history of heating values and relative densities at FMPs to determine the variability and uncertainty of these values.

The BLM is not proposing to ''grandfather'' existing equipment. Operators would be required to upgrade measurement equipment at FMPs to meet the new standards, except for those FMPs that are specifically exempted in the rule. The reason for not grandfathering existing equipment is that compliance with the API and GPA standards that would be adopted by the proposed rule is necessary to minimize bias and meet the proposed uncertainty standards. The BLM is responsible for ensuring accurate, unbiased, and verifiable measurement, as stated in proposed § 3175.30 of this rule, regardless of when the measurement equipment was installed.

Although this rule would supersede Order 5 and any NTLs, variance approvals, and written orders relating to gas measurement, paragraph (c) would specify that their requirements would remain in effect through the timeframes specified in paragraph (b). Paragraph (d) would establish the dates on which the applicable NTLs, variance approvals, and written orders relating to gas measurement would be rescinded. These dates correspond to the phase-in timeframes given in paragraph (b).

§ 3175.70 Measurement Location

Proposed § 3175.70 would require prior approval for commingling of production with production from other leases, unit PAs, or CAs or non-Federal properties before the point of royalty measurement and for measurement off the lease, unit, or CA (referred to as ''off-lease measurement''). The process for obtaining approval is included in the proposed rule that would replace Order 3 (new subpart 3173) referred to previously.

§ 3175.80 Flange-Tapped Orifice Plates (Primary Device)

Proposed § 3175.80 would prescribe standards for the installation, operation, and inspection of flange-tapped orifice plate primary devices. The standards would include requirements described in the proposed rule as well as requirements described in API standards that would be incorporated by reference. Table 1 is included in this proposed section to clarify and provide easy reference to which requirements would apply to different aspects of the primary device and to adopt specific API standards as necessary. The first column of Table 1 lists the subject area for which a standard exists. The second column of Table 1 contains a reference to the standard that applies to the subject area described in the first column. For subject areas where the BLM would adopt an API standard verbatim, the specific API reference is shown. For subject areas where there is no API standard or the API standard requires additional clarification, the reference in Table 1 cites the paragraph in the proposed section that addresses the subject area.

The final four columns of Table 1 indicate the categories of FMPs to which the standard would apply. The FMPs are categorized by the amount of flow they measure on a monthly basis as follows: ''M'' is marginal-volume, ''L'' is low-volume, ''H'' is high-volume, and ''V'' is very-high volume. Definitions for these various classifications are included in the definitions section in proposed § 3175.10. An ''x'' in a column indicates that the standard listed applies to that category of FMP. A number in a column indicates a numeric value for that category, such as the maximum number of months or years between inspections and is explained in the body of the proposed standard. The requirements of the proposed rule would vary depending on the average monthly flow rate being measured. In general, the higher the flow rate, the greater the risk of mis-measurement, and the stricter the requirements would be.

Proposed § 3175.80 would adopt API MPMS 14.3.1.4.1, which sets out requirements for the fluid and flowing conditions that must exist at the FMP (*i.e.,* single phase, steady state, Newtonian, and Reynolds number greater than 4,000). The first three of these conditions do not represent a change from Order 5, which incorporates the 1985 AGA Report No. 3. The term ''single-phase'' means that the fluid flowing through the meter consists only of gas. Any liquids in the flowing stream will cause measurement error. The requirement for single-phase fluid in the proposed rule is the same as the requirement for fluid of a homogenous state in AGA Report No. 3 (1985), paragraph 14.3.5.1. The term ''steady-state'' means that the flow rate is not changing rapidly with time. Pulsating flow that may exist downstream of a piston compressor is an example of non-steady-state flow because the flow rate is changing rapidly with time. Pulsating or non-steady-state flow will also cause measurement error. The requirement for steady-state flow in the proposed rule is essentially the same as the requirement to suppress pulsation in the AGA Report No. 3 (1985), paragraph 14.3.4.10.3. The term ''Newtonian fluid'' refers to a fluid whose viscosity does not change with flow rate. The requirement for Newtonian fluids in the proposed rule is not specifically stated in the AGA Report No. 3 (1985); however, all gases are generally considered Newtonian fluids. Therefore, this does not represent a change in requirements.

The proposed requirement for maintaining a Reynolds number greater than 4,000 represents a change from Order 5. Order 5 does not have a requirement for a minimum Reynolds number. The Reynolds number is a measure of how turbulent the flow is. Rather than expressed in units of measurement, the Reynolds number is the ratio of inertial forces (flow rate, relative density, and pipe size) to viscous forces. The higher the flow rate, relative density, or pipe size, the higher the Reynolds number. High viscosity, on the other hand, acts to lower the Reynolds number. At a Reynolds number below 2,000, fluid movement is controlled by viscosity and the fluid molecules tend to flow in straight lines parallel to the direction of flow (generally referred to as laminar flow). At a Reynolds number above 4,000, fluid movement is controlled by inertial forces, with molecules moving chaotically as they collide with other molecules and with the walls of the pipe (generally referred to as turbulent flow). Fluid behavior between a Reynolds number of 2,000 and 4,000 is difficult to predict. For all meters using the principle of differential pressure, including orifice meters, the flow equation assumes turbulent flow with a Reynolds number greater than 4,000.

Using a typical gas viscosity of 0.0103 centipoise and 0.7 relative density, a Reynolds number of 4,000 is achieved at a flow rate of 5.8 thousand standard cubic feet per day (Mcf/day) in a 2-inch diameter pipe, 8.7 Mcf/day in a 3-inch diameter pipe, and 11.6 Mcf/day in a 4-inch diameter pipe. The majority of pipe sizes currently used at FMPs are between 2 inches and 4 inches in diameter. Because low-, high-, and very-high volume FMPs all exceed 15 Mcf/day by definition, most FMPs within these categories and with line sizes of 4 inches or less, would operate at Reynolds numbers well above 4,000. Marginal-volume FMPs would be exempt from this requirement. Therefore, adoption of the proposed requirement to maintain a Reynolds number greater than 4,000 would not represent a significant change from existing conditions. The proposed requirement for maintaining a Reynolds number greater than 4,000 for low-, high-, and very-high volume FMPs would help ensure the accuracy of measurement in rare situations where the pipe size is greater than 4 inches or flowing conditions are significantly different from the conditions used in the examples above.

Marginal-volume FMPs could fall below this limit, but would be exempt from the Reynolds number requirement. While the BLM recognizes that measurement error could occur at FMPs with Reynolds numbers below 4,000, it would be uneconomic to require a different type of meter to be installed at marginal-volume FMPs. The BLM recognizes that not maintaining the fluid and flowing conditions recommended by API can cause significant measurement error. However, the measurement error at such low flow rates would not significantly affect royalty, and the potential error in royalty is small compared to the potential loss of royalty if production were shut in.

Proposed § 3175.80 would adopt API MPMS 14.3.2.4, which establishes requirements for orifice plate construction and condition. Orifice plate standards adopted would be virtually the same as they are in the AGA Report No. 3 (1985). No exemptions to this requirement are proposed, since the cost of obtaining compliant orifice plates for most sizes used at FMPs (2-inch, 3-inch, and 4-inch) is minimal and orifice plates not complying with the API standards can cause significant bias in measurement. Therefore, the BLM proposes to incorporate API MPMS 14.3.2.4.

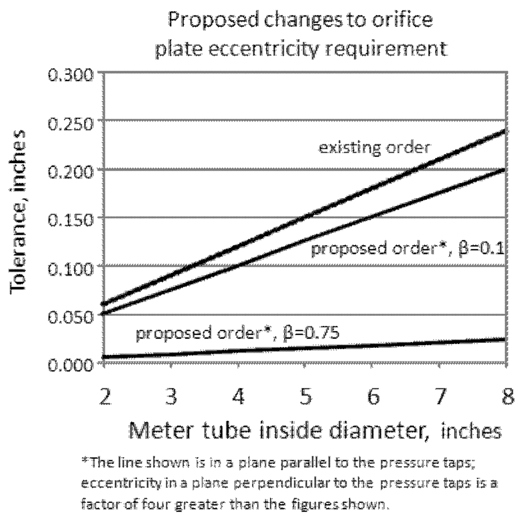

Figure 2

Proposed § 3175.80 would adopt API MPMS 14.3.2.6.2 regarding orifice plate eccentricity and perpendicularity. The term ''eccentricity'' refers to the centering of the orifice plate in the meter tube and ''perpendicularity'' refers to the alignment of the orifice plate with respect to the axis of the meter tube. This represents a change from the existing requirements in AGA Report Number 3 (1985), since the eccentricity tolerances are significantly smaller in the new API standard proposed for incorporation, and will reduce the uncertainty of measurement. Eccentricity can affect the flow profile of the gas through the orifice and larger Beta ratio [3] meters (*i.e.,* meters with larger diameter orifice bores relative to the diameter of the meter tube) are more sensitive to flow profile than smaller Beta ratio meters. For that reason, larger Beta ratio meters have a smaller eccentricity tolerance (see Figure 2). However, the BLM does not believe based on its experience in the field that this proposed change would impose significant costs on operators because many new and existing meter installations use specially designed orifice plate holders that meet the new tolerances. Some ''flange-fitting'' installations may have to be retrofitted with alignment pins or other devices to meet the tighter tolerances. The BLM is asking for data on the cost of this retrofit and on the number of meters that it may affect.

The proposed section also incorporates a requirement for the orifice plate to be installed perpendicular to the meter tube axis as required by API MPMS 14.3.2.6.2.2. This requirement is not explicitly stated in Order 5. However, virtually all orifice plate holders, new and existing, maintain perpendicularity between the orifice plate and the meter-tube axis. Therefore, the BLM does not anticipate that this proposed change would impose significant costs.

Proposed § 3175.80(a) would redefine the allowable Beta ratio range for flange-tapped orifice meters to be between 0.10 and 0.75, as recommended by API MPMS 14.3.2. Order 5 established Beta ratio limits of 0.15 and 0.70 for meters measuring more than 100 Mcf/day. These limits were based on AGA Report No. 3 (1985), which was the orifice metering standard in effect at the time Order 5 was published. In the early 1990s, additional testing was done on orifice meters, which resulted in an increased Beta ratio range and a more accurate characterization of the uncertainty of orifice meters over this range. The testing also showed that a meter with a Beta ratio less than 0.10 could result in higher uncertainty due to the increased sensitivity of upstream edge sharpness. Meters with Beta ratios greater than 0.75 exhibited increased uncertainty due to flow profile sensitivity. Because this rule would propose to expand the allowable Beta ratio range, it would be slightly less restrictive than Order 5 for high-volume and very-high-volume FMPs.

This section would also apply the Beta ratio limits to low-volume FMPs, which would be a change from Order 5. Order 5 exempts meters measuring 100 Mcf/day or less from the Beta ratio limits. We know of no data showing that bias is not significant for Beta ratios less than 0.10. Generally, if edge sharpness cannot be maintained, it results in a measurement that is biased to the low side. The low limit for the Beta ratio in API MPMS 14.3.2 is based on the inability to maintain edge sharpness in Beta ratios below 0.10. Therefore, there is a potential for bias if the BLM were to allow Beta ratios lower than 0.10. Because the proposed rule would allow Beta ratios as low as 0.10, and Beta ratios less than 0.10 are relatively rare, this change would not be significant.

While the increased sensitivity to flow profile due to Beta ratios greater than 0.75 does not generally result in bias (only an increase in uncertainty), this section also proposes to maintain the upper Beta ratio limit in API MPMS 14.3.2 for low-volume FMPs. It is very rare for an operator to install a large Beta ratio orifice plate on low-volume meters, so the 0.75 upper Beta ratio limit for low-volume FMPs would not be a significant change either.

Marginal-volume FMPs would be exempt from any Beta ratio restrictions in the proposed rule because it can be difficult to obtain a measureable amount of differential pressure with a Beta ratio of 0.10 or greater at very low flow rates. The increased uncertainty and potential for bias by allowing a Beta ratio less than 0.10 on marginal-volume FMPs is offset by the ability to accurately measure a differential pressure and record flow.

Proposed § 3175.80(b) would establish a minimum orifice bore diameter of 0.45 inches for high-volume and very-high-volume FMPs. This would be a new requirement. API MPMS 14.3.1.12.4.1 states: ''Orifice plates with bore diameters less than 0.45 inches . . . may have coefficient of discharge uncertainties as great as 3.0 percent. This large uncertainty is due to problems with edge sharpness.'' Because the uncertainty of orifice plates

[3] Beta ratio is the ratio of the orifice plate bore to the inside diameter of the meter tube

less than 0.45 inches in diameter has not been specifically determined, the BLM cannot mathematically account for it when calculating overall measurement uncertainty under proposed § 3175.30(a). To ensure that high-volume and very-high-volume FMPs maintain the uncertainty required in proposed § 3175.30(a), the BLM is proposing to prohibit the use of orifice plates with bores less than 0.45 inches in diameter. Because there is no evidence to suggest that the use of orifice plates smaller than 0.45 inches in diameter causes measurement bias in low-volume and marginal-volume FMPs, they would be allowed for use in these FMPs.

Proposed § 3175.80(c) would require bi-weekly orifice plate inspections for FMPs measuring production from wells first coming into production, which would be a new requirement. It is common for new wells to produce high amounts of sand, grit, and other particulate matter for some initial period of time. This material can quickly damage an orifice plate, generally causing measurement to be biased low. The proposed requirement would increase the orifice plate inspection frequency until it could be demonstrated that the production of particulate matter from a new well first coming into production has subsided. The bi-weekly inspection requirement would apply to existing FMPs already measuring production from one or more other wells through which gas from a new well first coming into production is measured.

Under this proposed rule, once a bi-weekly inspection demonstrates that no detectable wear occurred over the previous 2 weeks, the BLM would consider the well production to have stabilized and the inspection frequency would revert to the frequency proposed in Table 1. There would be no exemptions proposed for this requirement because: (1) Based on the BLM's experience, pulling and inspecting an orifice plate generally takes less than 30 minutes and is a low-cost operation; and (2) In most cases the new requirement would not apply to marginal wells anyway because rarely would a newly-drilled well have only marginal levels of gas production.

Proposed § 3175.80(d) would establish a frequency for routine orifice plate inspections. The term ''routine'' is used to differentiate this proposed requirement from proposed § 3175.80(c) of this rule for new FMPs measuring production from new wells. Under this rule, the proposed inspection frequency would depend on the average flow rate measured by the FMP. The required inspection frequency, in months, is given in Table 1. More than any other component of the metering system, orifice plate condition has one of the highest potentials to introduce measurement bias and create error in royalty calculations. The higher the flow rate being measured, the greater the risk to ongoing measurement accuracy. Therefore, the higher the flow rate, the more often orifice plate inspections would be required. Order 5 requires orifice plates to be pulled and inspected every 6 months, regardless of the flow rate. For high-volume and very-high-volume FMPs, this proposal would increase the frequency of orifice plate inspections to every 3 months and every month, respectively. For marginal-volume FMPs, the proposed frequency would be reduced to every 12 months, and for low-volume FMPs there would be no change from the existing inspection frequency of every 6 months. Order 5 also requires that an orifice plate inspection take place during the calibration of the secondary device. This requirement would be retained in the proposed rule.

Proposed § 3175.80(e) would require the operator to document the condition of an orifice plate that is removed and inspected. Documentation of the plate inspection can be a useful part of an audit trail and can also be used to detect and track metering problems. Although this would be a new requirement, many meter operators already record this information as part of their meter calibrations. Thus, this requirement would not be a significant change from prevailing industry practice.

Proposed § 3175.80(f) would require meter tubes to be constructed in compliance with current API standards. This proposed requirement would not include meter tube lengths, which would be addressed in proposed § 3175.80(k). The BLM has reviewed the API standards referenced and believes that they meet the intent of § 3175.30 of the proposed rule. Order 5 adopted the meter tube construction standards of the AGA Report No. 3 (1985). A comparison of meter tube construction requirements between the proposed rule and Order 5 is outlined in the following table. The term ''Potentially'' as used in the table means that a retrofit could be required if the existing meter tube did not meet the requirements of API MPMS 14.3.2. It is possible, for example, that a meter tube constructed before 2000 could still meet the roughness and roundness standards in API MPMS 14.3.2.

Parameter	Proposed (API 14.3.2, 2000)	Existing (AGA Report No. 3, 1985)	Require retrofit?
Surface roughness (R_a)	$\beta \geq 0.6$: 34 μin $\leq R_a <$ 250 μin $\beta < 0.6$: 34 μin $\leq R_a <$ 300 μin	$R_a \leq$ 300 μin	No
Meter tube diameter	Average of 4 measurements 1 inch upstream of orifice.	Average of 4 measurements 1 inch upstream of orifice.	No
Upstream check measurements.	2 additional cross sections	2 additional cross sections	No.
Downstream check measurements.	At 1 inch downstream of the orifice	At 1 inch downstream of the orifice	No.
Roundness at inlet section	Difference between any measurement and the average diameter ≤ 0.25% of average diameter.	Difference between maximum and minimum measurement ≤ 0.5% to 5% of average diameter as a function of β.	Potentially.
Roundness at all upstream sections.	Difference between maximum and minimum ≤ 0.5% of average diameter.	Not specified	Potentially.
Roundness at downstream section.	Difference between any measurement and the average diameter ≤ 0.5% of average diameter.	Difference between any measurement and the average diameter ≤ 0.5% to 5% of average diameter as a function of β.	Potentially.
Abrupt changes	Not allowed	Not allowed	No.
Gaskets, protrusions, recesses	Protrusions prohibited; recesses restricted if > 0.25 inches.	Recesses restricted if > 0.25 inches	No.

Parameter	Proposed (API 14.3.2, 2000)	Existing (AGA Report No. 3, 1985)	Require retrofit?
Tap hole location	1 inch from upstream and downstream orifice plate faces, respectively.	1 inch from upstream and downstream orifice plate faces, respectively.	No.
Tap hole location tolerance	Range from 0.015 inches to 0.15 inches depending on size and β.	Range from 0.015 inches to 0.15 inches depending on size and β.	No.
Tap hole diameter	0.375 ±0.016 inches (2–3 inch nominal diameter); 0.500 ±0.016 inches (4 inch and greater nominal diameter).	0.250 to 0.375 inches (2–3 inch nominal diameter); 0.250 to 0.500 inches (4 inch and greater nominal diameter).	No (holes can be re-drilled).

NOTE: β = the Beta ratio; μin = micro-inches (millionth of an inch) R_a = average roughness of surface finish of the orifice plate

The primary difference in meter tube requirements between Order 5 and the proposed rule is the roundness specifications for the meter tube at upstream and downstream locations. The orifice plate uncertainty specifications given in API MPMS 14.3.1 are based on the tighter roundness tolerances proposed in this rule. The roundness specifications in the AGA Report No. 3 (1985) would increase the uncertainty by an unknown amount. However, there is no existing evidence that bias results from a less round pipe, as allowed in the AGA Report No. 3 (1985).

Uncertainty is the risk of mismeasurement; in contrast, bias necessarily results in mismeasurement. For example, an uncertainty of plus or minus 3 percent means that the meter could be reading anywhere between 3 percent low and 3 percent high. On the other hand, a bias of plus 3 percent means the meter is reading 3 percent high. This rule proposes to restrict the amount of allowable risk or uncertainty of measurement in high-volume and very-high-volume meters. To do so, however, the BLM must be able to quantify the individual sources of uncertainty that go into the calculation of overall measurement uncertainty. This rule also proposes to eliminate statistically significant bias in all FMPs other than marginal-volume FMPs.

Proposed § 3175.80(f)(1) and (2) would include an exception allowing low-volume FMPs to continue using the tolerances in the AGA Report No (1985). While the BLM recognizes this could result in higher uncertainty, we are not proposing uncertainty requirements for low-volume FMPs. Since the AGA Report No. 3 (1985) is no longer readily available to the public, and cannot be incorporated by reference, this proposed rule includes an equation in proposed § 3175.80(f)(1) that approximates the roundness tolerance graph in the AGA Report No. 3 (1985).

Marginal FMPs would not be required to meet the construction standards of either API MPMS 14.3.2 (2000) or the 1985 Report No. 3 (AGA), since the cost to bring these meters up to the appropriate standards could be prohibitive based on experience with these production levels.

Proposed § 3175.80(g) would address isolating flow conditioners and tube bundle flow straighteners. To achieve the orifice plate uncertainty stated in API MPMS 14.3.1, the gas flow approaching the orifice plate must be free of swirl and asymmetry. This can be achieved by placing a section of straight pipe between the orifice plate and any upstream flow disturbances such as elbows, tees, and valves. Swirl and asymmetry caused by these disturbances will eventually dissipate if the pipe lengths are long enough. The minimum length of pipe required to achieve the uncertainty stated in API MPMS 14.3.1 is discussed in proposed § 3178.80(k).

Isolating flow conditioners and tube-bundle flow straighteners are designed to reduce the length of straight pipe upstream of an orifice meter by accelerating the dissipation of swirl and asymmetric flow caused by upstream disturbances. Both devices are placed inside the meter tube at a specified distance upstream of the orifice plate. An isolating flow conditioner consists of a flat plate with holes drilled through it in a geometric pattern designed to reduce swirl and asymmetry in the gas flow. A tube bundle is a collection of tubes that are welded together to form a bundle.

Proposed § 3175.80(g) would allow isolating flow conditioners to be used at FMPs if they have been reviewed and approved by the BLM under § 3175.46 of the proposed rule. Isolating flow conditioners are not addressed in Order 5 and currently must be approved on a meter-by-meter basis using the variance process. The approval of isolating flow conditioners in the proposed rule would increase consistency and eliminate the time and expense it takes to apply for and obtain a variance for each FMP.

Proposed § 3175.80(g) would adopt API MPMS 14.3.2.5.5.1 through 14.3.2.5.5.3 regarding the construction of 19-tube-bundle flow straighteners used for flow conditioning. Use of 19-tube-bundle flow straighteners constructed and installed under these API standards would not require BLM approval. Under Order 5, a minimum of four tubes were required in a tube-bundle flow straightener. The proposed rule would require a tube-bundle flow straightener, if used, to consist of 19 tubes because all of the findings in API MPMS 14.3.2.5.5.1 through 14.3.2.5.5.3 are based on 19-tube flow straighteners. Adoption of the proposed rule would prohibit the use of 7-tube-bundle flow straighteners, which are used primarily in 2-inch meters. Additionally, 19-tube-bundle flow straighteners are typically not available in a 2-inch size for these existing meters. A significant number of the meters in use currently are 2-inch in size. Without the ability to use either 7-tube- or 19-tube-bundle flow straighteners, 2-inch meters would be required to be retrofitted to use either: (1) A proprietary type of isolating flow conditioner approved in accordance with proposed § 3175.46; or (2) No flow conditioner, typically requiring much longer lengths of pipe upstream of the orifice plate. Marginal-volume FMPs are proposed to be exempt from the requirement to retrofit because the costs involved are believed to outweigh the benefits based upon experience with these production levels.

Proposed § 3175.80(h) would require an internal visual inspection of all meter tubes at the frequency, in years, shown in Table 1. The visual inspection would have to be conducted using a borescope or similar device (which would obviate the need to remove or disassemble the meter run), unless the operator decided to disassemble the meter run to conduct a detailed inspection, which also would meet the requirements of this proposed paragraph. While an inspection using a borescope or similar device cannot ensure that the meter tube complies with API 14.3.2 requirements, it can identify issues such as pitting, scaling, and buildup of foreign substances that could warrant a detailed inspection under § 3175.80(i) of this proposed rule.

Proposed § 3175.80(i) would require a detailed inspection of meter tubes on high- and very-high-volume FMPs at the frequency, in years, shown in Table 1 (10 years for high-volume FMPs and 5 years for very-high-volume FMPs). The AO could increase this frequency, and could require a detailed inspection of low-volume FMPs, if the visual inspection identified any issues regarding compliance with incorporated API standards, or if the meter tube operates in adverse conditions (such as corrosive or erosive gas flow), or has signs of physical damage. The goal of the inspection is to determine whether the meter is in compliance with required standards for meter-tube construction. Meter tube inspection would be required more frequently for very-high-volume FMPs because there is a higher risk of volume errors and, therefore, royalty errors in higher-volume FMPs. Marginal-volume FMPs would be exempt from the inspection requirement because they would be exempt from the construction standards of API MPMS 14.3.2.

Proposed § 3175.80(j) would require operators to keep documentation of all meter tube inspections performed. The BLM would use this documentation to establish that the inspections met the requirements of the rule, for auditing purposes, and to track the rate of change in meter tube condition to support a change of inspection frequency, if needed. Marginal-volume FMPs would be exempt from this requirement because no meter tube inspections are required.

Proposed § 3175.80(k) would establish requirements for the length of meter tubes upstream and downstream of the orifice plate, and for the location of tube-bundle flow straighteners, if they are used (see discussion of swirl and asymmetry in § 3175.80(g)). Marginal-volume FMPs are proposed to be exempt from the meter tube length requirements because the costs involved in retrofitting the meter tubes are believed to outweigh the benefits based on experience with these production levels.

The pipe length requirements in AGA Report No. 3 (1985) (incorporated by reference in Order 5) were based on orifice plate testing done before 1985. In the early 1990s, extensive additional testing was done to refine the uncertainty and performance of orifice plate meters. This testing revealed that the recommended pipe lengths in the AGA Report No. 3 (1985) were generally too short to achieve the stated uncertainty levels. In addition, the testing revealed that tube bundles placed in accordance with the 1985 AGA Report No. 3 could bias the measured flow rate by several percent.

When API MPMS 14.3.1 was published in 2000, it used the additional test data to revise the meter tube length and tube-bundle location requirements to achieve the stated levels of uncertainty and remove bias. All meter tubes installed after the publication of API MPMS 14.3.2 should already comply with the more stringent requirements for meter tube length and tube-bundle placement.

Because the meter tube lengths in API MPMS 14.3.2 are required to achieve the stated uncertainty, paragraph (k)(1) proposes to adopt these lengths as a minimum standard for high-volume and very-high-volume FMPs. Due to the high production decline rates in many Federal and Indian wells, the BLM does not expect a significant number of meters that were installed prior to 2000, under the AGA Report No. 3 (1985) standards, to still be measuring gas flow rates that would place them in the high-volume or very-high-volume categories. Most high-volume and very-high-volume FMPs were installed after 2000, in compliance with the meter tube length requirements of API MPMS 14.3.2. Therefore, the proposed requirement is not a significant change from existing conditions.

While low-volume FMPs would not be subject to the uncertainty requirements under proposed § 3175.30(a), they still would have to be free of statistically significant bias under proposed § 3175.30(c). Because testing has shown that placement of tube-bundle flow straighteners in conformance with the AGA Report No. 3 (1985) can cause bias, low-volume FMPs utilizing tube-bundle flow straighteners would also be subject to the meter tube length requirements of API MPMS 14.3.2 under proposed paragraph (k)(1).

While this may require some retrofitting of existing meters, the BLM does not expect this to be a significant change for three reasons. First, FMPs installed after 2000 should already comply with the meter tube length and tube-bundle placement requirements of API MPMS 14.3.2. Second, based on the BLM's experience, we estimate that fewer than 25 percent of existing meters use tube-bundle flow straighteners. Third, for those FMPs that would need to be retrofitted, most operators would opt to remove the tube-bundle-flow straightener and replace it with an isolating flow conditioner. Several manufacturers make a type of isolating flow conditioner designed to replace tube bundles without retrofitting the upstream piping. These flow conditioners are relatively inexpensive and would not create an economic burden on the operator for low-volume FMPs.

Proposed paragraph (k)(2) would allow low-volume FMPs that do not have tube-bundle flow straighteners to comply with the less stringent meter tube length requirements of the AGA Report No. 3 (1985). For those meter tubes that do not include tube-bundle flow straighteners, the BLM is not currently aware of any data that shows the shorter meter tube lengths required in the AGA Report No. 3 (1985) result in statistically significant bias. Since the AGA Report No. 3 (1985) is no longer readily available to the public, and cannot be incorporated by reference, this section includes equations that approximate the meter tube length graphs in the AGA Report (1985), Figures 4–8.

Proposed § 3175.80(l) would set standards for thermometer wells, including the adoption of API MPMS 14.3.2.6.5 in proposed § 3175.80(l)(1). While the provisions of the API standard proposed for adoption in the proposed rule are the same as those in the AGA Report No. 3 (1985), several additional items would be added that constitute a change from Order 5. First, proposed § 3175.80(l)(2) would require operators to install the thermometer well in the same ambient conditions as the primary device. The purpose of measuring temperature is to determine the density of the gas at the primary device, which is used in the calculation of flow rate and volume. A 10-degree error in the measured temperature will cause a 1 percent error in the measured flow rate and volume. Even if the thermometer well is located away from the primary device within the distances allowed by API MPMS 14.3.2.6.5, significant temperature measurement error could occur if the ambient conditions at the thermometer well are different. For example, if the orifice plate is located inside of a heated meter house and the thermometer well is located outside of the heated meter house, the measured temperature will be influenced by the ambient temperature, thereby biasing the calculated flow rate. In these situations, the proposed rule would require the thermometer well to be relocated inside of the heated meter house even if the existing location is in compliance with API MPMS 14.3.2.6.5.

Proposed § 3175.80(l)(3) would apply when multiple thermometer wells exist at one meter. Many meter installations include a primary thermometer well for continuous measurement of gas temperature and a test thermometer well, where a certified test thermometer is inserted to verify the accuracy of the primary thermometer. API does not specify which thermometer well should be used as the primary thermometer. To minimize measurement bias, the gas temperature should be taken as close to the orifice plate as possible. When more than one thermometer well exists, the thermometer well closest to the orifice will generally result in less measurement bias; and therefore, the proposed rule would specify that this thermometer well is the one that must be used for primary temperature measurement.

Proposed § 3175.80(l)(4) would require the use of a thermally conductive fluid in a thermometer well. To ensure that the temperature sensed by the thermometer is representative of the gas temperature at the orifice plate, it is important that the thermometer is thermally connected to the gas. Because air is a poor heat conductor, the proposed rule would include a new requirement that a thermally conductive liquid be used in the thermometer well because this would provide a more accurate temperature measurement.

Marginal-volume FMPs would be exempt from the requirement to have thermometer wells because proposed §§ 3175.91(c) and 3175.101(e) would allow operators to estimate flowing temperature in lieu of a temperature measurement for marginal-volume FMPs. Order 5 exempts meters measuring less than 200 Mcf/day from continuous temperature measurement; however, the only alternative to continuous measurement allowed in Order 5 is instantaneous measurement, which still requires a thermometer well. Therefore, the proposed requirement for low-volume, high-volume, and very-high-volume FMPs to have a thermometer well would not constitute a significant change from Order 5.

Proposed § 3175.80(m) would require operators to locate the sample probe as required in § 3175.112(b). This would be a new requirement. The reference to proposed § 3175.112(b) is in proposed § 3175.80(m) because the sample probe is part of the primary device. Please see the discussion of proposed § 3175.112(b) for an explanation of the requirement.

Proposed § 3175.80(n) would include a new requirement for operators to notify the BLM at least 72 hours in advance of a visual or detailed meter-tube inspection or installation of a new meter tube. Because meter tubes are inspected infrequently, it is important that the BLM be given an opportunity to witness the inspection of existing meter tubes or the installation of new meter tubes. Order 5 does not require meter tube inspection. Because meter tube inspections would not be required for marginal FMPs, they would be exempt from this requirement.

§ 3175.90 Mechanical Recorders (Secondary Device)

Proposed § 3175.90(a) would limit the use of mechanical recorders, also known as chart recorders, to marginal-volume and low-volume FMPs, which would be a change from Order 5. Mechanical recorders would not be allowed at high-volume and very-high-volume FMPs because they may not be able to meet the uncertainty requirements of proposed § 3175.30(a). Mechanical recorders are subject to many of the same uncertainty sources as EGM systems, such as ambient temperature effects, vibration effects, static pressure effects, and drift. In addition, mechanical recorders are vulnerable to other sources of uncertainty such as paper expansion and contraction effects and integration uncertainty. Unlike EGM systems, however, none of these effects have been quantified for mechanical recorders. All of these factors contribute to increased uncertainty and the potential for inaccurate measurement.

Because there is no data which indicate that the use of mechanical recorders results in statistically significant bias, mechanical recorders are proposed to be allowed at low-volume and marginal-volume FMPs due to the limited production from these facilities.

Table 2 was developed as part of proposed § 3175.90 to clarify and provide easy reference to the requirements that would apply to different aspects of mechanical recorders. No industry standards are cited in Table 2 because there are no industry standards applicable to mechanical recorders. The first column of Table 2 lists the subject of the standard. The second column of Table 2 contains a reference to the section and specific paragraph in the proposed rule for the standard that applies to each subject area. (The standards are prescribed in proposed §§ 3175.91 and 3175.92.)

The final two columns of Table 2 indicate the FMPs to which the standard would apply. The FMPs are categorized by the amount of flow they measure on a monthly basis as follows: ''M'' is marginal-volume FMP and ''L'' is low-volume FMP. As noted previously, mechanical recorders would not be allowed at high-volume and very-high-volume FMPs; therefore, the table in this section does not include corresponding columns for them. Definitions for the various FMP categories are given in proposed § 3175.10. An ''x'' in a column indicates that the standard listed applies to that category of FMP. A number in a column indicates a numeric value for that category, such as the maximum number of months or years between inspections, which is explained in the body of the proposed requirement.

§ 3175.91 Installation and Operation of Mechanical Recorders

Proposed § 3175.91(a) would set requirements for gauge lines, which Order 5 does not address. Gauge lines connect the pressure taps on the primary device to the mechanical recorder and can contribute to bias and uncertainty if not properly designed and installed. For example, a leaking or improperly sloped gauge line could cause significant bias in the differential pressure and static pressure readings. Improperly installed gauge lines can also result in a phenomenon known as ''gauge line error'' which tends to bias measured flow rate and volume. This is discussed in more detail below.

The proposed requirement in § 3175.91(a)(1) would require a minimum gauge line inside diameter of 0.375'' to reduce frictional effects that could result from smaller diameter gauge lines. These frictional effects could dampen pressure changes received by the recorder which could result in measurement error.

Proposed § 3175.91(a)(2) would allow only stainless-steel gauge lines. Carbon steel, copper, plastic tubing, or other material could corrode and leak, thus presenting a safety issue as well as resulting in biased measurement.

Proposed § 3175.91(a)(3) would require gauge lines to be sloped up and away from the meter tube to allow any condensed liquids to drain back into the meter tube. A build-up of liquids in the gauge lines could significantly bias the differential pressure reading.

Proposed requirements in § 3175.91(a)(4) through (7) are intended to reduce a phenomenon known as ''gauge line error,'' which is caused when changes in differential or static pressure due to pulsating flow are amplified by the gauge lines, thereby causing increased bias and uncertainty. API MPMS 14.3.2.5.4.3 recommends that gauge lines be the same diameter along their entire length, which would be adopted as a minimum standard in proposed paragraph (a)(4).

Proposed §§ 3175.91(a)(5) and (6) are intended to minimize the volume of gas contained in the gauge lines because excessive volume can contribute significantly to gauge-line error whenever pulsation exists. These proposed paragraphs would allow only the static-pressure connection in a gauge line and would prohibit the practice of connecting multiple secondary devices to a single set of pressure taps, the use of drip pots, and the use of gauge lines as a source for pressure-regulated control valves, heaters, and other equipment. § 3175.91(a)(7) proposes to limit the gauge lines to 6 feet in length, again to minimize the gas contained in the gauge lines.

Marginal-volume FMPs would be exempt from the requirements of proposed § 3175.91(a) because any bias or uncertainty caused by improperly designed gauge lines of marginal-volume and low-volume FMPs would not have a significant royalty impact.

Proposed § 3175.91(b) would require that all differential pens record at a minimum of 10 percent of the chart range for the majority of the flowing period. This would be a change from Order 5, which has no requirements for the differential pen position for meters measuring 100 Mcf/day or less on a monthly basis. However, the integration of the differential pen when operating very close to the chart hub can cause substantial bias because a small amount of differential pressure could be interpreted as zero, thereby biasing the volume represented by the chart. A reading of at least 10 percent of the chart range will provide adequate separation of the differential pen from the ''zero'' line while still allowing flexibility for plunger lift operations that operate over a large range. Marginal-volume FMPs would be exempt from this requirement due to the cost associated with compliance.

The proposed rule would eliminate the current requirement in Order 5 that the static pen operate in the outer 2/3 of the chart range for the majority of the flowing period, regardless of flow rate. The primary purpose of this requirement in Order 5 was to reduce measurement uncertainty caused by the operation of the static pen near the hub. However, because proposed § 3175.30(a) would exempt marginal-volume and low-volume FMPs from uncertainty limitations, this requirement would no longer be necessary thereby relieving an operational burden at these FMPs.

Proposed § 3175.91(c) would require the flowing temperature to be continuously recorded for low-volume FMPs. Flowing temperature is needed to determine flowing gas density, which is critical to determining flow rate and volume. Order 5 requires continuous temperature measurement only for meters measuring more than 200 Mcf/day. For meters flowing 200 Mcf/day or less, the use of an indicating thermometer is allowed under Order 5. Typically, an indicating thermometer is inserted into the thermometer well during a chart change. That instantaneous value of flowing temperature is used to calculate volume for the chart period. This introduces a significant potential bias into the calculations. If, for example, the temperature is always obtained early in the morning, then the flowing temperature used in the calculations will be biased low from the true average value due to lower morning ambient temperatures. A continuous temperature recorder is used to obtain the true average flowing temperature over the chart period with no significant bias. Because proposed § 3175.30(c) would prohibit bias that is statistically significant for low-volume FMPs, we propose applying the requirement for continuous recorders to low-volume FMPs, but not to marginal-volume FMPs, as specified in Table 2.

Proposed § 3175.91(d) would require certain information to be available on-site at the FMP and available to the AO at all times. This requirement would allow the BLM to calculate the average flow rate indicated by the chart and to verify compliance with this rule. The information that would be required under proposed § 3175.91(d)(2), (3), (7), and (8) is not required under Order 5, but typically is already available on-site. For example, the static pressure and temperature element ranges are stamped into the elements and are visible to BLM inspectors, and the meter-tube inside diameter is typically stamped into the downstream flange or is on a tag as part of the device holder, making it visible and available to the BLM. Therefore, because this information is typically already available on site, the proposed requirement would not be a significant change from current industry practice.

The information that the operator would have to retain on-site at the FMP under proposed § 3175.91(d)(1), (4), (5), (6), (9), (10), (11), (12), and (13) is not currently required and thus typically has not been maintained on-site as a matter of practice. This proposed requirement therefore represents a change from Order 5. The required information proposed in these paragraphs includes the differential pressure bellows range, the relative density of the gas, the units of measure for static pressure (psia or psig), the meter elevation, the orifice bore diameter, the type and location of flow conditioner, the date of the last orifice plate inspection, and the date of the last meter verification. The BLM is proposing to require this information to be maintained on-site to enable the AO to determine if the meter is operating in compliance with this proposed rule and to determine the reasonableness of reported volume.

Proposed § 3175.91(e) would require the differential pressure, static pressure, and temperature elements to be operated within the range of the respective elements. Operating any of the elements beyond the upper range of the element will cause the pen to record off the chart. When a chart is integrated to determine volume, any parameters recorded off the chart will not be accounted for, which results in biased measurement. Although this would be a new requirement, operating a mechanical recorder within the range of the elements is common industry practice and would not constitute a significant change.

§ 3175.92 Verification and Calibration of Mechanical Recorders

Proposed § 3175.92(a) would set requirements for the verification and calibration of mechanical recorders upon installation or after repairs, and would define the procedures that operators would be required to follow. Order 5 also requires a verification of mechanical recorders upon installation or after repairs. This proposal would be a minor change to Order 5 requirements because the proposed rule differentiates the procedures that are specific to this type of verification from a routine verification that would be required under § 3175.92(b) of the proposed rule.

Proposed § 3175.92(a)(1) would require the operator to perform a successful leak test before starting the mechanical recorder verification. While the requirement for a leak test is in Order 5, the proposed rule would specify the tests that operators would have to perform. We are proposing this level of specificity because it is possible to perform leak tests without ensuring that all valves, connections, and fittings are not leaking. Leak testing is necessary because a verification or calibration done while valves are leaking could result in significant meter bias. A provision would also be added to this section requiring a successful leak test to precede a verification. This is implied in Order 5, but not explicitly stated.

Proposed § 3175.92(a)(2) would require that the differential- and static-pressure pens operate independently of each other, which is accomplished by adjusting the time lag between the pens. Although Order 5 includes a requirement for a time-lag test, the specific amount of required time lag would be new to this proposed rule. Examples of appropriate time lag are given for a 24-hour chart and an 8-day chart because these are the charts that are normally used as test charts for verification and calibration.

Proposed § 3175.92(a)(3) would require a test of the differential pen arc. This is the same as the requirement Order 5.

Proposed § 3175.92(a)(4) would require an ''as left'' verification to be done at zero percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the differential and static element ranges. This would be a change from Order 5, which only requires a verification at zero and 100 percent of the element range and the normal operating position of the pens. The additional verification points would help ensure that the pens have been properly calibrated to read accurately throughout the element ranges. This section also clarifies the verification of static pressure when the static pressure pen has been offset to include atmospheric pressure. In this case, the element range is assumed to be in pounds per square inch, absolute (psia) instead of pounds per square inch, gauge (psig). For example, if the static pressure element range is 100 psig and the atmospheric pressure at the meter is 14 psia, then the calibrator would apply 86 psig to test the ''100 percent'' reading as required in proposed § 3175. 92(a)(4)(iii). This prevents the pen from being pushed off the chart during verification. As-found readings are not required in this section because as-found readings would not be available for a newly installed or repaired recorder.

Proposed § 3175.92(a)(5) would require a verification of the temperature element to be done at approximately 10 °F below the lowest expected flowing temperature, approximately 10 °F above the highest expected flowing temperature, and at the expected average flowing temperature. This would be a change from Order 5, which has no requirements for verification of the temperature element. This requirement would ensure that the temperature element is recording accurately over the range of expected flowing temperature.

Proposed § 3175.92(a)(6) would establish a threshold for the amount of error between the pen reading on the chart and the reading from the test equipment that is allowed in the differential pressure element, static pressure element, and temperature element being installed or repaired. If any of the required test points are not within the values shown in Table 2–1, the element must be replaced. The threshold for the differential pressure element is 0.5 percent of the element range and 1.0 percent of the range for the static pressure element. These thresholds are based on the published accuracy specifications for a common brand of mechanical recorders used on Federal and Indian land (''Installation and Operation Manual, Models 202E and 208E'', ITT Barton Instruments, 1986, Table 1–1). The threshold for the temperature element assumes a typical temperature element range of 0–150 °F with an assumed accuracy of ±1.0 percent of range. This yields a tolerance of 1.5 °F which was rounded up to 2 °F for the sake of simplicity. The proposed requirement is less restrictive than the language of Order 5, which requires ''zero'' error for all three elements. Our experience over the last 3 decades indicates that a zero error is unattainable.

Proposed § 3175.92(a)(7) would establish standards for when the static-pressure pen is offset to account for atmospheric pressure. This would be a new requirement. The equation used to determine atmospheric pressure is discussed in Appendix 2 of this proposed rule. This rule proposes to add the requirement to offset the pen before obtaining the as-left values to ensure that the pen offset did not affect the calibration of any of the required test points.

Proposed § 3175.92(b) would establish requirements for how often a routine verification must be performed, with the minimum frequency, in months, shown in Table 2 in proposed § 3175.90. Under Order 5, a verification must be conducted every 3 months. This proposed rule would continue to require verification every 3 months for a low-volume FMP and would reduce the required frequency to every 6 months for a marginal-volume FMP. The required routine verification frequency for a chart recorder is twice as frequent as it is for an EGM system at low- and marginal-volume FMPs because chart recorders tend to drift more than the transducers of an EGM system.

Proposed § 3175.92(c) would establish procedures for performing a routine verification. These procedures would vary from the procedures used for verification after installation or repair, which are discussed in proposed § 3175.92(a).

Proposed § 3175.92(c)(1) would require that a successful leak test be performed before starting the verification. See the previous discussion of leak testing under proposed § 3175.92(a)(1). Section 3175.92(c)(2) would prohibit any adjustments to the recorder until the as-found verifications are obtained. Although this is not an explicit requirement in Order 5, it is general industry practice to obtain the as-found readings before making adjustments. However, some adjustments that have traditionally been allowed under Order 5 would be specifically prohibited under this proposed rule. For example, some meter calibrators will zero the static pressure pen to remove the atmospheric-pressure offset before obtaining any as-found values. Once the pen has been zeroed it is no longer possible to determine how far off the pen was reading prior to the adjustment, thus making it impossible to determine whether or not a volume correction would be required under 3175.92(f). This proposed section would make it clear that no adjustments, including the previous example, are allowed before obtaining the as-found values.

Proposed § 3175.92(c)(3) would require an as-found verification to be done at zero percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the differential and static element ranges. This would be a change from Order 5, which only requires a verification at zero and 100 percent of the element range and the normal operating position of the pens. The additional verification points were included to better identify pen error over the chart range. Mechanical recorders are generally more susceptible to varying degrees of recording error (sometimes referred to as an ''S'' curve) than EGM systems.

Proposed § 3175.92(c)(3)(i) would require that an as-found verification be done at a point that represents where the differential and static pens normally operate. This is the same requirement that is in Order 5. This section would require verification at the points where the pens normally operate only if there is enough information on-site to determine where these points are.

Proposed § 3175.92(c)(3)(ii) would establish additional requirements if there is not sufficient information on site to determine the normal operating points for the differential pressure and static pressure pens. The most likely example would be when the chart on the meter at the time of verification has just been installed and there were no historical pen traces from which to determine the normal operating values. In these cases, additional measurement points would be required at 5 percent and 10 percent of the element range to ensure that the flow-rate error can be accurately calculated once the normal operating points are known. The amount of flow-rate error is more sensitive to pen error at the lower end of the element range than at the upper end of the range. Therefore, more verification points would be required at the lower end to allow the calculation of flow-rate error throughout the range of the differential and static pressure elements. This would be a new requirement.

Proposed § 3175.92(c)(4) would establish standards for determining the as-found value of the temperature pen. In a flowing well, the use of a test-thermometer well is preferred because it more closely represents the flowing temperature of the gas compared to a water bath, which is often set at an arbitrary temperature. However, if the meter is not flowing, temperature differences within the pipeline may occur, which have the potential to introduce error between the primary-thermometer well and the test-thermometer well, thereby causing measurement bias. If the meter is not flowing, temperature verification must be done using a water bath. Order 5 has no requirements for determining the as-found values of flowing temperature and therefore this would be a new requirement.

Proposed § 3175.92(c)(5) would establish a threshold for the degree of allowable error between the pen reading on the chart and the reading from the test equipment for the differential, static, or temperature element being verified. If any of the required points to be tested, as defined in proposed § 3175.92(c)(3) or (4), are not within these thresholds, the element must be calibrated. For a discussion of the thresholds, see previous discussion of proposed § 3175.92(a)(6) and (7). The proposed requirement is less restrictive than the language of Order 5, which requires that the meter (differential pressure, static pressure, and temperature elements) be adjusted to ''zero'' error. In our experience over the last 3 decades, a zero error is unattainable.

Proposed § 3175.92(c)(6) would require that the differential- and static-pressure pens operate independently of each other, which is accomplished by adjusting the time lag between the pens. Please see previous discussion of proposed § 3175.92(a)(3) for further explanation of this proposed requirement.

Proposed § 3175.92(c)(7) would require a test of the differential-pen arc. This is the same as the requirement in Order 5.

Proposed § 3175.92(c)(8) would require an as-left verification if an adjustment to any of the meter elements was made. As-left readings are implied in Order 5 because the operator is required to adjust the meter to zero error. Obtaining as-left readings whenever a calibration is performed is also standard industry practice. The purpose of the as-left verification is to ensure that the calibration process, required in proposed § 3175.92(c)(5) through (7), was successful before returning the meter to service.

Proposed § 3175.92(c)(9) would establish a threshold for the amount of error allowed in the differential, static, or temperature element after calibration. If any of the required test points, as defined in proposed § 3175.92(c)(3) and (4), are not within the thresholds shown in Table 2–1, the element must be replaced and verified under proposed § 3175.92(c)(5) through (7). The proposed requirement is less restrictive than the language of Order 5, which requires that the meter (differential pressure, static pressure, and temperature elements) be adjusted to ''zero'' error. In our experience over the last 3 decades, a zero error is unattainable.

Proposed § 3175.92(c)(10) would establish standards if the static-pressure pen is offset to account for atmospheric pressure. Please see previous discussion of proposed § 3175.92(a)(7) for further explanation of this proposed requirement.

Marginal-volume FMPs would not be exempt from any of the verification or calibration requirements in proposed § 3175.92(c) because these requirements would not result in significant additional cost and are necessary to reduce potential measurement bias.

Proposed § 3175.92(d) would establish the minimum information required on a verification/calibration report. The purpose of this documentation is to: (1) Identify the FMP that was verified; (2) Ensure that the operator adheres to the proper verification frequency; (3) Ascertain that the verification/calibration was performed according to the requirements established in proposed § 3175.92(a) through (c), as applicable; (4) Determine the amount of error in the differential-pressure, static-pressure, and temperature pens; (5) Verify the proper offset of the static pen, if applicable; and (6) Allow the determination of flow rate error. The proposed rule would require documentation similar to Order 5, with the addition of the normal operating points for differential pressure, static pressure, flowing temperature, and the differential-device condition. The proposed rule would add the documentation requirement for the normal operating points to allow the BLM to confirm that the proper points were verified and to allow error calculation based on the applicable verification point. The proposed rule would require the primary-device documentation because the primary device is pulled and inspected at the same time as the operator performs a mechanical-recorder verification.

Proposed § 3175.92(e) would require the operator to notify the AO at least 72 hours before verification of the recording device. Order 5 requires only a 24-hour notice. The BLM proposes a longer notification period because a 24-hour notice is generally not enough time for the AO to be present at a verification. A 72-hour notice would be sufficient for the BLM to rearrange schedules, as necessary, to be present at the verification.

Proposed § 3175.92(f) would require the operator to correct flow-rate errors that are greater than 2 Mcf/day, if they are due to the chart recorder being out of calibration, by submitting amended reports to ONRR. Order 5 requires operators to submit amended reports if the error is greater than 2 percent regardless of how much flow the error represents. The 2 Mcf/day flow-rate threshold would eliminate the need for operators to submit—and the BLM to review—amended reports on low-volume meters, where a 2 percent error does not constitute a sufficient volume of gas to justify the cost of processing amended reports. The BLM derived the 2 Mcf/day threshold by multiplying the 2 percent threshold in Order 5 by 100 Mcf/day, which is the maximum flow-rate allowed to be measured with a chart recorder. Marginal-volume FMPs would be exempt from this requirement because the volumes are so small that even relatively large errors discovered during the verification process would not result in significant lost royalties or otherwise justify the costs involved in producing and reviewing amended reports. For example, if an operator discovered that an FMP measuring 15 Mcf/day was off by 10 percent (a very large error based on the BLM's experience) while performing a verification under this section, that would amount to a 1.5 Mcf/day error which, over a month's period, would be 45 Mcf. At $4 per Mcf, that error could result in an under- or over-payment in royalty of $22.50. It could take several hours for the operator to develop and submit amended OGOR reports and it could take several hours for both the BLM and ONRR to review and process those reports.

This proposed paragraph would also clarify a similar requirement in Order 5 by defining the points that are used to determine the flow-rate error. Calculated flow-rate error will vary depending on the verification points used in the calculation. The normal operating points must be used because these points, by definition, represent the flow rate normally measured by the meter.

Proposed § 3175.92(g) would require verification equipment to be certified at least every 2 years. The purpose of this requirement would be to ensure that the verification or calibration equipment meets its specified level of accuracy and does not introduce significant bias into the field meter during calibration. Two-year certification of verification equipment is typically recommended by the verification equipment manufacturer, and therefore, this does not represent a major change from existing procedures, although this would be a new requirement in this rule. The proposed paragraph would also require that proof of certification be available to the BLM and would set minimum standards as to what the documentation must include. Although this would also be a new requirement, it represents common industry practice.

§ 3175.93 Integration Statements

Proposed § 3175.93 would establish minimum standards for chart integration statements. The purpose of requiring the information listed is to allow the BLM to independently verify the volumes of gas reported on the integration statement. Currently, the range of information available on integration statements varies greatly. In addition, many integration statements lack one or more items of critical information necessary to verify the reported volumes. The BLM is not aware of any industry standards that apply to chart integration. This would be a new requirement.

§ 3175.94 Volume Determination

Proposed § 3175.94(a) would establish the methodology for determining volume from the integration of a chart. The methodology would include the adoption of the equations published in API MPMS 14.3.3 or AGA Report No. 3 (1985) for flange-tapped orifice plates. Under this proposal, operators using mechanical recorders would have the option to continue using the older AGA Report No. 3 (1985) flow equation. (Operators using EGM systems, on the other hand, would be required to use the flow equations in API 14.3.3 (2013) (see proposed § 3175.103).)

There are three primary reasons for allowing mechanical recorders to use a less strict standard. First, chart recorders, unlike EGM systems, would be restricted to FMPs measuring 100 Mcf/day or less. Therefore, any errors caused by using the older 1985 flow equation would not have nearly as significant of an effect on measured volume or royalty than they would for a high- or very-high-volume meter. Second, the BLM estimates that only 10 to 15 percent of FMPs still use mechanical recorders, and this number is declining steadily. This fact, combined with the proposed 100 Mcf/day flow rate restriction, means that only a small percentage of gas produced from Federal and Indian leases is measured using a mechanical recorder, significantly lowering the risk of volume or royalty error as a result of using the older 1985 equation. Third, it may be economically burdensome for a chart integration company to switch over to the new API 14.3.3 flow equations because much of the equipment and procedures used to integrate charts was established before the revision of AGA Report No. 3 (1985). The BLM is seeking data on the cost for chart integration companies to switch over to the new API MPMS 14.3.3 flow rate.

There are two variables in the API 14.3.3 flow equation that have changed since 1985. The current API equation includes a more accurate curve fit for determining the discharge coefficient (C_d) as a function of Reynolds number, Beta ratio, and line size. Further, the gas expansion factor was changed based on a more rigorous screening of valid data points. The current flow equation also requires an iterative calculation procedure instead of an equation that can be solved directly by hand, providing a more accurate flow rate. The difference in flow rate between the two equations, given the same input parameters, is less than 0.5 percent in most cases.

While API MPMS 14.3.3 provides equations for calculating instantaneous flow rate, it is silent on determining volume. Therefore, the methodology presented in API MPMS 21.1 for EGM systems would be adapted in this section for volume determination. This methodology is generally consistent with existing methods for chart integration and, as such, should not require any significant modifications. For primary devices other than flange-tapped orifice plates, the BLM would approve, based on the PMT's recommendation, the equations that would be used for volume determination.

Proposed § 3175.94(a)(3) defines the source of the data that goes into the flow equation.

Proposed § 3175.94(b) would establish a standard method for determining atmospheric pressure used to convert pressure measured in psig to units of psia, which is used in the calculation of flow rate. Any error in the value of atmospheric pressure will cause errors in the calculation of flow rate, especially in meters that operate at low pressure. Order 5 requires the use of the atmospheric pressure defined in the buy/sell contract, if specified. If it is not specified, Order 5 requires atmospheric pressure to be determined through a measurement or a calculation based on elevation. The BLM is proposing to eliminate the use of a contract value for atmospheric pressure because contract provisions are not always in the public interest and do not always dictate the best measurement practice. A contract value that is not representative of the actual atmospheric pressure at the meter will cause measurement bias, especially in meters where the static pressure is low.

This rule also proposes to eliminate the option of operators measuring actual atmospheric pressure at the meter location for mechanical recorders. Instead, atmospheric pressure would be determined from an equation or Table (see Appendix 2) based on elevation. Atmospheric pressure is used in one of two ways for a mechanical recorder. First, the static-pressure reading from the chart in psig is converted to absolute pressure during the integration process by adding atmospheric pressure to the static pressure reading. Or, second, the static pressure pen can be offset from zero in an amount that represents atmospheric pressure. In the second case, the static-pressure line on the chart already has atmospheric pressure added to it and no further corrections are made during the integration of the charts. The static-pressure element in a chart recorder is a gauge pressure device—in other words, it measures the difference between the pressure from the pressure tap and atmospheric pressure. Offsetting the pen does not convert it into an absolute pressure device; it is only a convenient way to convert gauge pressure to atmospheric pressure. If measured atmospheric pressure were allowed, the measurement could be made when, for example, a low-pressure weather system was over the area. The measured atmospheric pressure in this example would not be representative of the average atmospheric pressure and would bias the measurements to the low side. This is much more critical in meters operating at low pressure than in meters operating at high pressure. The BLM believes that operators rarely use measured atmospheric pressure to offset the static pressure; therefore, this change would have no significant impact on current industry practice. The treatment of atmospheric pressure for mechanical recorders would be different than it would be for EGM systems because many EGM systems measure absolute pressure, whereas all mechanical recorders are gauge-pressure devices (please see the discussion of proposed § 3175.102(a)(3) for further analysis).

The equation to determine atmospheric pressure from elevation (''U.S. Standard Atmosphere'', National Aeronautics and Space Administration, 1976 (NASA–TM–X–74335)), prescribed in Appendix 2 to the proposed rule, produces similar results to the equation normally used for atmospheric pressure for elevations less than 7,000 feet mean sea level (see Figure 3).

§ 3175.100 Electronic Gas Measurement (Secondary and Tertiary Device)

Proposed § 3175.100 would set standards for the installation, operation, and inspection of EGM systems used for FMPs. The proposed standards include requirements prescribed in the proposed rule as well as requirements in referenced API documents. Table 3 was developed as part of proposed § 3175.100 to clarify and provide easy reference to what requirements apply to different aspects of EGM systems and to adopt specific API standards as necessary. The first column of Table 3 lists the subject area for which a standard is proposed. The second column of Table 3 contains a reference for the standard that would apply to the subject area described in the first column (by section number and paragraph, mostly in proposed §§ 3175.101 through 3175.104). The final four columns of Table 3 indicate the FMP categories to which the standard would apply. As is the case in other tables, the FMPs are categorized by the amount of flow they measure on a monthly basis as follows: ''M'' is marginal-volume FMP, ''L'' is low-volume FMP, ''H'' is high-volume FMP, and ''V'' is very-high-volume FMP. Definitions for the various classifications are given in proposed § 3175.10. An ''x'' in a column indicates that the standard listed applies to that category of FMP. A number in a column indicates a numeric value for that category, such as the maximum number of months between inspections. For example, the maximum time between verifications, in months, is shown in Table 3 under ''Routine verification frequency.'' Any character in a column other than an ''x'' is explained in the body of the proposed standard.

Proposed § 3175.100 would adopt API MPMS 21.1.7.3, regarding EGM equipment commissioning; API MPMS 21.1.9, regarding access and data security; and API MPMS 21.4.4.5, regarding the no-flow cutoff. The BLM has reviewed these sections and believes they are appropriate for use at FMPs. The existing statewide NTLs referenced similar sections in the previous version of API MPMS 21.1 (1993); therefore, this is not a significant change from existing requirements.

§ 3175.101 Installation and Operation of Electronic Gas Measurement Systems

Proposed § 3175.101(a) would set requirements for manifolds and gauge lines, which are not addressed in Order 5. Gauge lines connect the pressure taps on the primary device to the EGM secondary device and can contribute to bias and uncertainty if not properly designed and installed. (The requirements in this proposed section are similar to the requirements for installation and operation of gauge lines used in mechanical recorders.)

It is standard industry practice to install gauge lines with a minimum inside diameter of 0.375″, as is proposed in § 3175.101(a)(1). The intent of this standard is to reduce frictional effects potentially caused by smaller line sizes.

Proposed § 3175.101(a)(2) would be a new requirement that gauge lines be made only of stainless steel. Carbon steel, copper, plastic tubing, or other material could corrode and leak, presenting a safety issue as well as biased measurement.

Proposed § 3175.101(a)(3) would require gauge lines to be sloped up and away from the meter tube to allow any condensed liquids to drain back into the meter tube. A build-up of liquids in the gauge lines could significantly bias the differential pressure reading. While both of these requirements are new, they do not represent a significant change from standard industry practice.

The requirements in proposed § 3175.101(a)(1), (4), (5), (6) and (7) are intended to reduce a phenomenon known as ''gauge line error,'' caused when changes in differential or static pressure due to pulsating flow are amplified by the gauge lines, thereby causing increased bias and uncertainty. API MPMS 14.3.2.5.4.3 recommends that gauge lines be the same diameter along their entire length, which would be adopted as a minimum standard in proposed § 3175.101(a)(4).

Proposed §§ 3175.101(a)(5) and (6) are intended to minimize the volume of gas contained in the gauge lines because excessive volume can contribute significantly to gauge-line error whenever pulsation exists. These paragraphs would prohibit anything except the static-pressure connection in a gauge line, and are intended to prohibit the practice of connecting multiple secondary devices to a single set of pressure taps, the use of drip pots, and the use of gauge lines as a source for pressure-regulated control valves and other equipment. A second set of transducers would be allowed if the operator chooses to employ redundancy verification. Proposed § 3175.101(a)(7) would limit the gauge lines to 6 feet in length, again to minimize the amount of gas volume contained in the gauge lines. Both of these requirements would be new.

Marginal-volume FMPs would be exempt from the requirements of proposed § 3175.101(a) because the potential effect on royalty would be minimal and our experience suggests that the costs would outweigh potential royalty benefits.

Proposed § 3175.101(b) and (c) would specify the minimum information that the operator would have to maintain on site for an EGM system and make available to the BLM for inspection. The purpose of the data requirements in these sections is to allow BLM inspectors to: (1) Verify the flow-rate calculations being made by the flow computer; (2) Compare the daily volumes shown on the flow computer to the volumes reported to ONRR; (3) Determine the uncertainty of the meter; (4) Determine if the Beta ratio is within the required range; (5) Determine if the upstream and downstream piping meets minimum standards; (6) Determine if the thermometer well is properly placed; (7) Determine if the flow computer and transducers have been type-tested under the protocols described in proposed §§ 3175.130 and 3175.140; (8) Verify that the primary device has been inspected at the required frequency; and (9) Verify that the transducers have been verified at the required frequency.

Proposed § 3175.101(b) would require that each EGM system include a display and would set minimum requirements for the information to be displayed. The proposed requirements are similar to existing requirements in paragraph 4 of the statewide NTLs for EFCs with the following additions and modifications:

(1) Proposed § 3175.101(b)(3) would require the units of measure to be on the display; in contrast, the statewide NTLs only require the units of measure to be on site. We propose this change because of the potential to misidentify the units of measure on the data card that would otherwise be required.

(2) Instead of a meter identification number as currently required, § 3175.101(b)(4)(i) would require the

new FMP number to be displayed so that the BLM can identify the meter.

(3) The software version requirement proposed in § 3175.101(b)(4)(ii) is in addition to existing requirements and would be used to ensure that the software version in use has gone through the testing protocol proposed in §§ 3175.130 and 3175.140.

(4) The previous day flow time proposed in § 3175.101(b)(4)(viii) would be a new requirement to allow the calculation of average daily flow rate.

(5) The previous day average differential pressure, static pressure, and flowing temperature proposed in § 3175.101(b)(4)(ix), (x), and (xi), respectively, would be new requirements which would provide the BLM with average values to use in the determination of uncertainty and would define the ''normal'' operating point for verification purposes. The BLM proposes these requirements because instantaneous values are often not representative of typical operating conditions, especially in meters that experience highly variable flow rates such as those associated with plunger lift operations.

(6) The proposed requirement for displaying relative density in § 3175.101(b)(4)(xii) would be a new requirement because relative density is typically updated every time a new gas analysis is obtained and the updates are often done remotely, making it difficult to update a data card in a timely manner.

(7) The primary device information proposed in § 3175.101(b)(4)(xiii) would be required because the size can change every time an orifice plate or other type of primary device is changed and the calculation of flow rate is based on these values.

(8) Proposed § 3175.101(b)(5) would require that the instantaneous values be displayed consecutively to allow a more accurate verification of the instantaneous flow rate. The more time that passes between the display of instantaneous data, the more the flow rate can change over that time and the less accurate the verification is.

Proposed § 3175.101(c) would set requirements for information that must be on site, but not necessarily on the EGM system display. These requirements are similar to the requirements of the statewide NTLs for EFCs, with the following additions and modifications:

(1) The elevation of the FMP that would be required under proposed § 3175.101(c)(1) would allow the BLM to verify the value of atmospheric pressure used to derive the absolute static pressure.

(2) Proposed § 3175.101(c)(3) would require the make, model, and location of flow conditioners to be identified to ensure that all flow conditioners have been approved by the BLM and installed according to BLM requirements.

(3) Proposed § 3175.101(c)(4) would require that the location of 19-tube-bundle flow straighteners (if used) be indicated in the on-site records so that BLM inspectors can verify that they have been installed to API specifications.

(4) The flow computer make and model number that would be required under proposed § 3175.101(c)(5) and (c)(6) would allow the BLM to verify that the flow computer has been tested under the protocol described in proposed § 3175.140 and has been approved by the BLM as required in proposed § 3175.44.

(5) Proposed § 3175.101(c)(9) and (c)(10) would add requirements to maintain on site the dates of the last primary-device inspection and secondary-device verification. This would allow the BLM to determine whether the meter is being inspected and verified as required under proposed §§ 3175.80(c), 3175.80(d), 3175.92(b) and 3175.102(b). Proposed requirements in § 3175.101(c)(2), (3), (7) and (8) are the same as the existing requirements in the statewide NTLs for EFCs.

Proposed § 3175.101(d) would require the differential pressure, static pressure, and temperature transducers to be operated within the lower and upper calibrated limits of the transducer. Inputs that are outside of these limits would be subject to higher uncertainty and if the transducer is over-ranged, the readings may not be recorded The term ''over-ranged'' means that the pressure or temperature transducer is trying to measure a pressure or temperature that is beyond the pressure or temperature it was designed or calibrated to measure. In some transducers—typically older ones—the transducer output will be the maximum value for which it was calibrated, even when the pressure being measured exceeds that value. For example, if a differential pressure transducer that has a calibrated range of 250 inches of water is measuring a differential pressure of 300 inches of water, the transducer output will be only 250 inches of water. This results in loss of measured volume and royalty. Many newer transducers will continue to measure values that are over their calibrated range; however, because the transducer has not been calibrated for these values, the uncertainty may be higher than the transducer specification indicates.

Proposed § 3175.101(e) would require the flowing-gas temperature to be continuously recorded. Flowing temperature is needed to determine flowing gas density, which is critical to determining flow rate and volume. Order 5 requires continuous temperature measurement for meters measuring more than 200 Mcf/day, while the proposed rule would require continuous temperature measurement on all FMPs except marginal-volume FMPs. Marginal-volume FMPs would be exempt from this requirement because the potential effect on royalty would be minimal and our experience suggests that the costs would outweigh potential royalty. For marginal-volume FMPs, any errors introduced by using an estimated temperature in lieu of a measured temperature would not have a significant impact on royalties.

§ 3175.102 Verification and Calibration of Electronic Gas Measurement Systems

Proposed § 3175.102(a) would include several specific requirements for the verification and calibration of transducers following installation and repair. Order 5 also requires a verification upon installation or after repairs. This would be a minor change to Order 5 to differentiate the procedures that are specific to this type of verification from the procedures required for a routine verification under proposed § 3175.102(c). The primary difference between proposed §§ 3175.102(a) and (c) is that an as-found verification would not be required if the meter is being verified following installation or repair.

Proposed § 3175.102(a)(1) would require a leak test before performing a verification or calibration. (Please see the previous discussion regarding proposed § 3175.92(a)(1) for further explanation of leak testing.)

Proposed § 3175.102(a)(2) would require a verification to be done at the points required by API MPMS 21.1.7.3.3 (zero percent, 25 percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the calibrated span of the differential-pressure and static-pressure transducers, respectively). This would be an addition to the requirements of Order 5 and the statewide NTLs for EFCs, and would include more verification points than are required for a routine verification described in proposed § 3175.102(c). The purpose of requiring more verification points in this section would be: (1) For new installations, the normal operating points for differential and static pressure may not be known because of a lack of historical operating information; and (2) A more rigorous verification is required to ensure that new or repaired equipment is working properly by verifying more points between the lower and upper calibrated limits of the transducer.

Proposed § 3175.102(a)(3) would also require the operator to calculate the value of atmospheric pressure used to calibrate an absolute-pressure transducer from elevation using the equation or table given in Appendix 2 of the proposed rule, or be based on a measurement made at the time of verification for absolute-pressure transducers in an EGM system. This would be a change from requirements in Order 5 because under this proposal, the value for atmospheric pressure defined in the buy/sell contract would no longer be allowed unless it met the requirements stated in this section. The BLM is proposing to eliminate the use of a contract value for atmospheric pressure because contract provisions are not always in the public interest, and they do not always dictate the best measurement practice. A contract value that is not representative of the actual atmospheric pressure at the meter will cause measurement bias, especially in meters where the static pressure is low. If a barometer is used to determine the atmospheric pressure, the barometer must be certified by the National Institute of Standards and Technology (NIST) and have an accuracy of ±0.05 psi, or better. This will ensure the value of atmospheric pressure entered into the flow computer during the verification process represents the true atmospheric pressure at the meter station.

This proposed requirement is different from the requirements in proposed § 3175.94(b) for the treatment of atmospheric pressure in connection with mechanical recorders. The difference results from the design of the pressure measurement device—whether it is a gauge pressure device or an absolute pressure device. A gauge pressure device measures the difference between the applied pressure and the atmospheric pressure. An absolute pressure device measures the difference between the applied pressure and an absolute vacuum.

The use of a barometer to determine atmospheric pressure would be allowed only when calibrating an absolute pressure transducer. It would not be allowed for gauge pressure transducers. Because all mechanical recorders are gauge pressure devices (even if the pen has been offset to account for atmospheric pressure), the use of a barometer to establish atmospheric pressure would not be allowed.

Proposed § 3175.102(a)(4) would require the operator to re-zero the differential pressure transducer under working pressure before putting the meter into service. Differential pressure transducers are verified and calibrated by applying known pressures to the high side of the transducer while leaving the low side vented to the atmosphere. When a differential pressure transducer is placed into service, the transducer is subject to static (line) pressure on both the high side and the low side (with small differences in pressure between the high and low sides due to flow). The change from atmospheric pressure conditions to static pressure conditions can cause all the readings from the transducer to shift, usually by the same amount.

Typically, the higher the static pressure is, the more shift occurs. Zero shift can be minimized by re-zeroing the differential pressure transducer when the high side and low side are equalized under static pressure. The re-zeroing proposed in this section would be a new requirement that would eliminate measurement errors caused by static pressure zero-shift of the differential pressure transducer. Re-zeroing is recommended in API MPMS 21.1.8.2.2.3, but not required. The BLM proposes to require it here.

Proposed § 3175.102(b) would establish requirements for how often a routine verification must be done where the minimum frequency, in months, is shown in Table 3 in proposed § 3175.100. Under Order 5, a verification must be conducted every 3 months. The proposed rule would require a verification every month for very-high-volume FMPs, every 3 months for high-volume FMPs, every 6 months for low-volume FMPs, and every 12 months for marginal-volume FMPs. Because there is a greater risk of measurement error for volume calculation for a given transducer error at higher-volume FMPs, the proposed rule would increase the verification frequency as the measured volume increases.

Proposed § 3175.102(c) would adopt the procedures in API MPMS 21.1.8.2 for the routine verification and calibration of transducers with a number of additions and clarifications. Order 5 also requires a routine verification. The primary difference between § 3175.102(a) and (c) is that an as-found verification is required for routine verifications.

Proposed § 3175.102(c)(1) would require a leak test before performing a verification. A leak test is not specified in API MPMS 21.1.8.2; however, the BLM believes that performing a leak test is critical to obtaining accurate measurement. Please see previous discussion of proposed § 3175.92(a)(1) for further explanation of leak testing.

Proposed § 3175.102(c)(2) and (3) would require that the operator perform a verification at the normal operating point of each transducer. This clarifies the requirements in API MPMS 21.1.8.2.2.3, which requires a verification at either the normal point or 50 percent of the upper user-defined operating limit. This section would also define how the normal operating point is determined because this is a common point of confusion for operators and the BLM.

Proposed § 3175.102(c)(4) would require the operator to correct the as-found values for differential pressure taken under atmospheric conditions to working pressure values based on the difference between working pressure zero and the zero value obtained at atmospheric pressure (see previous discussion of proposed § 3175.102(a)(4) for further explanation of zero shift). API MPMS 21.1.8.2.2.3 recommends that this correction be made, but does not require it. API also provides a methodology for the correction. The correction methodology in API MPMS 21.1, Annex H would be required in this section.

Proposed § 3175.102(c)(5) would adopt the allowable tolerance between the test device and the device being tested as stated in API MPMS 21.1.8.2.2.2. This tolerance is based on the reference uncertainty of the transducer and the uncertainty of the test equipment.

Proposed § 3175.102(c)(6) would clarify that all required verification points must be within the verification tolerance before returning the meter to service. This requirement is implied by API MPMS 21.1.8.2.2.2, but is not clearly stated.

Proposed § 3175.102(c)(7) would require the differential pressure transducer to be zeroed at working pressure before returning the meter to service. This is implied by API MPMS 21.1.8.2.2.3, but not required. Refer to the discussion of zero shift under 3175.102(a)(4) for further information.

Proposed § 3175.102(d) would allow for redundancy verification in lieu of a routine verification under § 3175.102(c). Redundancy verification was added to the current version of API MPMS 21.1 as an acceptable method of ensuring the accuracy of the transducers in lieu of performing routine verifications. Redundancy verification is accomplished by installing two EGM systems on a single differential flow meter and then comparing the differential pressure, static pressure, and temperature readings from the two

EGM systems. If the readings vary by more than a set amount, both sets of transducers would have to be calibrated and verified. Operators would have the option of performing routine verifications at the frequency required under proposed § 3175.102(b) or employing redundancy verification under this paragraph. Operators may realize cost savings by adopting redundancy verification, especially on high- or very-high-volume FMPs. The proposed rule would adopt API MPMS 21.1.8.2 procedures for redundancy verifications with several additions and clarifications as follows.

Proposed § 3175.102(d)(1) would require the operator to identify separately the primary set of transducers from the set of transducers that is used as a check. This requirement would allow the BLM to know which set should be used for auditing the volumes reported on the Oil and Gas Operations Report (OGOR).

Proposed § 3175.102(d)(2) would require the operator to compare the average differential pressure, static pressure, and temperature readings taken by each transducer set every calendar month. API MPMS 21.1.8.2 does not specify a frequency at which this comparison should be done.

Proposed § 3175.102(d)(3) would establish the tolerance between the two sets of transducers that would trigger a verification of both sets of transducers under proposed § 3175.102(c). API MPMS 21.1 does not establish a set tolerance. This proposed section would also require the operator to perform a verification within 5 days of discovering the tolerance had been exceeded.

Proposed § 3175.102(e) would establish requirements for documenting a verification and calibration. The new documentation requirements would be similar to the requirements in Order 5, with the following additions and modifications:

- The FMP number, once assigned, would be a new requirement and would take the place of the station or meter number previously required;
- The lease, communitization agreement, unit, or participating area number would no longer be required once the FMP number is assigned, because the FMP number would provide this information;
- The temperature and pressure base would no longer be required in this proposed rule since these values are set in regulation (43 CFR 3162.7–3);
- Recording the time and date of the previous verification would be a new requirement and was added to allow the BLM to enforce the required verification frequencies;
- Recording the normal operating point for differential pressure, static pressure, and flowing temperature would be a new requirement to allow the BLM to ensure that the required verification points were tested and to facilitate the determination of meter verification error.
- Recording the condition of the differential device would be a new requirement because documentation of differential device condition is needed to ensure accurate measurement. Since inspection of the primary device would be required at the same time a verification is performed, this was added to the verification report; and
- Recording information regarding the verification equipment would be a new requirement to allow the BLM to determine that the proper verification tolerances were used.

This section would also establish the information that the operator must retain on site for redundancy verifications.

Proposed § 3175.102(f) would require the operator to notify the BLM at least 72 hours before verification of an EGM system. Order 5 requires only 24-hour notice. A longer notification period is proposed because 24-hour notice is generally not enough time for the BLM to be present at a verification. A 72-hour notice would be sufficient for the BLM to rearrange schedules, as necessary, to be present at the verification.

Proposed § 3175.102(g) would require correction of flow-rate errors greater than 2 percent or 2 Mcf/day, whichever is less, if they are due to the transducers being out of calibration, by submitting amended reports to ONRR. This is a change from Order 5, which required amended reports only if the flow-rate error was greater than 2 percent. For lower volume meters, a 2 percent error may represent only a small amount of volume. Assuming the 2 percent error resulted in an underpayment of royalty, the amount of royalty recovered by receiving amended reports may not cover the costs incurred by the BLM or ONRR of identifying and correcting the error. This rule proposes to add an additional threshold of 2 Mcf/day to exempt amended reports on low-volume FMPs.

Proposed paragraph (9) would also clarify a similar requirement in Order 5 to submit corrected reports if the flow-rate-error threshold is exceeded by defining the points that are used to determine the flow rate error. Calculated flow-rate error will vary depending on the verification points used in the calculation. The normal operating points must be used because these points, by definition, represent the flow rate normally measured by the meter. As specified in Table 3 (proposed § 3175.100), marginal-volume FMPs would be exempt from this requirement because the volumes are so small that even relatively large errors discovered during the verification process will not result in significant lost royalties, and thus, the process of amending reports would not be worth the costs involved for either the operator or the BLM (please see the example given in the discussion of 3175.92(f)).

Proposed § 3175.102(h)(1) would require verification equipment to be certified at least every 2 years. The purpose of this requirement would be to ensure that the verification or calibration equipment meets its specified level of accuracy and does not introduce significant bias into the field meter during calibration. Two-year certification of verification equipment is not required by API MPMS 21.1; however, the BLM believes that periodic certification is necessary. The proposal would not represent a change from existing requirements. This proposed requirement is consistent with requirements in the previous edition of API MPMS 21.1 (1993), which is adopted by the statewide NTLS for EFCs. The proposed section would also require that proof of certification be available to the BLM and would set minimum standards as to what the documentation must include. Although the minimum documentation standards would be a new requirement, they represent common industry practice.

Proposed paragraph (b) would modify the test equipment requirements in the statewide NTLs by adopting language in API MPMS 21.1.8.4. The statewide NTLs, which adopted the standards of API MPMS 21.1 (1993), required that the test equipment be at least 2 times more accurate than the device being tested. The purpose of this requirement was to reduce the additional uncertainty from the test equipment to an insignificant level. Many of the newer transducers being used in the field are of such high accuracy that field test equipment cannot meet the standard of being twice as accurate. Therefore, the current API MPMS 21.1 allows test equipment with an uncertainty of no more than 0.10 percent of the upper calibrated limit of the transducer being tested, even if it was not two times more accurate than the transducer being tested. For example, verifying a transducer with a reference accuracy of 0.10 percent of upper calibrated limit with test equipment that was at least twice as accurate as the device being tested, would require the test equipment to have an accuracy of 0.05 percent or better of the upper calibrated limit of the device being tested.

This level of accuracy is very difficult to achieve outside of a laboratory. As a result, API MPMS 21.1.8.4, and proposed § 3175.102(h), would only require the test equipment to have an accuracy of 0.10 percent of the upper calibrated limit of the device being tested. However, because the test equipment is no longer at least twice as accurate as the device being tested (they would both have an accuracy of 0.10 percent in this example), the additional uncertainty from the test equipment is no longer insignificant and would have to be accounted for when determining overall measurement uncertainty. The BLM would verify the overall measurement uncertainty—including the effects of the calibration equipment uncertainty—by using the BLM Uncertainty Calculator or an equivalent tool during the witnessing of a meter verification.

§ 3175.103 Flow Rate, Volume, and Average Value Calculation

Proposed § 3175.103(a) would prescribe the equations that must be used to calculate the flow rate. Proposed § 3175.103(a)(1) would apply to flange-tapped orifice plates and would represent a change from the statewide EFC NTLs because the NTLs allow the use of either the API MPMS 14.3.3 or the AGA Report No.3 (1985) flow equation. The proposed rule would not allow the use of the AGA Report No. 3 (1985) flow equation because it is not as accurate as the API MPMS 14.3.3 flow equation and can result in measurement bias. The NTLs also allow the use of either AGA Report 8 (API MPMS 14.2) [4] or NX–19 [5] to calculate supercompressibility. The proposed rule would only allow API MPMS 14.2 because it is a more accurate calculation.

Proposed § 3175.103(a)(2) would require use of BLM-approved equations for devices other than a flange-tapped orifice plate. Because there are typically no API standards for these devices, the PMT would have to check the equations derived by the manufacturer to ensure they were consistent with the laboratory testing of these devices. For example, a manufacturer may use one equation to establish the discharge coefficient for a new type of meter that is being tested in the laboratory, while using another equation for the meter it supplies to operators in the field, potentially resulting in measurement bias or increased uncertainty. The BLM would require that only the equation used during testing be used in the field. This would be a new requirement.

Proposed § 3175.103(b) would establish a standard method for determining atmospheric pressure that is used to convert psig to psia. This would be a new requirement because Order 5 requires the use of the atmospheric pressure defined in the buy/sell contract, if specified. If it is not specified, Order 5 requires atmospheric pressure to be determined through a measurement or a calculation based on elevation. (See the previous discussion of proposed § 3175.94(b) for an explanation of the rationale for this change.)

Proposed § 3175.103(c) would require that volumes and other variables used for verification be determined under API MPMS 21.1.4 and Annex B of API MPMS 21.1. This would be a change to existing requirements because the existing statewide EFC NTLs adopt the previous version of API MPMS 21.1.

§ 3175.104 Logs and Records

Proposed § 3175.104(a) would establish minimum standards for the data that must be provided in a daily and hourly quantity transaction record. The data requirements are listed in API MPMS 21.1.5.2, with the following additions and modifications:

- The FMP number, once established, would be required on all reports (API MPMS 21.1 does not require this data);
- The number of required significant digits is specified. API MPMS 21.1.5.2 recommends that the data be stored with enough resolution to allow recalculation within 50 parts per million, but it does not specify the number of significant digits required in the quantity transaction record (QTR). The BLM added this requirement because if too few significant digits are reported it is impossible for the BLM to recalculate the reported volume with sufficient accuracy to determine if it is correct or in error. The BLM believes that five significant digits is sufficient to recalculate the reported volumes to the necessary level of accuracy; and
- An indication of whether the QTR shows the integral value or average extension under API MPMS 21.1. (Integral value generally is the summation of the product of the square root of the differential pressure and the square root of the static pressure taken at one-second intervals over an hour or a day. Average extension is the integral value divided by the flowing time.) API MPMS 21.1 allows either the integral value or average extension to be reported; however, the recalculation of reported volume is performed differently depending on which value is given. For the BLM to use the appropriate equation to recalculate volumes, the BLM must know what value is listed.

This proposed paragraph would require that both daily and hourly QTRs submitted to the BLM must be original, unaltered, unprocessed, and unedited. It is common practice for operators to submit BLM-required QTRs using third-party software that compiles data from the flow computers and uses it to generate a standard report. However, the BLM has found in numerous cases that the data submitted from the third-party software is not the same as the data generated directly by the flow computer. In addition, the BLM consistently has problems verifying the volumes reported through reports generated by third-party software. Under this proposed paragraph, data submitted to the BLM that was generated by third-party software would not meet the requirements of this section and the BLM would not accept it.

Proposed § 3175.104(b) would be a new requirement that would establish minimum standards for the data that must be provided in the configuration log. The unedited data are similar to the existing requirements found in API MPMS 21.1, which was adopted by the statewide NTLs for EFCs, with the following additions and modifications:

- The FMP number, once established, would be required on all reports;
- The software/firmware identifiers that would allow the BLM to determine if the software or firmware version was approved by the BLM;
- For marginal-volume FMPs, the fixed temperature, if the temperature is not continuously measured, that would allow the BLM to recalculate volumes; and
- The static-pressure tap location that would allow the BLM to recalculate volumes and verify the flow rate calculations done by the flow computer.

As described under proposed § 3175.104(a), configuration logs generated by third-party software would not be accepted. This proposed paragraph would also require that the configuration log contain a snapshot report that would allow the BLM to verify the flow-rate calculation of the flow computer.

Proposed § 3175.104(c) would establish minimum standards for the data that must be provided in the event

[4] AGA Report 8, ‘‘Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases’’, is the same as API MPMS 14.2.

[5] NX–19 was published in 1961 by the AGA Pipeline Research Committee and was officially titled the ‘‘PAR Research Project NX–19’’; it was the predecessor to API MPMS 14.2 for the calculation of compressibility factors.

log. This proposed section would require that the event log retain all logged changes for the time period specified in proposed § 3170.7, published previously. See 80 FR 40,768 (July 13, 2015) This provision would be added to ensure that a complete meter history is maintained to allow verification of volumes. Proposed § 3175.104(c)(1) would be a new requirement to record power outages in the event log. This is not currently required by API MPMS 21.1 or the statewide NTLs for EFCs. The BLM is proposing this requirement to ensure that the BLM can determine when the meter was not receiving data to calculate flow rate or volume.

Proposed § 3175.109(d) would require the operator to retain an alarm log as required in API MPMS 21.1.5.6. The alarm log records events that could potentially affect measurement, such as over-ranging the transducers, low power, or the failure of a transducer.

§ 3175.110 Gas Sampling and Analysis

All of the provisions in proposed § 3175.110 would be new, since the only requirement in Order 5 relating to gas sampling is for an annual determination of heating value. This proposed section would set standards for gas sampling and analysis at FMPs. Although there are industry standards for gas sampling and analysis, none of these standards were proposed for adoption in whole because the BLM believes that they would be difficult to enforce as written. However, some specific requirements within these standards are sufficiently enforceable and would be adopted in this section. Heating value, which is determined from a gas sample, is as important to royalty determination as volume. Relative density, which is determined from the same gas sample, affects the calculation of volume. To ensure the gas heating value and relative density are properly determined and reported, the BLM is proposing the requirements described in this section. These requirements would address where a sample must be taken, how it must be taken, how the sample is analyzed, and how heating value is reported.

Table 4 in this proposed section contains a summary of requirements for gas sampling and analysis. The first column of Table 4 lists the subject of the proposed standard. The second column contains a reference for the standard (by section number and paragraph) that would apply to each subject area. The final four columns indicate the categories of FMPs for which the standard would apply. The FMPs are categorized by the amount of flow they measure on a monthly basis. As in other tables, ''M'' is marginal-volume FMP, ''L'' is low-volume FMP, ''H'' is high-volume FMP, and ''V'' is very-high-volume FMP. Definitions of the various classifications are included in proposed § 3175.10. An ''x'' in a column indicates that the standard listed applies to that category of FMP.

§ 3175.111 General Sampling Requirements

Proposed § 3175.111(a) would establish the allowable methods of sampling. These sampling methods have been reviewed by the BLM and have been determined to be acceptable for heating value and relative density determination at FMPs.

Proposed § 3175.111(b) would set standards for heating requirements which are based on several industry references requiring the heating of all sampling components to at least 30 °F above the hydrocarbon dew point. The purpose of the heating requirement is to prevent the condensation of heavier components, which could bias the heating value. This proposed section would apply to all sampling systems, including spot sampling using a cylinder, spot sampling using a portable gas chromatograph, composite sampling, and on-line gas chromatographs. Because most of the onshore FMPs will be downstream of a separator, the ''hydrocarbon dew point'' would be defined as the flowing temperature of the gas at the time of sampling, unless otherwise approved by the AO (see the proposed definition of ''hydrocarbon dew point''). This would require the heating of all components of the gas sampling system at locations where the ambient temperature is less than 30 °F above the flowing temperature at the time of sampling.

§ 3175.112 Sampling Probe and Tubing

Proposed § 3175.112 would set standards for the location of the sample probe. The intent of the standard would be to obtain a representative sample of the gas flowing through the meter. Samples taken from the wall of a pipe or a meter manifold would not be representative of the gas flowing through the meter and could bias the heating value used in royalty determination.

Proposed § 3175.112(b)(1) places limits on how far away the sample probe can be from the primary device to ensure that the sample taken accurately represents the gas flowing through the meter. API 14.1 requires the sample probe to be at least five pipe diameters downstream of a major disturbance such as a primary device, but it does not specify a maximum distance. Under this proposal the operator would have to place the sample probe between 1.0 and 2.0 times dimension ''DL'' (downstream length) downstream of the primary device. Dimension ''DL'' (API 14.3.2, Tables 2.7 and 2.8) ranges from 2.8 to 4.5, depending on the Beta ratio. Therefore, the sample probe would have to be placed between 2.8 and 9.0 pipe diameters downstream of the orifice plate, which is different than the requirement in API 14.1 noted above.

The sampling methods listed in API 14.1 and GPA 2166–05 will provide representative samples only if the gas is at or above the hydrocarbon dew point. It is likely that the gas at many FMPs is at or below the hydrocarbon dew point because many FMPs are immediately downstream of a separator. A separator necessarily operates at the hydrocarbon dew point, and any temperature reduction between the separator and the meter will cause liquids to form at the meter. To properly account for the total energy content of the hydrocarbons flowing through the meter, the sample must account for any liquids that are present. Gas immediately downstream of a primary device has a higher velocity, lower pressure, and a higher amount of turbulence than gas further away from the primary device. As a result, the BLM believes that liquids present immediately downstream of the primary device are more likely to be disbursed into the gas stream than attached to the pipe walls. Therefore, a sample probe placed as close to the primary device as possible should capture a more representative sample of the hydrocarbons—both liquid and gas—flowing through the meter than a sample probe placed further downstream of the meter. Any liquids captured by the sample probe would be vaporized because of the heating requirements in § 3175.111(b).

The BLM is requesting data supporting or contradicting any correlation between sample probe location and heating value or composition. The BLM is also requesting alternatives to this proposal, such as wet gas sampling techniques.

Locating the sample probe in the same ambient conditions as the primary device, as proposed in § 3175.112(b)(2), is not specifically addressed in API or GPA standards, but is intended to ensure that the gas sample contains the same constituents as the gas that flowed through the primary device. For example, if a primary device is located inside a heated meter house and the sample probe is outside the meter house, then condensation of heavier gas components could occur between the primary device and the sample point, thereby biasing the heating value and relative density of the gas.

Proposed § 3175.112(c)(1) through (3) would set standards for the design of the sample probe, which are based on API MPMS 14.1 and GPA 2166. The sample probe ensures that the gas sample is representative of the gas flowing through the meter. The sample probe extracts the gas from the center of the flowing stream, where the velocity is the highest. Samples taken from or near the walls of the pipe tend to contain more liquids and are less representative of the gas flowing through the meter.

Proposed § 3175.112(c)(4) would prohibit the use of membranes or other devices used in sample probes to filter out liquids that may be flowing through the FMP. Because a significant number of FMPs operate very near the hydrocarbon dew point, there is a high potential for small amounts of liquid to flow through the meter. These liquids will typically consist of the heavier hydrocarbon components that contain high heating values. The use of membranes or filters in the sampling probe could block these liquids from entering the sampling system and would result in heating values lower than the actual heating value of the fluids passing through the meter. This would result in a bias that would be in violation of proposed § 3175.30(c).

Proposed § 3175.112(d) would set standards for the sample tubing which are based on API MPMS 14.1 and GPA 2166. To avoid reactions with potentially corrosive elements in the gas stream, the sample tubing can be made only from stainless steel or Nylon 11. Materials such as carbon steel can react with certain elements in the gas stream and alter the composition of the gas.

As specified in Table 4 in proposed § 3175.110, marginal-volume FMPs are exempt from all requirements in proposed § 3175.112 because, based on BLM experience with this level of production, a requirement to install or relocate a sample probe in marginal-volume FMPs could cause the well to be shut in.

§ 3175.113 Spot Samples—General Requirements

Proposed § 3175.113(a) would provide an automatic extension of the time for the next sample if the FMP were not flowing at the time the sample was due. Sampling a non-flowing meter would not provide any useful data. A sample would be required to be taken within 5 days of the date the FMP resumed flow.

Proposed § 3175.113(b) would require the operator to notify the BLM at least 72 hours before gas sampling. A 72-hour notification period is proposed to allow sufficient time for the BLM to arrange schedules as necessary to be present when the sample is taken.

Proposed § 3175.113(c) would establish requirements for sample cylinders used in spot or composite sampling. Proposed § 3175.113(c)(1) and (2) would adopt requirements for cylinder construction material and minimum capacity that are based on API and GPA standards.

Proposed § 3175.113(c)(3) would require that sample cylinders be cleaned according to GPA standards. This proposed section also would require documentation of the cylinder cleaning.

It is important to be able to verify that sample cylinders are clean before sampling to avoid contaminating a sample. Therefore, the BLM is seeking comment on the practicality and cost of installing a physical seal on the sample cylinder as proposed in § 3175.113(c)(4), or on other methods that the BLM could use to verify the cylinders are clean. The BLM is not aware of any industry standard or common industry practice that requires a seal to be used.

Proposed § 3175.113(d) would set standards for spot sampling using a portable gas chromatograph. This section primarily addresses the sampling aspects; the analysis requirements are prescribed in proposed § 3175.118. Both the GPA and API recognize that the use of sampling separators, while sometimes necessary for ensuring that liquids do not enter the gas chromatograph, can also cause significant bias in heating value if not used properly. Proposed § 3175.113(d)(1) would adopt GPA standards for the material of construction, heating, cleaning, and operation of sampling separators. It would also require documentation that the sample separator was cleaned as required under GPA 2166–05 Appendix A.

Proposed § 3175.113(d)(2) would require the filter at the inlet to the gas chromatograph to be cleaned or replaced before taking a sample. Industry standards do not provide specific requirements for how often the filter should be cleaned or replaced; however, a contaminated filter could bias the heating value.

Proposed § 3175.113(d)(3) would require the sample line and the sample port to be purged before sealing the connection between them. This requirement was derived from GPA 2166–05, which requires a similar purge when sample cylinders are being used. The purpose of this requirement is to disperse any contaminants that may have collected in the sample port and to purge any air that may otherwise enter the sample line.

Proposed § 3175.113(d)(4) would require portable gas chromatographs to adhere to the same minimum standards as laboratory gas chromatographs under proposed § 3175.118.

Proposed § 3175.113(d)(5) would prohibit the use of portable gas chromatographs if the flowing pressure at the sample port was less than 15 psig, which can affect accuracy of the device. This proposed requirement is based on GPA 2166–05.

§ 3175.114 Spot Samples—Allowable Methods

Proposed § 3175.114 would adopt three spot sampling methods using a cylinder and one method using a portable gas chromatograph. The three allowable methods using a cylinder were selected for their ability to accurately obtain a representative gas sample at or near the hydrocarbon dew point, the relative effectiveness of the method, and the ease of obtaining the sample. Because the BLM determined that the procedures required by either GPA or API standards were clear and enforceable as written, the BLM proposes to adopt them verbatim.

The most common method currently in use at points of royalty settlement for Federal and Indian leases is the ''Purging—Fill and Empty Method,'' which is one of the methods that would be allowed in the proposed rule; therefore, it is not expected that this requirement would result in any significant changes to current industry practice. Proposed § 3175.114(a) would also allow the helium ''pop'' method and the floating piston cylinder method. The fourth proposed spot sampling method (proposed § 3175.114(a)(4)) is the use of a portable gas chromatograph, which is discussed in proposed § 3175.113(d). Proposed § 3175.114(d) would provide that the BLM would post other approved methods on its Web site.

Proposed § 3175.114(b) would allow the use of a vacuum gathering system when the operator uses a purging-fill and empty method or a helium ''pop'' method and when the flowing pressure is less than or equal to 15 psig. Of the four spot sampling methods allowed in this section, API 14.1.12.10 recommends that only the purging-fill and empty method and the helium ''pop'' method be used in conjunction with the vacuum gathering system. As a result, neither the floating piston cylinder method nor the portable gas chromatograph method would be allowed in conjunction with a vacuum gathering system.

§ 3175.115 Spot Samples—Frequency

Proposed § 3175.115(a) would require that gas samples at low-volume FMPs be taken at least every 6 months. Gas samples would have to be taken at marginal-volume FMPs at least annually, which is the same requirement as in Order 5. The BLM determined that sampling no more often than annually has the potential for biasing the heating value. If, for example, an annual sample was always taken in January when the ambient temperature is low, there could be a higher possibility that the heavier components could liquefy and bias the composition. This would not be consistent with proposed § 3175.30(c), which would require the absence of significant bias in low-volume FMPs. The BLM believes that sampling at low-volume FMPs at least every 6 months would reduce the potential for bias.

Proposed § 3175.115(a) would require spot samples at high- and very-high-volume FMPs to be taken at least every 3 months and every month, respectively, unless the BLM determines that more frequent analysis is required under § 3175.115(b). The sampling frequencies presented in Table 4 were developed as part of the ''BLM Gas Variability Study Final Report,'' May 21, 2010. The study used 1,895 gas analyses from 217 points of royalty settlement and concluded that heating value variability is not a function of reservoir type, production type, age, richness of the gas, flowing temperature, flow rate, or a number of other factors that were included in the study. Instead, the study found that heating value variability appeared to be unique to each meter. The BLM believes that the lack of correlation with at least some of the factors identified here could be a symptom of poor sampling practice in the field. The study also concluded that heating-value uncertainty over a period of time is manifested by the variability of the heating value, and more frequent sampling would lessen the uncertainty of an average annual heating value, regardless of whether the variability is due to actual changes in gas composition or to poor sampling practice.

The frequencies shown in Table 4 for high- and very-high-volume FMPs are typical of the sampling frequency required to obtain the heating value certainty levels that would be required in proposed § 3175.30(b)(1) and (2). Proposed § 3175.115(b) would allow the BLM to require a different sampling frequency if analysis of the historic heating value variability at a given FMP results in an uncertainty that exceeds what would be required in proposed § 3175.30(b)(1) and (2). Under proposed § 3175.115(b), the BLM could increase or decrease the required sampling frequency given in Table 4. To implement this proposed requirement, the BLM would develop a database called the Gas Analysis Reporting Verification System (GARVS). This database would be used to collect gas sampling and analysis information from Federal and Indian oil and gas operators. GARVS would perform analysis of that data to implement other proposed gas sampling requirements as well. The sample frequency calculation in GARVS would be based on the heating values entered into the system under proposed § 3175.120(f). GARVS would round down the calculated sampling frequency to one of seven possible values: Every week, every 2 weeks, every month, every 2 months, every 3 months, every 6 months, or every 12 months. The BLM would notify the operator of the new required sampling frequency.

Proposed § 3175.115(b)(2) would clarify that the new sampling frequency would remain in effect until a different sampling frequency is justified by an increase or decrease of the variability of previous heating values.

Proposed § 3175.115(b)(3) would limit the maximum sampling frequency to once per week. If weekly sampling would still not be sufficient to achieve the certainty levels that would be required under 3175.30(b)(1) or (2), then under 3175.115(b)(4), the BLM could require the operator to install a composite sampling system or an on-line gas chromatograph.

Proposed § 3175.115(c) would establish the maximum allowable time between samples for the range of sampling frequencies that the BLM would require, as shown in Table 5. This would allow some flexibility for situations where the operator is not able to access the location on the day the sample was due, although the total number of samples required every year would not change. For example, if the required sampling frequency was once per month, the operator would have to obtain 12 samples per year. If the operator took a sample on January 1st, the operator would have until February 14th to take the next sample (45 days later).

If a composite sampling system or on-line gas chromatograph is required by the BLM under proposed § 3175.115(b)(5) or opted for by the operator, proposed § 3175.115(d) would require that device to be operational within 30 days after the due date of the next sample. For example, if the required sampling frequency was weekly and the next sample was due on February 18th, the composite sampling system or on-line gas chromatograph would have to be operational by March 18th. The operator would not be required to take spot samples within this 30-day time period. The BLM considers both composite sampling and the use of on-line gas chromatographs to be superior to spot sampling, as long as they are installed and operated under the requirements in proposed §§ 3175.116 and 3175.117, respectively.

Proposed § 3175.115(e) would address meters where a composite sampling system or on-line gas chromatograph was removed from service. In these situations, the spot sampling frequency for that meter would revert to that required under proposed § 3175.115(a) and (b).

§ 3175.116 Composite Sampling Methods

Proposed § 3175.116 would set standards for composite sampling. The BLM used API MPMS 14.1.13.1 as the basis for § 3175.116(a) through (c). Proposed § 3175.116(d) would require the composite sampling system to meet the heating-value uncertainty requirements of proposed § 3175.30(b).

§ 3175.117 On-Line Gas Chromatographs

Proposed § 3175.117 would set standards for online gas chromatographs. Because there are few industry standards for these devices, the BLM is particularly interested in comments on these proposed requirements or whether different or alternative standards should be adopted. The BLM is aware that API MPMS 22.6, a testing protocol for gas chromatographs, is nearing completion and is requesting comments on whether it should be incorporated by reference in the final rule.

§ 3175.118 Gas Chromatograph Requirements

Proposed § 3175.118 would establish requirements for the analysis of gas samples. Under proposed § 3175.118(a), these minimum standards would apply to all gas chromatographs, including portable, online, and stationary laboratory gas chromatographs. These requirements are derived primarily from two industry standards: GPA 2166–00 and GPA 2198–03.

Proposed § 3175.118(b) would require that gas samples be run until three consecutive runs have met the repeatability standards stated in GPA 2261–00. Obtaining three consistent analysis results would ensure that any contaminants in the gas chromatograph system have been purged and that system repeatability is achieved. This proposed section would also require that the sum of the un-normalized mole percents of the gas components detected are between 99 percent and 101 percent to ensure proper functioning of the gas chromatograph system. This requirement is based on GPA 2261–00. The mole percent is the percent of a particular molecule in a gas sample. For example, if there were 2 propane molecules for every 100 molecules in a gas sample, the mole percent of propane would be 2.

Proposed § 3175.118(c) would set a minimum frequency for verification of gas chromatographs. More frequent verifications would be required for portable gas chromatographs because these devices may be exposed to field conditions such as temperature changes, dust, and transportation effects. All of these conditions have the potential to affect calibration. In contrast, laboratory gas chromatographs are not exposed to these conditions; therefore, they would not need to be verified as often.

Proposed § 3175.118(d) would require that the gas used for verification be different than the gas used for calibration. This requirement is proposed because it is relatively easy to alter the composition of a reference gas if it is not handled properly. An errant reference gas used to calibrate a gas chromatograph would not be detected if the same gas is used for verification, which could lead to a biased heating value.

Proposed § 3175.118(e) would require a calibration of the gas chromatograph if the specified repeatability could not be achieved during a verification. The calibration would have to comply with GPA 2261–00, Section 9. This section would clarify when a calibration is needed.

Proposed § 3175.118(f) would require the equivalent of an as-left verification after the gas chromatograph was calibrated. A final verification would ensure that the calibration of the gas chromatograph was successful.

Proposed § 3175.118(g) would prohibit the use of a gas chromatograph that has not been verified under § 3175.118(e). This requirement would ensure that gas samples from FMPs are analyzed with gas chromatographs that will yield accurate heating values.

Proposed § 3175.118(h) would adopt the calibration gas standards of GPA 2198–03. This requirement would ensure the accuracy of the gas measurement used to calibrate gas chromatographs.

Proposed § 3175.118(i) would require documentation of gas chromatograph verification to be retained as required under the record-retention requirements in proposed § 3170.7, published previously (80 FR 40768 (July 13, 2015)). For portable gas chromatographs, the documentation must be available onsite. The purpose of the latter requirement is that it would allow the BLM to inspect the verification documents while witnessing a spot sample that is taken with a portable gas chromatograph. If the verification had not been performed at the frequency required in proposed § 3175.118(c)(1), or did not meet the standards of § 3175.118(e), the gas chromatograph would not be allowed to analyze the sample.

§ 3175.119 Components to Analyze

Proposed § 3175.119 would establish the minimum gas components which the operator must analyze. Section 3175.119(a) would require an analysis through hexane+ for all FMPs and would also include carbon dioxide and nitrogen analysis. Analysis through hexane+ is common industry practice and does not represent a significant change from existing procedures. Although components heavier than hexane exist in gas streams, these components are typically included in the hexane+ concentration given by the gas chromatograph. Under proposed § 3175.126(a)(3), the heating value of hexane+ would be derived from an assumed gas mixture consisting of 60 mole percent hexane, 30 mole percent heptane, and 10 mole percent octane. At concentrations of hexane+ below the threshold given in proposed § 3175.119(b), the uncertainty due to the assumed gas mixture given in § 3175.126(a)(3) does not significantly contribute to the overall uncertainty in heating value and would not significantly affect royalty.

Proposed § 3175.119(b) would require an extended analysis of the gas sample, through nonane+, if the concentration of hexane+ from the standard analysis is 0.25 mole percent or greater. This requirement would not apply to marginal-volume FMPs or low-volume FMPs. The threshold of 0.25 mole percent was derived through numerical simulation of the assumed composition of hexane+ (60 mole percent hexane, 30 mole percent heptanes, and 10 mole percent octane) compared to randomly generated values of hexane, heptanes, octane, and nonane. The numerical simulation showed that the additional uncertainty of the fixed hexane+ mixture required in § 3175.126(a)(3) does not significantly add to the heating value uncertainties required in § 3175.30(b), until the mole percent of hexane+ exceeds 0.25 mole percent. The BLM is seeking data that confirms or refutes the results of our numerical simulation. Specifically, we are seeking data comparing heating values determined with a hexane+ analysis with heating values of the same samples determined through an extended analysis.

§ 3175.120 Gas Analysis Report Requirements

Proposed § 3175.120 would establish minimum standards for the information that must be included in a gas analysis report. This information would allow the BLM to verify that the sampling and analysis comply with the requirements proposed in § 3175.110, and would enable the BLM to independently verify the heating value and relative density used for royalty determination.

Proposed § 3175.120(b) would require that gas components not tested be annotated as such on the gas analysis report. It is common practice for industry to include a mole percent for each component shown on a gas analysis report, even if there was no analysis run for that component. For example, the gas analysis report might indicate the mole percent for hydrogen sulfide to be ''0.00 percent,'' when, in fact, the sample was not tested for hydrogen sulfide. The BLM believes this practice to be potentially misleading.

Proposed § 3175.120(c) and (d) would adopt API MPMS 14.5 and 14.2, respectively. The BLM believes that these API standards are appropriate for heating value, relative density, and base supercompressibility calculations.

Proposed § 3175.120(e) would require operators to submit all gas analysis reports to the BLM within 5 days of the due date for the sample. For high-volume and very-high-volume FMPs, the gas analyses would be used to calculate the required sampling frequencies under § 3175.115(c). Requiring the submission of all gas analyses would allow the BLM to verify heating-value and relative-density calculations and it would allow the BLM to determine operator compliance with other sampling requirements in proposed § 3175.110. The method of determining gas sampling frequency for high-volume and very-high-volume FMPs assumes a random data set. The intentional omission of valid gas analyses would invalidate this assumption and could result in a biased annual average heating value. This could be considered tampering with a measurement process under proposed 43 CFR 3170.4, published previously. See 80 FR 40768 (July 13, 2015).

Proposed § 3175.120(f) would require operators to submit all gas analysis reports to the BLM using the GARVS online computer system that the BLM is developing. The GARVS would be implemented before the effective date of the final rule. Operators would be required to submit all gas analyses electronically, unless the operator is a small business, as defined by the U.S. Small Business Administration, and does not have access to the Internet.

§ 3175.121 Effective Date of a Spot or Composite Gas Sample

Proposed § 3175.121 would establish an effective date for the heating value and relative density determined from spot or composite sampling and analysis. Section 3175.121(a) would establish the effective date as the date on which the spot sample was taken unless it is otherwise specified on the gas analysis report. For example, industry will sometimes choose the first day of the month as the effective date to simplify accounting.

While the BLM believes this is an acceptable practice, there is a need to place limits on the length of time between the sample date and the effective date based on inconsistencies found as part of the gas variability study discussed earlier. Proposed § 3175.121(b) would establish that the effective date could be no later than the first day of the month following the date on which the operator received the laboratory analysis of the sample. This would account for the delay that often occurs between taking the sample, obtaining the analysis, and applying the results of the analysis. If, for example, a sample were taken toward the end of March, the results of the analysis may not be available until after the first of April. The proposed requirement would allow the effective date to be the first of May. Based on the gas variability study conducted by the BLM, the timing of the effective date of the sample is less important than the timing of the samples taken over the year.

Proposed § 3175.121(c) would require the effective dates of a composite sample to coincide with the time that the sample cylinder was collecting samples. A composite sampling system takes small samples of gas over the course of a month or some other time period, and places each small sample into one cylinder. At the end of that time period, the cylinder contains a gas sample that is representative of the gas that flowed through the meter over that time period. Therefore, the heating value and relative density determined from that sample are valid only for the time period the cylinder was collecting samples.

§ 3175.125 Calculation of Heating Value and Volume

Proposed § 3175.125(a) would be a new requirement that would define how the operator must calculate heating value. Proposed paragraphs (a)(1) and (a)(2) would define the calculation of gross and real heating value. Although this would be a new requirement, the calculation and reporting of gross and real heating value is standard industry practice.

Proposed § 3175.125(b)(1) would establish a standard method for determining the average heating value to be reported for a lease, unit PA, or CA, when the lease, unit PA, or CA contains more than one FMP. Consistent with current ONRR guidance (Minerals Production Reporter Handbook, Release 1.0, 05/09/01, Glossary at 14), the proposed method requires the use of a volume-weighted average heating value to be reported. Proposed § 3175.125(b)(2) would establish a requirement for determining the average heating value of an FMP when the effective date of a gas analysis is other than the first of the month. The proposed methodology also requires a volume-weighted average for determining the heating value to be reported. Although this is not specifically addressed in the Reporter Handbook, the method is consistent with the volume-weighted average proposed for multiple FMPs.

§ 3175.126 Reporting of Heating Value and Volume

Proposed § 3175.126 would be a new requirement that would define the conditions under which the heating value and volume would be reported for royalty purposes. The reporting of gross and real heating value in § 3175.126(a) would be consistent with standard industry practice.

The proposed requirement to report ''dry'' heating value (no water vapor) in proposed § 3175.126(a)(1) would be a change for some operators because gas sales contracts often call for ''wet'' or saturated heating values to be used. The BLM has determined that ''wet'' heating values almost always bias the heating value to the low side because the definition of ''wet'' heating value assumes the gas is saturated with water vapor at 14.73 psi and 60°F. If the actual flowing pressure of the gas is greater than 14.73 psi or the actual flowing temperature is less than 60°F, the use of a ''wet'' heating value will overstate the amount of water vapor that can be physically present, and, therefore, understate the heating value of the gas. Therefore, the BLM is proposing to require a ''dry'' heating value determination basis unless the actual amount of water vapor is physically measured and reported on the gas analysis report. This requirement is consistent with an existing provision in ONRR regulations at 30 CFR 1202.152(a)(1)(i) which requires the heating value to be reported at the same level of water saturation as volume. Established BLM practice is reflected in BLM Washington Office Instruction Memorandum (IM) 2009–186, dated July 28, 2009, which explains:

> This IM establishes the BLM policy that, when verifying the heating value reported on OGOR–B, the dry reporting basis from the gas analysis must be used unless the water vapor content was determined as part of the analysis, in which case the real or actual heating value will be used. If it is found that the operator has been reporting on the wrong basis, it must be resolved per the instructions in IM 2009–174, ''Request for Modified or Missing Oil and Gas Operations Report from the Minerals Management Service.'' The description of what was found must state (for typical gas analyses): ''Gas volumes have been determined based on the assumption that no water vapor is present. Heating value must be based on the same degree of water saturation. The heating value must, therefore, be reported on a dry basis.''

The Minerals Management Service (MMS) regulations (30 CFR 202.152(a)(1)(i)) [6] state:

> *''Report gas volumes and British thermal unit (Btu) heating values, if applicable, under the same degree of water saturation.''*

The BLM has interpreted this to mean a dry or real/actual reporting basis. In order to determine gas volumes, the relative density (or specific gravity) of the gas must be known. The relative density is determined from the same gas analyses that are used to determine heating value. Because water vapor cannot be detected by most gas chromatographs, the vast majority of gas analyses do not include water vapor as a constituent of the gas sample even if some water vapor is present. While adjustments to the heating value of the gas can be made based on assumptions of water saturation, relative density is rarely adjusted to account for the water vapor that may or may not be present. In essence, the relative density used to determine volume is almost always on a ''dry'' basis because water vapor is excluded from the calculation. The ''dry'' relative density is included in the calculations to determine gas flow rate and gas volume; therefore, the volume is ultimately determined on a ''dry'' basis. According to the MMS regulation cited above, if volume is reported on a ''dry'' basis, heating values must also be reported on a dry basis.

In the rare instance where water vapor content is actually measured and included in the gas analysis, the relative density calculation includes the actual water vapor content. This would result in volume being

[6] Now ONRR regulations at 30 CFR 1202.152(a)(1)(i).

determined on a ''real'' or ''actual'' basis. If volume is determined on a real or actual basis, then the heating value must also be reported on a real or actual basis according to the MMS regulations.

IM 2009–186 at 2.

The BLM would consider allowing an adjustment in heating value for assumed water-vapor saturation at flowing pressure and temperature (sometimes referred to as ''as delivered'') in the final rule if sufficient data is presented in the public comments on this proposed rule that shows this to be a valid assumption and under what flowing conditions the assumption is valid. Alternatively, if sufficient data is supplied, the BLM may consider adjusting volumes for water vapor in lieu of a heating value adjustment. The BLM will review information and comments submitted to determine if an approach different from the one proposed is justified.

The proposed section also defines the acceptable methods to measure water vapor: A chilled mirror, a laser detection system, and other methods that the BLM may approve through the PMT. Stain tubes and other similar measurement methods would not be allowed because of the high degree of uncertainty inherent in these devices.

Proposed § 3175.126(a)(2) would require the heating value to be reported at 14.73 psia and 60°F. Although this was not required in Order 5, it is currently required by ONRR regulations at 30 CFR 1202.152(a)(1)(ii).

The composition of hexane+ that would be required for heating value and relative density calculation is given in § 3175.126(a)(3). This composition was based on examples shown in API MPMS 14.5, Annex B.

Proposed § 3175.126(b) would define the volume of gas that must be reported for royalty purposes. Proposed § 3175.126(b)(1) would prohibit the practice of adjusting volumes for assumed water-vapor content, since this is currently done in some cases in lieu of adjusting the heating value for water-vapor content. This results in the volume being underreported. The BLM may consider in the final rule allowing for water-vapor adjustment if sufficient data are submitted during the public comment period to support an adjustment, as discussed above. This would be a new requirement.

Proposed § 3175.126(b)(2) would require the unedited volume on a quantity transaction record (EGM systems) or an integration statement (mechanical recorders) to match the volume reported for royalty purposes, unless edits to the data could be justified and documented by the operator. This would be a new requirement and it is needed for verification of production.

Proposed § 3175.126(c) would establish new requirements for edits and adjustments to volume or heating value. Section 3175.126(c)(1) would allow for estimating volumes or heating values if measuring equipment is out of service or malfunctioning. Although this is similar to a requirement in Order 5, additional requirements would be added to prescribe how the estimates would be determined.

Proposed § 3175.126(c)(2) would require documentation justifying all edits made to data affecting volumes or heating values reported on the OGORs. While the BLM recognizes that meter malfunctions and other factors can necessitate editing the data to obtain a more correct volume, this section would require operators to thoroughly justify and document the edits made. This would include quantity transaction records and integration statements. The operator would retain the documentation as required under proposed § 3170.7 and would submit it to the BLM upon request. This would be a new requirement.

Proposed § 3175.126(c)(3) would require that any edited data be clearly identified on reports used to determine volumes or heating values reported on the OGORs and cross-referenced to the documentation required in 3175.126(c)(2). This would include quantity transaction records and integration statements. This would be a new requirement.

Proposed § 3175.126(c)(4) would require the amendment of the OGOR reports submitted to ONRR in the case of an inaccuracy discovered in an FMP. Although this would be a new requirement, it is similar to the requirement for correcting calibration errors in Order 5.

§ 3175.130 Transducer Testing Protocol

Proposed § 3175.130 would establish a testing protocol for differential-pressure, static-pressure, and temperature transducers used in conjunction with differential-flow meters at FMPs. This would be a new requirement. This section would be added to implement the requirements proposed in § 3175.131(a) for flow-rate uncertainty limits. To determine flow-rate uncertainty, it is necessary to first determine the uncertainty of the variables that go into the calculation of flow rate. For differential flow meters, these variables include differential pressure, static pressure, and flowing temperature. Transducers (secondary devices) derive these variables by measuring, among other things, the pressure drop created by the primary device (*e.g.,* an orifice plate). Therefore, the uncertainty of these variables is dependent on the uncertainty of the transducer's ability to convert the physical parameters measured into a digital value that the flow computer can use to calculate flow rate and, ultimately, volume.

Currently, methods used to determine uncertainty (*i.e.,* the BLM Uncertainty Calculator) rely on performance specifications published by the transducer manufacturers. However, the methods that manufacturers use to determine and report these performance specifications are typically proprietary, performed in-house, and the BLM cannot verify them. In addition, the BLM believes that there is little consistency among manufacturers regarding the standards and methods used to establish and report performance specifications.

The testing procedures in proposed §§ 3175.131 through 3175.135 are based, in large part, on testing procedures published by the International Electrotechnical Commission (IEC). Some of these standards are already used by several transducer manufacturers; however it is unknown which manufacturers use which standards or to what extent they do so.

§ 3175.131 General Requirements for Transducer Testing

Proposed § 3175.131(a) would establish standards for test facilities qualified to perform the transducer-testing protocol. Proposed § 3175.130(a)(1) would require tests to be carried out by a lab that is not affiliated with the manufacturer to avoid any real or perceived conflict of interest. Traceability to the NIST proposed in § 3175.131(a)(2) is based on IEC Standard 1298–1, section 7.1.

Proposed § 3175.131(b) would require that the testing protocol be applied to each make, model, and URL of transducers used at FMPs, to ensure that any transducer with the potential to have unique performance characteristics is tested.

In general, the testing requirements in paragraphs (c) through (h) of this proposed section are based on IEC standard 1298–1, Section 6.7. While the IEC does not specify the minimum number of devices required for a representative number, the BLM is proposing (in paragraph (b)(1)) that at least five transducers be tested to ensure testing of a statistically representative sample of the transducers coming off the assembly line. The BLM specifically seeks comments on whether the testing of five transducers is a statistically representative sample.

§§ 3175.132 and 3175.133 Testing of Reference Accuracy and Influence Effects

Proposed §§ 3175.132 and 3175.133 would establish specific testing requirements for reference accuracy and influence effects. These requirements are based on the following IEC standards: IEC 1298–1, IEC 1298–2, IEC 1298–3, and IEC 60770–1.

§ 3175.134 Transducer Test Reporting

Proposed § 3175.134 would require documentation of the testing and the submission of the documentation to the PMT. The PMT would use the documentation to determine the uncertainty and influence effects of each make, model, and range of transducer tested.

§ 3175.135 Uncertainty Determination

Proposed § 3175.135 would establish a method of deriving reference uncertainty and quantifying influence effects from the tests required by this protocol. The methods for determining reference uncertainty are based on IEC Standard 1298–2, Section 4.1.7. While the IEC standards define the methods to be used for influence effect testing, no specific methods are given to quantify the influence effects; therefore, the BLM developed statistical methods to determine zero-based effects and span-based effects. In addition, all uncertainty calculations use a ''student t-distribution'' to account for the small number of transducers of a particular make, model, URL, and turndown, to be tested.

After a transducer has been tested under proposed §§ 3175.130 through 3175.134, the PMT would review the results. The BLM would list the approved transducers for use at FMPs (see § 3175.43), and list the make, model, URL, and turndown of approved transducers on the BLM Web site along with any operating limitations or other conditions.

§ 3175.140 Flow Computer Software Testing Protocol

Proposed § 3175.140 would provide that the BLM would approve a particular version of flow-computer software if the testing is performed under the testing protocol in proposed §§ 3175.141 through 3175.144, to ensure that calculations meet API standards. Unlike the testing protocol for transducers proposed in § 3175.130, which is used to derive performance specifications, the testing protocol for flow computers would establish pass-fail criteria. This would be a new requirement. Testing would only be required for those software revisions that affect volume or flow rate calculations, heating value, or the audit trail.

§ 3175.141 General Requirements for Flow-Computer Software Testing

The testing procedures in this section are based, in large part, on a testing protocol in API MPMS 21.1, Annex E.

Proposed § 3175.141(a) would require that all testing be done by an independent laboratory to avoid any real or perceived conflict of interest in the testing.

Proposed § 3175.141(b)(1) would require that each make, model, and software version tested must be identical to the software version installed at an FMP. Proposed § 3175.141(b)(2) would require that each software version be given a unique identifier, which would have to be part of the display (see proposed § 3175.101(b)(4)(ii)) and the configuration log (see proposed § 3175.104(b)(2)) to allow the BLM to verify that the software version has been tested under the protocol proposed in this section.

Proposed § 3175.141(c) would provide that input variables may be either applied directly to the hardware registers or applied physically to a transducer. In the latter event, the values received by the hardware register from the transducer (which are subject to some uncertainty) must be recorded.

Proposed § 3175.141(d) would establish a pass-fail criteria for the software testing. The digital values obtained for the testing in proposed §§ 3175.142 and 3175.143 would be entered into reference software approved by the BLM, and the resulting values of flow rate, volume, integral value, flow time, and averages of the live input variables would be compared to the values determined from the software under test. A maximum allowable error of 50 parts per million (0.005 percent) would be established in proposed § 3175.141(d)(2).

§ 3175.142 Required Static Tests

Proposed § 3175.142(a) would set out six required tests to ensure that the instantaneous flow rate was being properly calculated by the flow computer. The parameters for each of the six tests set out in Tables 6 and 7 in this proposed section are designed to test various aspects of the calculations, including supercompressibility, gas expansion, and discharge coefficient over a range of conditions that could be encountered in the field.

Proposed § 3175.142(b) would test the ability of the software to accurately accumulate volume, integral value, and flow time, and calculate average values of the live input variables over a period of time with fixed inputs applied.

Proposed § 3175.142(c) would test the ability of the event log to capture all required events, test the software's ability to handle inputs to a transducer that are beyond its calibrated span, and test the ability of the software to record the length of any power outage that inhibited the computer's ability to collect and store live data.

§ 3175.143 Required Dynamic Tests

Proposed § 3175.143 would establish required dynamic tests that would test the ability of the software to accurately calculate volume, integral value, flow time, and averages of the live input variables under dynamic flowing conditions. The tests are designed to simulate extreme flowing conditions and include a square wave test, a sawtooth test, a random test, and a long-term volume accumulation test. A square wave test applies an input instantaneously, holds that input constant for a period of time and then returns the input to zero instantaneously. A sawtooth test increases an input over time until it reaches a maximum value, and then decreases that input over time until it reaches zero. A random test applies inputs randomly.

§ 3175.144 Flow-computer Software Test Reporting

After a software version has been tested under proposed §§ 3175.141 through 3175.143, the PMT would review the results. If the test was deemed successful, the BLM would approve the use of the software version and flow computer and would list the make and model of the flow computer, along with the software version tested, on the BLM Web site (see proposed § 3175.44).

§ 3175.150 Immediate Assessments

Proposed § 3175.150 would identify 10 specific violations that would be subject to elevated civil assessment amounts, as opposed to being subject to the provisions for major and minor violations generally under current guidance. The BLM's existing regulations at 43 CFR 3163.1 and Order 3 establish assessments that an operator or operating rights owner may be subject to for failure to comply with the terms and conditions of a lease or any applicable legal requirements. The authority for the BLM to impose these assessments was explained in the preamble to the final rule in which 43

CFR 3163.1 was originally promulgated in 1987:

> The provisions providing assessments have been promulgated under the Secretary of the Interior's general authority, which is set out in Section 32 of the Mineral Leasing Act of 1920, as amended and supplemented (30 U.S.C. 189), and under the various other mineral leasing laws. Specific authority for the assessments is found in Section 31(a) of the Mineral Leasing Act (30 U.S.C. 188(a)), which states, in part ''. . . the lease may provide for resort to appropriate methods for the settlement of disputes or for remedies for breach of specified conditions thereof.'' All Federal onshore and Indian oil and gas lessees must, by the specific terms of their leases which incorporate the regulations by reference, comply with all applicable laws and regulations. Failure of the lessee to comply with the law and applicable regulations is a breach of the lease, and such failure may also be a breach of other specific lease terms and conditions. Under Section 31(a) of the Act and the terms of its leases, the BLM may go to court to seek cancellation of the lease in these circumstances. However, since at least 1942, the BLM (and formerly the Conservation Division, U.S. Geological Survey), has recognized that lease cancellation is too drastic a remedy, except in extreme cases. Therefore, a system of liquidated damages was established to set lesser remedies in lieu of lease cancellation. The BLM recognizes that liquidated damages cannot be punitive, but are a reasonable effort to compensate as fully as possible the offended party, in this case the lessor, for the damage resulting from a breach where a precise financial loss would be difficult to establish. This situation occurs when a lessee fails to comply with the operating and reporting requirements. The rules, therefore, establish uniform estimates for the damages sustained, depending on the nature of the breach. 52 FR 5384 (February 20, 1987).

In sum, these civil assessments are intended to reflect the costs incurred by the BLM associated with identifying these violations and ensuring compliance with applicable remedial requirements.

The existing regulations establish assessments for major and minor violations generally and identify four violations that warrant immediate assessments. Those violations and corresponding assessments are: (1) Failure to install a blowout preventer or other equivalent well-control equipment, $500 per day, not to exceed $5,000; (2) Drilling without approval or causing surface disturbance on Federal or Indian surface preliminary to drilling without approval, $500 per day, not to exceed $5,000; (3) Failure to obtain prior approval of a well-abandonment plan, $500 total; and, in Order 3, (4) Removing a Federal seal without BLM approval, $250. These assessments are in addition to the civil penalties authorized under Section 109 of the Federal Oil and Gas Royalty Management Act (FOGRMA), 30 U.S.C. 1719.

As explained in connection with the changes to 43 CFR 3163.1 being proposed as part of this rule, the BLM is proposing that all civil assessments under § 3163.1 or proposed subparts 3173, 3174, and 3175, should be immediate. With respect to the requirements of the proposed subpart 3175, the proposed rule would identify 10 specific violations that would be subject to elevated assessments as opposed to being subject to the amounts specified under 43 CFR 3163.1 for major and minor violations. These violations would be subject to a $1,000 assessment and include the following:

1. New FMP orifice plate inspections were not conducted as required under proposed § 3175.80(c);
2. Routine FMP orifice plate inspections were not conducted as required under proposed § 3175.80(d);
3. Visual meter-tube inspections were not conducted as required under proposed § 3175.80(h);
4. Detailed meter-tube inspections were not conducted as required under proposed § 3175.80(i);
5. An initial mechanical recorder verification was not conducted as required under proposed § 3175.92(a);
6. Routine mechanical recorder verifications were not conducted as required under proposed § 3175.92(b);
7. An initial EGM system verification was not conducted as required under proposed § 3175.102(a);
8. Routine EGM system verifications were not conducted as required under proposed § 3175.102(b);
9. Spot samples for low-volume and marginal-volume FMPs were not taken as required under proposed § 3175.115(a); and
10. Spot samples for high- and very-high-volume FMPs were not taken as required under proposed § 3175.115(a) and (b).

The BLM chose the $1,000 figure because it approximates the average of what it would cost the agency, based on an analysis of its costs, to identify and document each of the aforementioned violations and verify that the necessary remedial actions have been completed. The BLM seeks comment on whether these assessments should be higher or lower or what other factors it should consider in setting them.

Miscellaneous Changes to Other BLM Regulations in 43 CFR Part 3160

As noted at the beginning of this section-by-section analysis, the BLM is proposing other changes to provisions in 43 CFR part 3160. Some of the changes have been discussed already. The remaining proposed revisions are those noted here.

1. Section 3162.7–3, Measurement of gas, would be rewritten to reflect this proposed rule.
2. Section 3163.1, Remedies for acts of noncompliance, would be rewritten in part in several respects. As explained in connection with proposed revisions to proposed § 3175.150, the BLM's existing regulations contain provisions authorizing the BLM to impose assessments on operators and operating rights owners for violation of the terms and conditions of their lease or any other applicable law. These assessments are a form of liquidated damages designed to capture the costs incurred by the BLM in identifying and responding to these violations. These assessments are not intended to be punitive.

The existing regulations establish two categories of assessments. There is a general category, which authorizes assessments for major and minor violations. Those assessments may be imposed only after a written notice that provides a corrective or abatement period, subject to the limitations in existing paragraph (c).[7] As discussed with respect to proposed § 3175.150, there are also currently four specific violations where the BLM's existing rules authorize the imposition of immediate assessments. The BLM is proposing to modify this approach. Rather than having certain specific violations be subject to immediate assessments, while major and minor violations are only subject to assessments after notice and an opportunity to cure, the BLM is proposing that all assessments under § 3163.1 may be imposed immediately. The BLM believes that the notice and opportunity to cure currently specified for major and minor violations is unnecessary and represents an inefficient allocation of the BLM's inspection resources. The BLM's regulations governing oil and gas operations are clear and provide operators and other parties with ample notice of their responsibilities. As such, the BLM does not believe it is necessary to provide an additional corrective or abatement period before imposing an assessment for major or minor violations. This change will also result in administrative efficiencies. Under the

[7] 43 CFR 3163.1(c) provides that ''[a]ssessments under paragraph (a)(1) of this section shall not exceed $1,000 per day, per operating rights owner or operator, per lease. Assessments under paragraph (a)(2) of this section shall not exceed a total of $500 per operating rights owner or operator, per lease, per inspection.''

current regulations, the BLM has to first identify a violation; then, if the violation identified is not one of the small number of violations currently subject to immediate assessment, the BLM has to issue a notice identifying the violation and specifying a corrective period. The BLM then has to follow up and determine whether corrective actions have been taken in response to the notice before an assessment can be imposed. All of these steps cause the BLM to incur costs and occupy inspection resources.

Therefore, the BLM is proposing to revise paragraphs (a)(1) and (2) to allow the BLM to impose fixed assessments of $1,000 on a per-violation, per-inspection basis for major violations, and $250 on a per-violation, per-inspection basis for minor violations.[8] The revisions to paragraphs (a)(1) and (2) would maintain the BLM's discretion to impose such assessments on a case-by-case basis; however, the BLM is proposing to increase the assessments for major violations to $1,000 consistent with the other provisions proposed here as the nature of the violations are the same. The existing provisions found in subparagraphs 3163.1(a)(3) through (6) would remain unchanged.

The introductory language in paragraph (a) would also be revised to apply to ''any person'' and would no longer be limited to operating rights owners and operators. This proposed change would enable the agency to impose assessments directly on parties who contract with operating rights owners or operators to perform activities on Federal or Indian leases that violate applicable regulations, lease terms, notices, or orders in performing those activities, and thereby cause the agency to incur the costs to detect and remedy those violations. While the operating rights owner or operator is responsible for violations committed by contractors and therefore is subject to assessments for the contractor's non-compliance, the contractors themselves are also obligated to comply with applicable regulations, lease terms, notices, and orders. Thus, the BLM is proposing to revise the regulations to enable the agency to impose assessments directly on the party whose non-compliance imposes costs on the agency. (The discussion of the new immediate assessments in proposed § 3175.150 explains the authority for assessments of this kind.) The proposed change would also make § 3163.1(a) consistent with the proposed revision to § 3163.2.

Paragraph (b) in the current regulations identifies specific serious violations for which immediate assessments are imposed upon discovery without exception. These are: (1) Failure to install a blowout preventer or other equivalent well control equipment; (2) Drilling without approval or causing surface disturbance on Federal or Indian surface preliminary to drilling without approval; and (3) Failure to obtain approval of a plan for well abandonment prior to commencement of such operations. These assessments are already imposed immediately. Accordingly, no changes were required as a result of the proposed change in the general approach to assessments. The BLM has, however, proposed clarifications to paragraph (b) to make it consistent with the changes proposed for paragraph (a) and to acknowledge that certain assessments would be identified in proposed subparts 3173, 3174, and 3175.

In addition, the BLM proposes to revise the first two assessments found in paragraph (b) to make each of them flat assessments of $1,000 that would be imposed on a per-violation, per-inspection basis, instead of the current framework, which contemplates an assessment of $500 per day up to a maximum cap of $5,000. As explained in connection with § 3175.150, the BLM chose the $1,000 figure because it approximates the average cost to the agency to identify such violations. The BLM seeks comment on whether these assessments should be higher or lower or what other factors it should consider in setting them. Paragraph 3163.1(b)(3) would be unchanged by this proposed rule.

In connection with the proposed shift from assessments that accrue on a daily basis to ones that can be assessed on a per-violation, per-inspection basis, the daily limitations imposed by existing paragraph (c) would no longer be necessary. Therefore, paragraph (c) is proposed for deletion.

Existing paragraph (d), which provides that continued noncompliance subjects the operating rights owner or operator to civil penalties under § 3163.2 of this subpart, would be removed. Continued noncompliance may subject a party to civil penalties under § 3163.2 and the statute that it implements (Section 109 of FOGRMA, 30 U.S.C. 1719) regardless of whether the assessment regulation so provides, and therefore the requirements of paragraph (d) were determined to be redundant and unnecessary.

Finally, as a result of these changes, the current paragraph (e) would be re-designated as paragraph (c).

3. Section 3163.2, Civil penalties, would be rewritten in part in several respects. First, in connection with the recently proposed subpart 3173, 80 FR 40,768 (July 13, 2015), the BLM proposes to add new language and provisions to address purchasers and transporters who are not operating rights owners to make § 3163.2 consistent with the requirements of Section 109 of FOGRMA, 30 U.S.C. 1719, which subjects a purchaser or transporter to civil penalties if they fail to maintain and submit required records. As explained in the proposed rule for subpart 3173, this change resulted in the re-designation of paragraphs (a) and (b) of § 3163.2. The revisions proposed in this rule assume the changes proposed in subpart 3173 are ultimately adopted.

In addition to the changes proposed as part of the proposed rule for subpart 3173, the BLM proposes to revise paragraphs (a)(1) and (b)(1) to refer to ''any person'' and ''the person,'' respectively, rather than limiting the applicability of civil penalties to an operating rights owner or operator to be consistent with the statutory language found in Section 109(a) of FOGRMA, 30 U.S.C 1719(a). This proposed change would clarify that potential penalty liability exists for parties who contract with operating rights owners or operators to perform activities on Federal or Indian leases who violate applicable regulations, statutes, or lease terms in performing those activities. While the operating rights owner or operator is responsible (and liable for penalties) for violations committed by contractors, the contractors are also themselves subject to the requirements of the statutes, regulations, and lease terms. The BLM is proposing to revise the regulations to enable the agency to hold contractors directly responsible for violations they commit. Paragraph (g) also would be revised accordingly.

In addition, on April 21, 2015, the BLM published an Advance Notice of Proposed rulemaking (ANPR) (80 FR 22148) in which it requested public comment on whether the current regulatory caps on civil penalty assessments in 43 CFR 3163.2 (b), (d), (e), and (f) should be removed. As

[8] Under existing regulations, a ''major violation'' is one that ''causes or threatens immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income'' (Order 3, Sec. (II)(m)). A ''minor violation'' is defined as one that ''does not rise to the level of a 'major violation.' '' (*id.,* Sec. (II)(N)). As explained in the proposed rule to replace Order 3, the BLM is considering removing prescriptive regulatory definitions for ''Violation'' (major or minor) (80 FR 40,773, 40,787). Instead, the BLM would address these issues and the difference between a major and minor violation in an inspection and enforcement handbook, and, as appropriate, manuals or instructional memoranda (*id.*).

explained in the ANPR, the caps found in existing regulations are not required by statute and limit the total amount of the applicable penalties that can be assessed. Given that a modern oil and gas well can cost $5 million to $10 million dollars to drill, the BLM does not believe the existing caps provide an adequate deterrence for unlawful conduct, particularly drilling on Federal onshore leases without authorization and drilling into leased parcels in knowing and willful trespass. Similar concerns were expressed by the Department's OIG in a recent report, dated September 29, 2014—*Bureau of Land Management, Federal Onshore Oil & Gas Trespass and Drilling Without Approval* (No. CR–IS–BLM–0004–2014). In that report, the OIG expressed concern with the BLM's existing policies and procedures to detect trespass in or drilling without approval on Federal onshore oil and gas leases. Among other things, the OIG questioned the adequacy of the BLM's policies to deter such activities and recommended that the BLM pursue increased monetary fines.

The comment period on the ANPR closed on June 19, 2015. The BLM received approximately 82,000 comments. Of the 82,000 received, roughly 40 were unique, and the remainder were form comments. Of that 40, nine addressed the question of whether the caps imposed on civil penalties should be removed. Six of the nine comments that discussed the issue were in favor of changes to the existing caps; five asserted that existing caps do not provide adequate deterrence, while the sixth suggested that the caps be retained but increased to account for inflation. Three of the nine comments were generally opposed to any changes because of potential deterrence effects to development on public lands, but did not otherwise provide any detailed information.

After consideration of comments received and the concerns identified by the BLM and the OIG, the BLM is proposing as part of this rulemaking to remove those caps. Paragraphs (b), (d), (e), and (f) would be rewritten accordingly, while maintaining the statutory limits imposed on the amount that may be assessed on a daily basis (30 U.S.C. 1719(a)–(d)).[9] With the proposed removal of the caps, paragraph (j) was determined to be unnecessary given that its requirements were tiered off the expiration of the cap periods in the existing regulations.

Third, the BLM is also proposing to delete all of paragraph (g). The existing requirements of paragraph (g)(1) and (g)(2)(iii), which require initial proposed penalties to be at the maximum rate, are being removed because they are inconsistent with subsequent judicial and administrative decisions regarding the computation and setting of penalties. The BLM also determined that the requirements in paragraph (g)(1) and (g)(2)(iii) establishing caps on a per operating rights owner or operator per lease) would be removed as those provisions are inconsistent with the BLM's proposal to remove caps on penalties that are not required by statute. With respect to paragraphs (g)(2)(i) and (g)(2)(ii), the BLM is proposing to remove the additional notice procedure and corrective period for minor violations required under those paragraphs because it does not believe those provisions are necessary. The BLM's regulations governing oil and gas operations are clear, and provide more than adequate notice of what is required, making additional notification requirements unnecessary and administratively inefficient. As a result, all of paragraph (g) would be removed as part of this proposal. The removal of paragraph (g) means that existing paragraph (i) would be re-designated (g).

Finally, the BLM is proposing to move the substance of existing paragraph (k), which requires the revocation of a transporter's authority to remove crude oil produced from, or allocated to, any Federal or Indian lease if it fails to permit inspection for required documentation under 43 CFR 3162.7–1(c)), to paragraph (d) in order to streamline the regulations.

4. Paragraph (a) of § 3165.3 Notice, State Director review and hearing on the record, would be revised to refer to ''any person'' consistent with the revisions to Section 3163.1 and 3163.2.

5. Section 3164.1, Onshore Oil and Gas Orders, the table would be revised to remove the reference to Order 5 because this proposed rule would replace Order 5.

IV. Onshore Order Public Meetings, April 24–25, 2013

On April 24 and 25, 2013, the BLM held a series of public meetings to discuss draft proposed revisions to Orders 3 and 5, as well as Onshore Oil and Gas Order No. 4 (oil measurement). The meetings were webcast so that tribal members, industry, and the public across the country could participate and ask questions either in person or over the Internet. More than 200 people either logged in or were physically present for at least a portion of the meetings. Following the forum, the BLM opened a 36-day informal comment period, during which 13 comment letters were submitted. The following summarizes comments relating to Order 5 and gas measurement:

1. *Meter tube inspections.* The BLM received numerous comments regarding the cost and potential for lost revenue due to the draft proposed meter tube inspection frequencies: Once every 5 years for FMPs measuring more than 15 Mcf/day and less than or equal to 100 Mcf/day; once every 2 years for FMPs measuring more than 100 Mcf/day and less than or equal to 1,000 Mcf/day; and once every year for FMPs measuring more than 1,000 Mcf/day. The commenters stated that the burden is even higher for welded meter runs, where the meter tubes cannot be easily disassembled and removed for inspection, than for flanged meter runs. Because the meter must be shut in to perform the inspections, the commenters stated that there would be no royalty revenue generated during the time the inspection is conducted, which could take up to one day to complete and longer if problems are found. In addition, the potential for increased measurement uncertainty and bias is minimal and in most cases wouldn't make up for the lost revenue while performing the inspection. One commenter recommended that the BLM should only require routine meter tube inspections on FMPs measuring more than 1,000 Mcf/day. Another commenter suggested a threshold of 5,000 Mcf/day. Other commenters recommended the use of a borescope in lieu of a complete meter tube inspection. The BLM has analyzed the comments and generally agrees with the points made by the commenters. As a result, the draft proposal was changed to propose that routine detailed meter tube inspections (*i.e.,* disassembling and measuring the inside diameter) would only be required on high- and very-high volume FMPs and the frequency of these inspections was reduced from every 2 years to every 10 years for high-volume FMPs and from every year to every 5 years for very-high-volume FMPs. In addition, the BLM would now require a visual inspection using a borescope as suggested by one of the commenters to identify those meter tubes where there are noticeable issues that would signal the need for a detailed meter tube inspection. A complete discussion of the proposed changes

[9] The statutory limit on daily penalties associated with paragraphs (a) and (d) of 3163.2 appears in 30 U.S.C. 1719(a); the limit associated with paragraph (b) appears in 30 U.S.C. 1719(b); the limit associated with paragraph (e) appears in 30 U.S.C. 1719(c); and the limit associated with paragraph (f) appears in 30 U.S.C. 1719(d).

appears in the earlier discussion of meter tube inspections under proposed § 3175.80(h) and (i).

2. *Heating value reporting basis.* The BLM received numerous comments objecting to the draft proposed requirement to report the heating value of gas removed from Federal or Indian leases on a ''dry'' basis. Heating value reported on a dry basis assumes that there is no water vapor in the gas. The commenters suggested that the BLM accept heating value reported on an ''as delivered'' basis instead, which assumes that the gas is saturated with water vapor at metered pressure and temperature as addressed in the GPA publication 2172–09. The rationale given by the commenters is that all gas contains some degree of water vapor and forcing operators to report on a dry basis will result in overpayment of royalty.

Because the water vapor content in a gas sample is not easily measured, industry has been using various assumptions of water vapor content for decades. One commonly used assumption is that the gas is saturated with water vapor at 14.73 psia and 60°F. This assumption has no factual basis and typically results in a reduction of heating value (and royalty) due to water vapor that cannot physically exist at the meter. The publication of GPA 2172–09 was the first industry standard addressing the ''as delivered'' basis, which assumes the gas is saturated with water vapor at metered pressure and temperature. The ''as delivered'' basis, however, is still an assumption that lowers the heating value of the gas and the royalty that is owed. The BLM believes that in the absence of data showing otherwise, heating value should be reported based on the assumption that the gas contains no water vapor. To be marketable, gas must be dehydrated to pipeline specifications, which are generally very close to no water vapor. Moreover, under the longstanding ''marketable condition'' rule, the lessee must perform that dehydration without deducting the costs in determining royalty value. 30 CFR 1206.152(i); 1206.153(i); and 1206.174(h); *Devon Energy Corp.* v. *Kempthorne,* 558 F.3d 1030 (D.C. Cir. 2008). The BLM does not believe that the public, Indian tribes, or Indian allottees should suffer a reduced royalty based on an assumption that is unsupported by data.

The BLM will consider allowing heating value to be reported on an as-delivered basis (or some adaptation of it) if we receive sufficient data showing that assuming water vapor saturation, or a certain level of water vapor, under metered pressure and temperature is reasonable and supported by field data. See discussion of proposed § 3175.120(a)(3) for further explanation of heating value reporting basis.

3. *Extended analysis.* The BLM received numerous comments objecting to the draft proposed requirement for extended analysis of heavier hydrocarbons (through nonane +) if the hexane + concentration was greater than 0.25 mole percent. Some commenters objected to an extended analysis under any circumstance while other commenters suggested that the requirement be applied only to high-volume and very-high-volume FMPs. The reasoning given by the commenters is that extended analysis adds significant cost to performing a gas analysis and results in very little change in heating value. One commenter referenced a study which concluded that the difference between a hexane + analysis and an extended analysis resulted in less than a 2 Btu/scf difference.

Based on these comments, the BLM has changed the extended analysis requirement in the proposed rule to apply only to high-volume and very-high-volume FMPs. The BLM's analysis shows that using an assumed component distribution for hexane+ (60 percent hexane, 30 percent heptane, and 10 percent octane) results in additional uncertainty as the hexane+ concentration increases, but does not result in statistically significant bias. Because the heating value certainty standards proposed in § 3175.30(b) do not apply to marginal-volume and low-volume FMPs, marginal- and low-volume FMPs should not be subject to the proposed extended analysis requirement. The BLM may consider further modifications to the proposed extended analysis requirement if commenters submit sufficient extended analysis data that show there is little difference in heating value between the hexane+ analysis and the extended analysis.

4. *Dynamic sampling frequency.* The BLM received numerous comments on the draft proposed dynamic gas sampling frequency. The majority of the comments said it would be impractical to have the sampling frequency for high-volume and very-high-volume FMPs change after every sample to meet the heating value certainty requirements given in proposed § 3175.115. Other comments said the draft proposed heating value certainty levels would be more restrictive than the heating value uncertainties given in publications such as GPA 2166. One comment concluded that the only way to meet the draft proposed certainty level for very-high-volume FMPs would be to install a composite sampling system which would be costly and may not work properly on wellhead applications.

Based on these comments, the BLM is proposing a modified version of the dynamic sampling frequency discussed at the public meetings. Following the suggestion of one of the commenters, this proposed rule would establish an initial sampling frequency and then allow for an adjustment of that frequency based on historic heating-value variability. Rather than having sampling frequencies calculated to the nearest day, the calculated sampling frequency would be rounded down to the nearest of one of seven set frequencies: Weekly, every 2 weeks, monthly, every 2 months, every 3 months, every 6 months, and annually. The frequency would not change until a new calculation resulted in either an increase or decrease of the frequency. In addition, the BLM raised the uncertainty standards in proposed § 3175.30(b). We believe the modifications will simplify implementation while still meeting the objective of achieving a set level of uncertainty. Please see the discussion of proposed § 3175.115 for further explanation of gas sampling frequency.

5. *Grandfathering existing equipment.* Several comments suggested that the BLM ''grandfather'' existing equipment from the requirements of the draft proposed rule. The BLM did not make any changes to the proposed rule based on these comments.

Grandfathering is generally unworkable for two reasons. First, grandfathering would result in two tiers of equipment—older equipment that must meet the standards of a rule that is no longer in effect and newer equipment which would have to meet the standards of the new rule. This would not only require the BLM to maintain, inspect against, and enforce two sets of regulations (one of which no longer applies to equipment coming into service), but also to track which FMPs have been grandfathered and which are subject to the new regulations.

Second, the reason for promulgating new regulations is that the BLM believes new regulations could better ensure accurate and verifiable measurement of oil and gas removed or sold from Federal and Indian leases. In lieu of grandfathering, the BLM has proposed grace periods for bringing existing facilities into compliance with the proposed standards (see proposed § 3175.60). These grace periods are tiered to the volume measured by the FMP, giving more time to bring lower-volume FMPs into compliance. The proposed rule would allow meter tubes at low volume FMPs to meet the eccentricity requirements required in AGA Report No. 3 (1985). Please see previous discussion of proposed § 3175.80(f) for further explanation of this proposed requirement.

6. *Transducer and software type testing.* The BLM received several comments expressing concern over the draft proposed requirement for type testing computer software and transducers that are already in use. The comments state that existing equipment met or exceeded API or GPA standards at the time of installation and, therefore, should be exempt from any new type-testing requirement. One commenter suggested that equipment used on marginal-volume and low-volume FMPs should be exempt from the type testing requirement.

The BLM is unaware of any API or GPA standards relating to transducer performance; that is the reason we are proposing the transducer type-testing protocol in this rule (and why API is developing a new standard to address type testing). The proposed type-testing requirement for transducers would not prescribe a standard for transducers. The type testing requirement would quantify the uncertainty of the device tested under specified test conditions. The results of the test would be incorporated into the calculation of overall measurement uncertainty. The transducer performance determined under the proposed protocol could, however, be sufficiently different from the manufacturer's specifications as to result in unacceptable overall meter uncertainty. The BLM does not believe that this will result in a significant cost burden to operators, and specifically requests comment on costs to comply with this proposed requirement.

The BLM agrees with the comments regarding marginal-volume and low-volume FMPs and has exempted both categories of FMPs in the proposed rule. Because transducer testing defines the uncertainty of the devices and marginal volume and low volume FMPs are not subject to uncertainty requirements, we did not feel that characterizing the performance of transducers used at these FMPs is necessary. See the discussion of proposed §§ 3175.43 and 3175.130 for further explanation of this proposed requirement.

However, the BLM did not exempt low-volume FMPs from the flow computer software testing. Errors in flow-computer software can cause biases in measurement. Because low-volume FMPs would have to meet the performance requirements for bias in proposed § 3175.140, flow-computer software testing requirements would apply.

7. *Purchasers and transporters.* The BLM received one comment objecting to the draft proposed requirement that would allow the BLM to take enforcement actions against purchasers and transporters for not maintaining and submitting records. The requirement for purchasers and transporters to maintain records is imposed by Section 103(a) of FOGRMA, 30 U.S.C. 1713(a). The BLM believes that enforcement of that requirement is appropriate.

8. *Ultrasonic meters.* The BLM received one comment suggesting that the proposed rule include ultrasonic meters. Although the BLM does not currently accept linear meters, including ultrasonic meters, for gas measurement, a linear meter approval section was added to the proposed rule (proposed § 3175.48) based on this comment. However, the approval would be on a case-by-case basis as determined by the PMT.

9. *CO_2 operations.* The BLM received one comment about the necessity of gas sampling for CO_2 operations because CO_2 has no heating value. While the BLM agrees that heating value would have no bearing on the royalty paid for CO_2, gas sampling would still be required to determine the gas gravity which is used in volume determination. The BLM did not make any changes to the proposed rule based on this comment. The BLM can address specific requirements relating to CO_2 operations on a case-by-case basis through the variance process.

10. *Volume thresholds.* The BLM received one comment objecting to lowering the low-volume threshold from 100 Mcf/day in Order 5 to 15 Mcf/day in the draft proposed rule. The proposed rule does not lower the threshold for low-volume FMPs. It would create a new category of marginal-volume FMPs. Order 5 makes only three exemptions from its requirements for meters measuring less than 100 Mcf/day: (1) The operator does not have to comply with Beta ratio limits; (2) The operator does not have to operate the differential pen of a chart recorder in the outer two-thirds of the chart for a majority of the flowing period; and (3) The operator does not need a continuous temperature recorder (the threshold for continuous temperature recorders is 200 Mcf/day). The proposed rule would generally maintain these exemptions for low-volume FMPs. The tier for marginal-volume FMPs was added to give additional relief from other requirements for those FMPs where production is on the edge of economic viability.

11. *Certainty levels for very-high-volume FMPs.* Several commenters objected to the proposed ±1.5 percent uncertainty requirement for very-high-volume FMPs, stating that this could only be achieved with near-ideal flowing conditions. These conditions do not typically exist at the on-lease measurement points typical to the BLM. After further consideration, the BLM agrees that an uncertainty of ±1.5 percent may be difficult to achieve, even for very-high-volume FMPs. As a result, the BLM increased the proposed uncertainty requirement for very-high-volume FMPs to ±2 percent.

V. Procedural Matters

Executive Order 12866, Regulatory Planning and Review

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) will review all significant rules. The OIRA has determined that this rule is significant because it would raise novel legal or policy issues.

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system so that it promotes predictability, reduces uncertainty, and uses 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. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this rulemaking consistent with these requirements.

Regulatory Flexibility Act

The BLM certifies that this proposed rule would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). The Small Business Administration (SBA) has developed size standards to define small entities, and those size standards can be found at 13 CFR 121.201. Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA regulations as a business concern, including an individual proprietorship, partnership, limited liability company, or corporation, with fewer than 500 employees.

Of the 6,628 domestic firms involved in onshore oil and gas extraction, 99 percent (or 6,561) had fewer than 500 employees. Based on this national data, the preponderance of firms involved in developing oil and gas resources are small entities as defined by the SBA. As such, it appears a substantial number of small entities would be potentially affected by the proposed rule. Using the best available data, the BLM estimates there are approximately 3,700 lessees and operators conducting gas operations on Federal and Indian lands that could be affected by the proposed rule.

In addition to determining whether a substantial number of small entities are likely to be affected by this rule, the BLM must also determine whether the rule is anticipated to have a significant economic impact on those small entities. On an ongoing basis, we estimate the proposed changes would increase the regulated community's annual costs by about $46 million, or an average of about $13,000 per entity per year (not including anticipated increased royalty on increased revenue discussed earlier). In addition, there would be one-time costs associated with implementing the proposed changes of as much as $33 million, or an average of approximately $8,900 per entity affected by the proposed rule, phased in over a 3-year period. For further information on these costs estimates, please see the Economic and Threshold Analysis prepared for this proposed rule. The BLM is specifically seeking comment on that analysis and the assumptions used to generate these estimates.

Recognizing that the SBA definition for a small business in the relevant categories is one with fewer than 500 employees, which represents a wide range of possible oil and gas producers, the BLM, as part of an Economic and Threshold Analysis conducted for this rulemaking, looked at income data for three different small-sized entities that currently hold Federal oil and gas leases that were issued in competitive sales. Using annual reports that these companies filed with the U.S. Securities and Exchange Commission for 2012, 2013, and 2014, the BLM concluded that the one-time costs and the annual ongoing costs would result in a reduction in the profit margins of these entities ranging from 0.0005 percent to 0.5742 percent, with an average reduction of 0.0362 percent. Copies of the analysis can be obtained from the contact person listed above (see **FOR FURTHER INFORMATION CONTACT**) and at *www.regulations.gov*, search for 1004–AE17.

All of the proposed provisions would apply to entities regardless of size. However, entities with the greatest activity (*e.g.,* numerous FMPs) would likely experience the greatest increase in compliance costs.

Based on the available information, we conclude that the proposed rule would not have a significant impact on a substantial number of small entities. Therefore, a final Regulatory Flexibility Analysis is not required, and a Small Entity Compliance Guide is not required.

Small Business Regulatory Enforcement Fairness Act

This proposed rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule would not have an annual effect on the economy of $100 million or more. As explained under the preamble discussion concerning Executive Order 12866, Regulatory Planning and Review, the proposed rule would increase, by about $46 million annually, the cost associated with the development and production of gas resources under Federal and Indian oil and gas leases. There would also be a one-time cost estimated to be $33 million.

This rulemaking proposes to replace Order 5 to ensure that gas produced from Federal and Indian oil and gas leases is more accurately accounted for. As described under the section concerning Executive Order 12866, Regulatory Planning and Review, the average estimated annual increased cost to each entity that produces gas from all Federal and Indian leases for implementing these changes would be about $13,000 per year, and a one-time average cost of about $8,900 per entity, phased in over a 3-year period.

This proposed rule:

- Would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, tribal, or 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.

Unfunded Mandates Reform Act

Under the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*), we find that:

- This proposed rule would not ''significantly or uniquely'' affect small governments. A Small Government Agency Plan is unnecessary.
- This proposed rule would not include any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or greater in any single year.

The proposed rule is not a ''significant regulatory action'' under the Unfunded Mandates Reform Act. The changes proposed in this rule would not impose any requirements on any State or local governmental entity.

Executive Order 12630, Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings)

The proposed rule would not have significant takings implications as defined under Executive Order 12630. A takings implication assessment is not required. This proposed rule would revise the minimum standards for accurate measurement and proper reporting of gas produced from Federal and Indian leases, unit PAs, and CAs, by providing an improved system for production accountability by operators and lessees. Gas production from Federal and Indian leases is subject to lease terms that expressly require that lease activities be conducted in compliance with applicable Federal laws and regulations. The implementation of this proposed rule would not impose requirements or limitations on private property use or require dedications or exactions from owners of private property, and as such, the proposed rule is not a governmental action capable of interfering with constitutionally protected property rights. Therefore, the proposed rule would not cause a taking of private property or require further discussion of takings implications under this Executive Order.

Executive Order 13132, Federalism

Under Executive Order 13132, the BLM finds that the proposed rule would not have significant Federalism implications. A Federalism assessment is not required. This proposed rule would not change the role of or responsibilities among Federal, State, and local governmental entities. It does not relate to the structure and role of the States and would not have direct or substantive effects on States.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Under Executive order 13175, the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951), and 512

Departmental Manual 2, the BLM evaluated possible effects of the proposed rule on federally recognized Indian tribes. The BLM approves proposed operations on all Indian onshore oil and gas leases (other than those of the Osage Tribe). Therefore, the proposed rule has the potential to affect Indian tribes. In conformance with the Secretary's policy on tribal consultation, the BLM held three tribal consultation meetings to which more than 175 tribal entities were invited. The consultations were held in:

- Tulsa, Oklahoma on July 11, 2011;
- Farmington, New Mexico on July 13, 2011; and
- Billings, Montana on August 24, 2011.

In addition, the BLM hosted a tribal workshop and webcast on April 24, 2013. The purpose of these meetings was to solicit initial feedback and preliminary comments from the tribes. Comments from the tribes will continue to be accepted and consultation will continue as this rulemaking proceeds. To date, the tribes have expressed concerns about the subordination of tribal laws, rules, and regulations to the proposed rule; tribes' representation on the DOI GOMT; and the BLM's Inspection and Enforcement program's ability to enforce the terms of this proposed rule. While the BLM will continue to address these concerns, none of the concerns expressed relate to or affect the substance of this proposed rule.

Executive Order 12988, Civil Justice Reform

Under Executive Order 12988, we have determined that the proposed rule would not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the Order. We have reviewed the proposed rule to eliminate drafting errors and ambiguity. It has been written to provide clear legal standards for affected conduct rather than general standards, and promote simplification and burden reduction.

Executive Order 13352, Facilitation of Cooperative Conservation

Under Executive Order 13352, the BLM has determined that this proposed rule would not impede facilitating cooperative conservation and would take appropriate account of and consider the interests of persons with ownership or other legally recognized interests in land or other natural resources. This rulemaking process will involve Federal, State, local and tribal governments, private for-profit and nonprofit institutions, other nongovernmental entities and individuals in the decision-making via the public comment process for the rule. The process will provide that the programs, projects, and activities are consistent with protecting public health and safety.

Paperwork Reduction Act

I. Overview

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501–3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a "collection of information," unless it displays a currently valid OMB control number. This proposed rule contains information collection requirements that are subject to review by OMB under the PRA. Collections of information include any request or requirement that persons obtain, maintain, retain, or report information to an agency, or disclose information to a third party or to the public (44 U.S.C. 3502(3) and 5 CFR 1320.3(c)). After promulgating a final rule and receiving approval from the OMB (in the form of a new control number), the BLM intends to ask OMB to combine the activities authorized by the new control number with existing control number 1004–0137, Onshore Oil and Gas Operations (expiration date January 31, 2018).

The information collection activities in this proposed rule are described below along with estimates of the annual burdens. Included in the burden estimates are the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing each component of the proposed information collection requirements.

The information collection request for this proposed rule has been submitted to OMB for review under 44 U.S.C. 3507(d). A copy of the request can be obtained from the BLM by electronic mail request to Jennifer Spencer at *j35spenc@blm.gov* or by telephone request to 202–912–7146. You may also review the information collection request online at *http://www.reginfo.gov/public/do/PRAMain*.

The BLM requests comments on the following subjects:

1. Whether the collection of information is necessary for the proper functioning of the BLM, including whether the information will have practical utility;
2. The accuracy of the BLM's estimate of the burden of collecting the information, including the validity of the methodology and assumptions used;
3. The quality, utility, and clarity of the information to be collected; and
4. How to minimize the information collection burden on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other forms of information technology.

If you want to comment on the information collection requirements of this proposed rule, please send your comments directly to OMB, with a copy to the BLM, as directed in the **DATES** and **ADDRESSES** sections of this preamble. Please identify your comments with "OMB Control Number 1004–XXXX." OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by November 12, 2015.

II. Summary of Proposed Information Collection Requirements

Title: Measurement of Gas.

OMB Control Number: Not assigned. This is a new collection of information.

Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, operators, purchasers, transporters, and any other person directly involved in producing, transporting, purchasing, or selling, including measuring, oil or gas through the point of royalty measurement or the point of first sale.

Respondents' Obligation: Required to obtain or retain a benefit.

Frequency of Collection: On occasion, with the following exception:

Proposed § 3175.120 would require the submission of gas analysis reports to the BLM within 5 days of the following due dates for the sample as specified in proposed § 3175.115:

(a) Gas samples at low-volume FMPs would be required at least every 6 months;

(b) Gas samples at marginal-volume FMPs would be required at least annually; and

(c) Spot samples at high- and very-high-volume FMPs would be required at least every 3 months and every month, respectively, unless the BLM determines that more frequent analysis is required under § 3175.115(c).

Abstract: This proposed rule would update the BLM's regulations pertaining to gas measurement, taking into account changes in the gas industry's measurement technologies and standards. The information collection activities in this proposed rule would assist the BLM in ensuring the accurate measurement and proper reporting of all gas removed or sold from Federal and Indian leases, units, unit participating areas, and areas subject to communitization agreements, by providing a system for production accountability by operators, lessees, purchasers, and transporters.

Estimated Total Annual Burden Hours: The proposed rule would result in an estimated 273,208 responses and 470,716 burden hours annually.

Estimated Total Non-Hour Cost: In order to comply with the proposed rule, operators would be required to install or modify equipment at an estimated cost of $32 million.

III. Proposed Information Collection Requirements

A. Documentation To Be Reviewed by the Production Measurement Team (PMT)

Some of the information collection activities in the proposed rule would involve review of documentation by the PMT, made up of measurement experts from the BLM. The PMT would act as a central BLM advisory body for reviewing and approving devices and software not specifically addressed in the currently proposed regulations. The documentation submitted to the PMT would assist the BLM in ensuring that the hardware and software used in gas measurement are in compliance with performance standards proposed in this rule.

1. Flow Conditioner Testing Report

Proposed § 3175.46 would provide for listing of approved makes and models of isolating flow conditioners at *www.blm.gov*, and would provide for a procedure for seeking approval of additional makes and models. That procedure would involve preparing a report that would have to show the results of testing required by proposed § 3175.46. Upon review of the report, the PMT would make a recommendation to the BLM to approve use of the device, disapprove use of the device, or approve it with conditions for its use. The BLM would add any approved device to a list of approved flow conditioners at *www.blm.gov*.

2. Differential Primary Devices Other Than Flange-Tapped Orifice Plates

Proposed § 3175.47 would authorize operators to seek approval to use a particular make and model of a differential primary device (other than flange-tapped orifice plates and those listed at *www.blm.gov*) by collecting all test data required under API 22.2 (incorporated by reference, see § 3175.31) and reporting it to the PMT. The PMT would review the test data to ensure that the primary device meets the relevant requirements and make a recommendation to the BLM to approve use of the device, disapprove use of the device, or approve its use with conditions.

3. Linear Measurement Device Testing Report

Proposed § 3175.48 would require submission of a report showing the results of each test required by the PMT. This report would be reviewed by the PMT and would be a pre-requisite for BLM approval of a linear type of meter in lieu of an approved type of differential meter. This requirement would assist the BLM in ensuring that meters used in gas measurement are in compliance with performance standards.'' The PMT would review the data to determine whether the meter meets the requirements of § 3175.30, and make a recommendation to the BLM, which would approve use of the device, disapprove use of the device, or approve its use with conditions.

4. Transducer Testing Report

Proposed § 3175.43 would require submission of a report showing the results of each test required by proposed §§ 3175.131 through 3175.135, including all data points recorded. This report would be reviewed by the PMT, and would be a pre-requisite for BLM approval of a particular make and model of transducer for use in an electronic gas metering (EGM) system. This requirement would assist the BLM in ensuring that transducers used in gas measurement are in compliance with performance standards.

5. Flow-Computer and Software Version Testing Report

Proposed § 3175.44 would require submission of a report showing the results of each test required by proposed §§ 3175.141 through 3175.143, including all data points recorded. This report would be reviewed by the PMT, and would be a pre-requisite for BLM approval of software for use in an electronic gas measurement (EGM) system. This requirement would assist the BLM in ensuring that software used in gas measurement is in compliance with performance standards.

B. Other Proposed Information Collection Activities

1. Orifice Plate Inspection Report

Proposed § 3175.80(e) would require operators to retain, and submit to the BLM upon request, usually during a production audit, documentation for every orifice plate inspection and include that documentation as part of the verification report required at proposed § 3175.92(d) (where the operator uses mechanical recorders) or proposed § 3175.102(e) (where the operator uses EGM systems). The documentation would be required to include:

- The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
- Plate orientation (bevel upstream or downstream);
- Measured orifice bore diameter;
- Confirmation that the plate condition complies with the applicable API standard;
- The presence of oil, grease, paraffin, scale, or other contaminants found on the plate;
- Time and date of inspection; and
- Whether or not the plate was replaced.

2. Meter-Tube Inspection Report

Proposed § 3175.80(j) would require operators to retain, and submit to the BLM upon request, usually during a production audit, documentation demonstrating that the meter tube complies with applicable API standards and showing completion of all required measurements. Upon request, the operator would also be required to provide the information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record).

3. Verification for Mechanical Recorders

Proposed 43 CFR 3175.92(d) would require operators to retain, and submit to the BLM upon request, usually during a production audit, documentation of each verification for mechanical recorders. This documentation would be required to include:

- The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
- The time and date of the verification and the prior verification date;
- Primary-device data (meter-tube inside diameter and differential-device size and beta or area ratio);
- The type and location of taps (flange or pipe, upstream or downstream static tap);

• Atmospheric pressure used to offset the static-pressure pen, if applicable;
• Mechanical recorder data (make, model, and differential pressure, static pressure, and temperature element ranges);
• The normal operating points for differential pressure, static pressure, and flowing temperature;
• Verification points (as-found and applied) for each element;
• Verification points (as-left and applied) for each element, if a calibration was performed;
• Names, contact information, and affiliations of the person performing the verification and any witness, if applicable; and
• Remarks, if any.

4. Retention of Test Equipment Recertification

Proposed § 3175.92(g) would require operators to certify test equipment used to verify or calibrate the static pressure, differential pressure, and temperature elements/transducers at an FMP at least every 2 years. Documentation of the recertification would be required to be on-site during all verifications and would be required to show:
• Test equipment serial number, make, and model;
• The date on which the recertification took place;
• The test equipment measurement range; and
• The uncertainty determined or verified as part of the recertification.

5. Mechanical Recorder Integration Statement

Proposed § 3175.93 would require operators to retain, and submit to the BLM upon request, usually during a production audit, integration statements containing the following information:
• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
• The name of the company performing the integration;
• The month and year for which the integration statement applies;
• Meter-tube inside diameter (inches);
• Information of the primary device;
• Relative density (specific gravity);
• CO_2 content (mole percent);
• N_2 content (mole percent);
• Heating value calculated under § 3175.125 (Btu/standard cubic feet);
• Atmospheric pressure or elevation at the FMP;
• Pressure base;
• Temperature base;
• Static pressure tap location (upstream or downstream);
• Chart rotation (hours or days);
• Differential pressure bellows range (inches of water);
• Static pressure element range (psi); and
• For each chart or day integrated, the time and date on and time and date off, average differential pressure (inches of water), average static pressure, static pressure units of measure (psia or psig), average temperature (° F), integrator counts or extension, hours of flow, and volume (Mcf).

6. Routine Verification for EGMs

Proposed § 3175.102(e)(1) would require operators to retain, and submit to the BLM upon request, usually during a production audit, documentation of each verification of an EGM . This documentation would be required to include:
• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
• The time and date of the verification and the last verification date;
• Primary device data (meter-tube inside diameter and differential-device size, beta or area ratio);
• The type and location of taps (flange or pipe, upstream or downstream static tap);
• The flow computer make and model;
• The make and model number for each transducer, for component-type EGM systems;
• Transducer data (make, model, differential, static, temperature URL, and upper calibrated limit);
• The normal operating points for differential pressure, static pressure, and flowing temperature;
• Atmospheric pressure;
• Verification points (as-found and applied) for each transducer;
• Verification points (as-left and applied) for each transducer, if calibration was performed;
• The differential device inspection date and condition (*e.g.,* clean, sharp edge, or surface condition);
• Verification of equipment make, model, range, accuracy, and last certification date;
• The name, contact information, and affiliation of the person performing the verification and any witness, if applicable; and
• Remarks, if any.

7. Redundancy Verification Check for EGMs

Proposed 43 CFR 3175.102(e)(2) would allow redundancy verification in lieu of routine verification. If an operator opts to use redundancy verification, the proposed rule would establish standards for the information that must be retained and submitted to the BLM upon request, usually during a production audit. The following would be the required information for redundancy verification checks:
• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
• The month and year for which the redundancy check applies;
• The makes, models, upper range limits, and upper calibrated limits of the primary set of transducers;
• The makes, models, upper range limits, and upper calibrated limits of the check set of transducers;
• The information required in API 21.1, Annex I, which includes comparisons of volume, energy, differential pressure, static pressure, and temperature both in tabular form (average values) and graphical form (instantaneous values);
• The tolerance for differential pressure, static pressure, and temperature as calculated under proposed 43 CFR 3175.102(d)(2) of this section; and
• Whether or not each transducer required verification under paragraph (c) of this section.

8. Quantity Transaction Record

Proposed § 3175.104(a) would require operators to retain the original, unaltered, unprocessed, and unedited daily and hourly quantity transaction record (QTR) and submit them to the BLM upon request, usually during a production audit. The proposed rule would require the QTR to contain the information identified in API 21.1.5.2 (date and time identifier, quantity [volume, mass and/or energy], flow time, integral value/average extension, differential pressure average, static pressure average, temperature average, and relative density, energy content, composition, and/or density averages must be included if they are live inputs), with the following additions and clarifications:
• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
• The volume, flow time, integral value or average extension, and the average differential pressure, static pressure, and temperature as calculated in proposed § 3175.103(c), reported to at least five significant digits; and
• A statement of whether the operator has submitted the integral value or average extension.

9. Configuration Log

Proposed 43 CFR 3175.104(b) would require operators to retain, and submit to the BLM upon request, usually during a production audit, the original, unaltered, unprocessed, and unedited configuration log. The proposed rule would require the configuration log to contain the information under API 21.1.5.4 (meter identifier, date and time collected, contract hour, atmospheric pressure for sites with gauge pressure transmitters, pressure base, temperature base, timestamp definition, calibrated or user defined span for differential pressure, no flow cutoff, calibrated or user defined span for static pressure, static pressure type [absolute or gauge], calibrated or user defined operating range for temperature or fixed temperature if not live, gas composition [if not live], relative density [if not live], compressibility [if not live], energy content [if not live], meter tube reference inside diameter, meter tube material, meter tube reference temperature, meter tube static pressure tap location [upstream/downstream], orifice plate reference bore size, orifice plate material, orifice plate reference temperature. discharge coefficient calculation method/reference, gas expansion factor method/reference, compressibility calculation method/reference, quantity calculation period, sampling rate, variables included in the integral value, base compressibility of air, absolute viscosity [*cP*], ratio of specific heats, meter elevation or contract value of atmospheric pressure, other factors used to determine flow rate, alarm set points [differential pressure low, differential pressure high, static pressure low, static pressure high, flowing temperature low, flowing temperature high.] For primary devices other than an orifice plate, the primary device type, material, reference temperature, size, Beta/area ratio, discharge coefficient, and factors necessary to calculate discharge coefficient) including, with the following additions and clarifications:

• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);

• Software/firmware identifiers that comply with applicable API standards;

• The fixed temperature, if not live (° F);

• The static-pressure tap location (upstream or downstream); and

• The flow computer snapshot report in API 21.1.5.4.2 and API 21.1, Annex G.

10. Event Log

Proposed § 3175.104(c) would require operators to retain the original, unaltered, unprocessed, and unedited event log and submit it to the BLM upon request, usually during a production audit. The event log must comply with API 21.1.5.5 (the chronological listing of the date and time of any change to a constant flow parameter that can affect the quantity transaction record, along with the old and new value), with the following additions and clarifications:

• The event log must record all power outages (including the length of the outage) that inhibit the meter's ability to collect and store new data; and

• The event log must have sufficient capacity and must be retrieved and stored at intervals frequent enough to maintain a continuous record of events as required under proposed § 3170.7, or the life of the FMP, whichever is shorter.

11. Gas Chromatograph Verification

Proposed 3175.117(c) and (d) would require operators to retain the manufacturer's specifications and installation and operational recommendations for on-line gas chromatographs, and the results of all verifications of on-line gas chromatographs and submit the information to the BLM upon request, usually during a production audit. Proposed § 3175.118(i) would require the gas chromatograph verification to contain:

• The components analyzed;
• The response factor for each component;
• The peak area for each component;
• The mole percent of each component as determined by the GC;
• The mole percent of each component in the gas used for verification;
• The difference between the mole percents determined in paragraphs (i)(4) and (i)(5) of this section, expressed in relative percent;
• Documentation that the gas used for verification meets the requirements of GPA 2198–03 (incorporated by reference, see § 3175.31), including a unique identification number of the calibration gas used and the name of the supplier of the calibration gas;
• The time and date the verification was performed; and
• The name and affiliation of the person performing the verification.

12. Gas Analysis Report

Operators would be required to submit gas analysis reports to the BLM within 5 days of the due date for the sample as specified in proposed § 3175.115. Submission would be done electronically into a BLM database. Paragraph (a) would provide that, unless otherwise required under paragraph (b), spot samples for all FMPs would be required to be taken and analyzed at the frequency specified at Table 4 of proposed § 3175.110.

Paragraph (b) would provide that the BLM could change the required sampling frequency for high-volume and very-high-volume FMPs if the BLM determines that the sampling frequency required in Table 4 is not sufficient to achieve the heating value certainty levels required in proposed § 3175.30(b). Table 5 at paragraph (c) would limit the amount of time that would be allowed between any two samples.

Proposed 3175.120 would require gas analysis reports to contain the following information:

• The information required in proposed § 3170.7(g) (*i.e.,* the FMP number and the name of the company that created the record);
• The date and time that the sample for spot samples was taken or, for composite samples, the date the cylinder was installed and the date the cylinder was removed;
• The date and time of the analysis;
• For spot samples, the effective date, if other than the date of sampling;
• For composite samples, the effective start and end date;
• The name of the laboratory where the analysis was performed;
• The device used for analysis (*i.e.,* GC, calorimeter, or mass spectrometer);
• The make and model of analyzer;
• The date of last calibration or verification of the analyzer;
• The flowing temperature at the time of sampling;
• The flowing pressure at the time of sampling, including units of measure (psia or psig);
• The flow rate at the time of the sampling;
• The ambient air temperature at the time the sample was taken;
• Whether or not heat trace or any other method of heating was used;
• The type of sample (*i.e.,* spot-cylinder, spot-portable GC, composite);
• The sampling method if spot-cylinder (*e.g.,* fill and empty, helium pop);
• A list of the components of the gas tested;
• The un-normalized mole percentages of the components tested, including a summation of those mole percents;
• The normalized mole percent of each component tested, including a summation of those mole percents;

- The ideal heating value (Btu/scf);
- The real heating value (Btu/scf), dry basis;
- The pressure base and temperature base;
- The relative density; and
- The name of the company obtaining the gas sample.

Components that are listed on the analysis report, but not tested, would be required to be annotated as such.

13. Quantity Transaction Report Edits

Proposed § 3175.126(c)(2) would require operators to identify and verifiably justify all values on daily and hourly QTRs that have been changed or edited as a result of measurement errors stemming from an equipment malfunction causing discrepancies in the calculated volume or heating value of the gas. This documentation would be required to be retained under proposed § 3170.7 and submitted to the BLM upon request, usually during a production audit.

IV. Burden Estimates

The following table itemizes the annual estimated information collection burdens of this proposed rule:

Type of response A	Number of responses B	Hours per response C	Total hours D
Flow Conditioner Testing Report (43 CFR 3175.46)	1	400	400
Differential Primary Devices Other than Flange-Tapped Orifice Plates (43 CFR 3175.47)	1	400	400
Linear Measurement Device Testing Report (43 CFR 3175.48)	1	200	200
Verification for Mechanical Recorders (43 CFR 3175.92(d)) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Mechanical Recorder Integration Statement (43 CFR 3175.93) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Routine Verification for EGMs (43 CFR 3175.102(e)) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Event Log (43 CFR 3175.104(c)) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Transducer Testing Report (43 CFR 3175.134)	20	395	7,900
Flow-Computer and Software Version Testing Report (43 CFR 3175.144)	20	395	7.900
Orifice Plate Inspection Report (43 CFR 3175.80(e)) *Recordkeeping requirement*	28,436	1	28,436
Meter-Tube Inspection Report (43 CFR 3175.80(j)) *Recordkeeping requirement*	16,160	4.35	70,296
Retention of Test Equipment Recertification on-site (43 CFR 3175.92(g))	2,000	0.1	200
Redundancy Verification Check for EGMs (43 CFR 3175.102(e)(2)) *Recordkeeping requirement*	1,000	0.5	500
Quantity Transaction Record (43 CFR 3175.104(a)) *Recordkeeping requirement*	3,185	3	9,555
Configuration Log (43 CFR 3175.104(b)) *Recordkeeping requirement*	3,185	3	9,555
Gas Chromatograph Verification (43 CFR 3175.117(c) and (d)) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Gas Analysis Report (43 CFR 3175.120)	219,199	1.53	335,374
Quantity Transaction Record Edits (43 CFR 3175.126(c)(2)) *Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)*	0	0	0
Totals	273,208		470,716

The information collection activities that appear in the above table with the notation, ''Usual and customary, within the meaning of 5 CFR 1320.3(b)(2)'' are standard industry practices and will not result in collection burdens for industry in addition to those incurred in the ordinary course of their business. For reasons documented in the descriptions of the proposed information collection requirements, the BLM believes the burdens of these proposals are exempt from the PRA in accordance with 5 CFR 1320.3(b)(2). That is why no burdens are indicated for those activities.

The information collection activities that appear in the above table with the notation, ''Recordkeeping requirement'' are included in this PRA analysis because this proposed rule would require respondents to collect and retain certain information. However, any requirement to submit the information to the BLM (usually during a production audit) would be in accordance with the BLM's proposed rule on site security, which was published on July 13, 2015 (80 FR 40768). OMB has assigned control number 1004–0207 to that proposed rule, but has not yet authorized the BLM to begin collecting information under that control number.

National Environmental Policy Act

The BLM has prepared a draft environmental assessment (EA) that concludes that this proposed rule would not have a significant impact on the quality of the environment under NEPA, 42 U.S.C. 4332(2)(C), therefore a detailed statement under NEPA is not required. A copy of the draft EA can be viewed at *www.regulations.gov* (use the search term 1004–AE17, open the Docket Folder, and look under Supporting Documents) and at the address specified in the **ADDRESSES** section.

The proposed rule would not impact the environment significantly. For the most part, the proposed rule would in substance update the provisions of Order 5 and would involve changes that are of an administrative, technical, or procedural nature that would apply to the BLM's and the lessee's or operator's administrative processes. For example, the proposed rule would clarify the acceptable methods for estimating and documenting reported volumes of gas when metering equipment is malfunctioning or out of service. The proposed rule would also establish new requirements for gas sampling, including sampling location and methods, sampling frequency, analysis methods, and the minimum number of components to be analyzed. Finally, the proposed rule would establish new meter equipment, maintenance, inspection, and reporting standards. These changes would enhance the agency's ability to account for the gas produced from Federal and Indian lands, but should have minimal to no impact on the environment. We will consider any new information we receive during the public comment period for the proposed rule that may inform our analysis of the potential environmental impacts of the rule.

Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed rule would not have a significant adverse effect on the nation's energy supply, distribution or use, including a shortfall in supply or price increase. Changes in this proposed rule would strengthen the BLM's accountability requirements for operators under Federal and Indian oil and gas leases. As discussed above, these changes would prescribe a number of specific requirements for production measurement, including sampling, measuring, and analysis protocol; categories of violations; and reporting requirements. The proposal also establishes specific requirements related to the physical makeup of meter components. All of the changes would increase the regulated community's annual costs by about $46 million, or an average of approximately $13,000 per entity per year. There would be an additional one-time cost to industry of about $33 million to comply with the changes, or an average of approximately $8,900 per entity, phased in over a 3-year period. Entities with the greatest activity (*e.g.,* numerous FMPs) would incur higher costs. Additional information on these costs estimates can be found in the Economic and Threshold Analysis prepared for this proposed rule. The BLM is specifically seeking comment on that analysis and the assumptions used therein.

We expect that the proposed rule would not result in a net change in the quantity of oil and gas that is produced from oil and gas leases on Federal and Indian lands.

Information Quality Act

In developing this proposed rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Information Quality Act (Pub. L. 106–554, Appendix C Title IV, Section 515, 114 Stat. 2763A–153).

Clarity of the Regulations

Executive Order 12866 requires each agency to write regulations that are simple and easy to understand. We invite your comments on how to make these proposed regulations easier to understand, including answers to questions such as the following:

1. Are the requirements in the proposed regulations clearly stated?
2. Do the proposed regulations contain technical language or jargon that interferes with their clarity?
3. Does the format of the proposed regulations (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce their clarity?
4. Would the regulations be easier to understand if they were divided into more (but shorter) sections?
5. Is the description of the proposed regulations in the **SUPPLEMENTARY INFORMATION** section of this preamble helpful in understanding the proposed regulations? How could this description be more helpful in making the proposed regulations easier to understand?

Please send any comments you have on the clarity of the regulations to the address specified in the **ADDRESSES** section.

Authors

The principal authors of this rule are: Richard Estabrook of the BLM Washington Office; Gary Roth of the BLM Buffalo, Wyoming Field Office; Wanda Weatherford of the BLM Farmington, New Mexico Field Office; Clifford Johnson of the BLM Vernal, Utah Field Office; and Rodney Brashear of the BLM Durango, Colorado Field Office, assisted by Mike Wade of the BLM Washington Office; Joe Berry and Faith Bremner of the staff of BLM's Regulatory Affairs Division; John Barder, Office of Natural Resources Revenue; and Geoffrey Heath, Department of the Interior's Office of the Solicitor.

List of Subjects in 43 CFR part 3160

Administrative practice and procedure; Government contracts; Indians-lands; Mineral royalties; Oil and gas exploration; Penalties; Public lands—mineral resources; Reporting and recordkeeping requirements.

Lists of Subjects in 43 CFR Part 3170

Administrative practice and procedure; Immediate assessments, Incorporation by reference; Indians-lands; Mineral royalties; Oil and gas exploration; Oil and gas measurement; Penalties; Public lands—mineral resources.

Dated: October 1, 2015.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

43 CFR Chapter II

For the reasons set out in the preamble, the Bureau of Land Management proposes to amend 43 CFR part 3160 and add a new subpart 3175 to new 43 CFR part 3170 as follows:

PART 3160—ONSHORE OIL AND GAS OPERATIONS

■ 1. The authority citation for part 3160 continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

■ 2. Revise § 3162.7–3 to read as follows:

§ 3162.7–3 Measurement of gas.

All gas removed or sold from a lease, communitized area, or unit participating area must be measured under subpart 3175 of this title. All measurement must be on the lease, communitized area, or unit from which the gas originated and must not be commingled with gas originating from other sources unless approved by the authorized officer under subpart 3173 of this title.

■ 3. Amend § 3163.1 by revising paragraphs (a) introductory text, (a)(1), (a)(2), (b) introductory text, (b)(1), and (b)(2), removing paragraphs (c) and (d), and redesignating paragraph (e) as paragraph (c) and revising it. The revisions read as follows:

§ 3163.1 Remedies for acts of noncompliance.

(a) Whenever any person fails or refuses to comply with the regulations in this part, the terms of any lease or permit, or the requirements of any notice or order, the authorized officer shall notify that person in writing of the violation or default.

(1) For major violations, the authorized officer may also subject the person to an assessment of $1,000 per violation, per inspection.

(2) For minor violations, the authorized officer may also subject the person to an assessment of $250 per violation, per inspection.

* * * * *

(b) Certain instances of noncompliance are violations of such a nature as to warrant the imposition of immediate major assessments upon discovery as compared to those established by paragraph (a) of this section. Upon discovery the following violations, as well as the violations identified in subparts 3173, 3174, and 3175 of this part, will result in assessments in the specified amounts per violation, per inspection, without exception:

(1) For failure to install blowout preventer or other equivalent well control equipment, as required by the approved drilling plan, $1,000;

(2) For drilling without approval or for causing surface disturbance on Federal or Indian surface preliminary to drilling without approval, $1,000;

* * * * *

(c) On a case-by-case basis, the State Director may compromise or reduce assessments under this section. In compromising or reducing the amount of the assessment, the State Director will state in the record the reasons for such determination.

4. Amend § 3163.2 by revising paragraphs (a), (b), and (d) through (f), removing paragraphs (g), (j) and (k), redesignating paragraph (i) as paragraph (g) and revising it. The revisions read as follows:

§ 3163.2 Civil penalties.

(a)(1) Whenever any person fails or refuses to comply with any applicable requirements of the Federal Oil and Gas Royalty Management Act, any mineral leasing law, any regulation thereunder, or the terms of any lease or permit issued thereunder, the authorized officer will notify the person in writing of the violation, unless the violation was discovered and reported to the authorized officer by the liable person or the notice was previously issued under § 3163.1 of this subpart.

(2) Whenever a purchaser or transporter who is not an operating rights owner or operator fails or refuses to comply with 30 U.S.C. 1713 or applicable rules or regulations regarding records relevant to determining the quality, quantity, and disposition of oil or gas produced from or allocable to a Federal or Indian oil and gas lease, the authorized officer will notify the purchaser or transporter, as appropriate, in writing of the violation.

(b)(1) If the violation is not corrected within 20 days of such notice or report, or such longer time as the authorized officer may agree to in writing, the person will be liable for a civil penalty of up to $500 per violation for each day such violation continues, dating from the date of such notice or report. Any amount imposed and paid as assessments under § 3163.1(a)(1) of this subpart will be deducted from penalties under this section.

(2) If the violation specified in paragraph (a) of this section is not corrected within 40 days of such notice or report, or a longer period as the authorized officer may agree to in writing, the person will be liable for a civil penalty of up to $5,000 per violation for each day the violation continues, dating from the date of such notice or report. Any amount imposed and paid as assessments under § 3163.1(a)(1) of this subpart will be deducted from penalties under this section.

* * * * *

(d) Whenever a transporter fails to permit inspection for proper documentation by any authorized representative, as provided in § 3162.7–1(c) of this title, the transporter shall be liable for a civil penalty of up to $500 per day for the violation, dating from the date of notice of the failure to permit inspection and continuing until the proper documentation is provided. If the violation continues beyond 20 days, the authorized officer will revoke the transporter's authority to remove crude oil produced from, or allocated to, any Federal or Indian lease under the authority of that authorized officer. This revocation of the transporter's authority will continue until the transporter provides proper documentation and pays any related penalty.

(e) Any person shall be liable for a civil penalty of up to $10,000 per violation for each day such violation continues, if the person:

(1) Fails or refuses to permit lawful entry or inspection authorized by § 3162.1(b) of this title; or

(2) Knowingly or willfully fails to notify the authorized officer by letter or Sundry Notice, Form 3160–5 or orally to be followed by a letter or Sundry Notice, not later than the 5th business day after any well begins production on which royalty is due, or resumes production in the case of a well which has been off of production for more than 90 days, from a well located on a lease site, or allocated to a lease site, of the date on which such production began or resumed.

(f) Any person shall be liable for a civil penalty of up to $25,000 per violation for each day such violation continues, if the person:

(1) Knowingly or willfully prepares, maintains or submits false, inaccurate or misleading reports, notices, affidavits, records, data or other written information required by this part; or

(2) Knowingly or willfully takes or removes, transports, uses or diverts any oil or gas from any Federal or Indian lease site without having valid legal authority to do so; or

(3) Purchases, accepts, sells, transports or conveys to another any oil or gas knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted from a Federal or Indian lease site.

(g) Civil penalties provided by this section are supplemental to, and not in derogation of, any other penalties or assessments for noncompliance in any other provision of law, except as provided in paragraphs (a) and (b) of this section.

* * * * *

§ 3164.1 [Amended]

■ 5. Amend § 3164.1, in paragraph (b), by removing the fifth entry in the chart (the reference to Order No. 5, Measurement of gas).

■ 6. Amend § 3165.3 by revising paragraph (a) to read as follows:

§ 3165.3 Notice, State Director review and hearing on the record.

(a) *Notice.* (1) Whenever any person, including an operating rights owner or operator, as appropriate, fails to comply with any provisions of the lease, the regulations in this part, applicable orders or notices, or any other appropriate order of the authorized officer, the authorized officer will issue a written notice or order to the appropriate party and the lessee(s) to remedy any defaults or violations.

* * * * *

PART 3170—ONSHORE OIL AND GAS PRODUCTION

■ 7. The authority citation for part 3170, proposed to be added on July 13, 2015 (80 CFR 40768), continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740

■ 8. Add subpart 3175 to part 3170, proposed to be added on July 13, 2015 (80 FR 40768), to read as follows:

Subpart 3175—Measurement of Gas

Sec.

§ 3175.10 Definitions and acronyms.

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

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:

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

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

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 making adjustments to the transducer, but prior to returning the transducer to service.

Atmospheric pressure means the pressure exerted by the weight of the atmosphere at a specific location.

Beta ratio means the measured diameter of the orifice bore divided by the measured 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.

British thermal unit (Btu) means the amount of heat needed to raise the temperature of one pound of water by 1°F.

Component-type electronic gas measurement system means an electronic gas measurement system comprised of transducers and a flow computer, each identified by a separate make and model from which performance specifications are obtained.

Configuration log means a list of all fixed or user-programmable parameters used by the flow computer that could affect the calculation or verification of flow rate, volume, or heating value.

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

Effective date of a spot or composite gas sample means the first day on which the relative density and heating value determined from the sample are used in calculating the volume and quality on which royalty is based.

Electronic gas measurement (EGM) means all hardware and software necessary to convert the static pressure, differential pressure, and flowing temperature developed as part of a primary device, to a quantity, rate, or quality measurement that is used to determine Federal royalty. For orifice meters, this includes the differential-pressure transducer, static-pressure transducer, flowing-temperature transducer, on-line gas chromatograph (if used), flow computer, display, memory, and any internal or external processes used to edit and present the data or values measured.

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

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

GPA (followed by a number) means, unless otherwise specified, a standard prescribed by the Gas Processors Association, with the number referring to the specific standard.

Heating value means the gross heat energy released by the complete combustion of one standard cubic foot of gas at 14.73 pounds per square inch (psi) and 60° F.

High-volume facility measurement point or high-volume FMP means any FMP that measures more than 100 Mcf/day, but less than or equal to 1,000 Mcf/day, averaged over the previous 12 months or the life of the FMP, whichever is shorter.

Hydrocarbon dew point means the temperature at which hydrocarbon liquids begin to form. For the purpose of this regulation, the hydrocarbon dew point is the flowing temperature of the gas measured at the FMP, unless otherwise approved by the AO.

Integration means a process by which the lines on a circular chart (differential pressure, static pressure, and flowing temperature) used in conjunction with a mechanical chart recorder are re-traced or interpreted in order to determine the volume that is represented by the area under the lines. The result of an integration is an integration statement which documents the values determined from the integration.

Live input variable means a datum that is automatically obtained in real time by an EGM system.

Low-volume facility measurement point or low-volume FMP means any FMP that measures more than 15 Mcf/day, but less than or equal to 100 Mcf/day, averaged over the previous 12 months, or the life of the FMP, whichever is shorter.

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

Marginal-volume facility measurement point or marginal-volume FMP means any FMP that measures 15 Mcf/day or less averaged over the previous 12 months, or the life of the FMP, whichever is shorter, unless the AO approves a higher rate.

Mean means the sum of all the members of a data set divided by the number of items in the data set.

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 percent.

Normal flowing point means the differential pressure, static pressure, and flowing temperature at which the FMP normally operates when gas is flowing through it.

Primary device means the equipment installed in a pipeline that creates a measureable and predictable pressure drop in response to the flow rate of fluid through the pipeline. It includes the pressure-drop device, device holder, pressure taps, required lengths of pipe upstream and downstream of the pressure-drop device, and any flow conditioners that may be used.

Quantity transaction record (QTR) means a report generated by EGM equipment that summarizes the daily and hourly volume calculated by the flow computer and the average or totals of the dynamic data that is used in the calculation of volume.

Reynolds number means the ratio of the inertial forces to the viscous forces of the fluid flow defined as:

$$R_e = \frac{V\rho D}{\mu}$$

where:

R_e = the Reynolds number
V = velocity
ρ = fluid density
D = inside meter tube diameter
μ = fluid viscosity

Redundancy verification means a process of verifying the accuracy of an EGM by comparing the readings of two sets of transducers placed on the same meter.

Secondary device means the differential-pressure, static-pressure, and temperature transducers in an EGM system, or a mechanical recorder, including the differential pressure, static pressure, and temperature elements, and the clock, pens, pen linkages, and circular chart.

Self-contained EGM system means an EGM system where the transducers and flow computer are identified by a single make and model number from which the performance specifications for the transducers and flow computer are obtained. Any change to the make or model number of a transducer or flow computer changes the EGM system to a component-type EGM system.

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.

Significant digit means any digit of a number that is known with certainty.

Standard cubic foot (scf) means a cubic foot of gas at 14.73 psia and 60° F.

Standard deviation means a measure of the variation in a distribution, equal to the square root of the arithmetic mean of the squares of the deviations from the arithmetic mean.

Statistically significant means the difference between two data sets that exceeds the threshold of significance.

Tertiary device means, for EGM systems, the flow computer and associated memory, calculation, and display functions.

Threshold of significance means the maximum difference between two data sets (a and b) that can be attributed to uncertainty effects. The threshold of significance is determined 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

Transducer means an electronic device that converts a physical property such as pressure, temperature, or electrical resistance into an electrical output signal that varies proportionally with the magnitude of the physical property. Typical output signals are in the form of electrical potential (volts), current (milliamps), or digital pressure or temperature readings. The term transducer includes devices commonly referred to as transmitters.

Turndown means a reduction of the measurement range of a transducer in order to improve measurement accuracy at the lower end of its scale. It is typically expressed as the ratio of the upper range limit to the upper calibrated limit.

Type test means a test on a representative number of a specific make, model, and range of a transducer to determine its performance over a range of operating conditions.

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.

Upper range limit (URL) means the maximum value that a transducer is designed to measure.

Verification means the process of determining the amount of error in a differential pressure, static pressure, or temperature transducer or element by comparing the readings of the transducer or element with the readings from a certified test device with known accuracy.

Very-high-volume facility measurement point or very-high-volume FMP means any FMP that measures more than 1,000 Mcf/day averaged over the previous 12 months or the life of the FMP, whichever is shorter.

(b) As used in this subpart the following additional acronyms carry the meaning prescribed:

GARVS means the BLM's Gas Analysis Reporting and Verifications System

GC means gas chromatograph.

GPA means the Gas Processors Association.

Mcf means 1,000 standard cubic feet.

psia means pounds per square inch—absolute.

psig means pounds per square inch—gauge.

WIS means Well Information System or any successor electronic system.

§ 3175.20 General requirements.

Measurement of all gas removed or sold from Federal and Indian leases and unit PAs or CAs that include one or more Federal or Indian leases, must comply with the standards prescribed in this subpart, except as otherwise approved under § 3170.6 of this subpart.

§ 3175.30 Specific performance requirements.

(a) *Flow rate measurement certainty 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) The determination of 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, or 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 BLM at the time of uncertainty determination; or

(ii) The average flowing parameters from the previous day, as required under § 3175.101(b)(4)(ix) through (xi) of this subpart.

(b) *Heating value certainty levels.* (1) For high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within ±2 percent.

(2) For very-high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within ±1 percent.

(c) *Bias.* For low-volume, high-volume, and very-high-volume FMPs, the measuring equipment used for both flow rate and heating value determination must achieve measurement without statistically significant bias.

(d) *Verifiability.* An operator may not use measurement equipment for which the accuracy and validity of any input, factor, or equation used by the measuring equipment to determine quantity, rate, or heating value is not independently verifiable by the BLM. Verifiability includes the ability to independently recalculate the volume, rate, and heating value based on source records and field observations.

§ 3175.31 Incorporation by reference.

(a) Certain material identified in paragraphs (b) and (c) of this section 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 that specified in this section, the BLM must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the Bureau of Land Management, Division of Fluid Minerals, 20 M Street SE., Washington, DC 20003, 202–912–7162, and at all BLM offices with jurisdiction over oil and gas activities. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or go to *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.* In addition, the material incorporated by reference is available from the sources of that material identified in paragraphs (b) and (c) of this section, as follows:

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005; telephone 202–682–8000. API also offers free, read-only access to some of the material at *www.publications.api.org.*

(1) API Manual of Petroleum Measurement Standards (MPMS) Chapter 14, Section 1, Collecting and Handling of Natural Gas Samples for Custody Transfer, Sixth Edition, February 2006, Reaffirmed 2011 (''API 14.1.12.10''), incorporation by reference (IBR) approved for § 3175.114(b).

(2) API MPMS Chapter 14, Section 2, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases, Second Edition, August 1994, Reaffirmed March 1, 2006 (''API 14.2''), IBR approved for §§ 3175.103(a)(1)(ii) and 3175.120(d).

(3) API MPMS, Chapter 14, Section 3, Part 1, General Equations and Uncertainty Guidelines, Fourth Edition, September 2012, Errata, July 2013. (''API 14.3.1.4.1''), IBR approved for § 3175.80 Table 1.

(4) API MPMS Chapter 14, Section 3, Part 2, Specifications and Installation Requirements, Fourth Edition, April 2000, Reaffirmed 2011 (''API 14.3.2,'' ''API 14.3.2.4,'' ''API 14.3.2.5.1 through API 14.3.2.5.4,'' ''API 14.3.2.5.5.1 through API 14.3.2.5.5.3,'' ''API 14.3.2.6.2,'' ''API 14.3.2.6.3,'' ''API 14.3.2.6.5,'' and ''API 14.3.2, Appendix 2–D''), IBR approved for §§ 3175.46(b) and (c), 3175.80 Table 1, 3175.80(c), 3175.80(d), 3175.80(e)(4), 3175.80(f), 3175.80(g), 3175.80(g)(3), 3175.80(i), 3175.80(j), 3175.80(k), 3175.80(l), and 3175.112(b)(1).

(5) API MPMS Chapter 14, Section 3, Part 3, Natural Gas Applications, Fourth Edition, November 2013 (''API 14.3.3,'' ''API 14.3.3.4,'' and ''API 14.3.3.5.'' and ''API 14.3.3.5.6,''), IBR approved for §§ 3175.94(a)(1) and 3175.103(a)(1)(i).

(6) API MPMS, Chapter 14, 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 (''API 14.5,'' ''API 14.5.3.7,'' and ''API 14.5.7.1''), IBR approved for §§ 3175.120(c) and 3175.125 (a)(1).

(7) API MPMS Chapter 21, Section 1, Electronic Gas Measurement, Second Edition, February 2013 (''API 21.1,'' ''API 21.1.4,'' ''API 21.1.4.4.5,'' ''API 21.1.5.2,'' ''API 21.1.5.3,'' ''API 21.1.5.4,'' ''API 21.1.5.4.2,'' ''API 21.1.5.5,'' ''API 21.1.5.6,'' ''API 21.1.7.3,'' ''API 21.1.7.3.3,'' ''API 21.1.8.2,'' ''API 21.1.8.2.2.2, Equation 24,'' ''API 21.1.9,'' ''API 21.1 Annex B,'' ''API 21.1 Annex G,'' ''API 21.1 Annex H, Equation H.1,'' and ''API 21.1 Annex I''), IBR approved for §§ 3175.100 Table 3, 3175.101(e), 3175.102(a)(2), 3175.102(c), 3175.102(c)(4), 3175.102(c)(5), 3175.102(d), 3175.102(e)(2)(v), 3175.103(b), 3175.103(c), 3175,104(a), 3175.104(b), 3175.104(b)(2), 3175.104(c), and 3175.104(d).

(8) API MPMS Chapter 22, Section 2, Differential Pressure Flow Measurement Devices, First Edition, August 2005, Reaffirmed 2012 (''API 22.2''), IBR approved for § 3175.47 (a), (b), and (c).

(c) Gas Processors Association (GPA), 6526 E. 60th Street, Tulsa, OK 74145; telephone 918–493–3872.

(1) GPA Standard 2166–05, Obtaining Natural Gas Samples for Analysis by Gas Chromatography, Revised 2005 (''GPA 2166–05 Section 9.1,'' ''GPA 2166.05 Section 9.5,'' ''GPA 2166–05 Sections 9.7.1 through 9.7.3,'' ''GPA 2166–05 Appendix A,'' ''GPA 2166–05 Appendix B.3,'' ''GPA 2166–05 Appendix D''), IBR approved for §§ 3175.113(c)(3), 3175.113(d)(1)(ii), 3175.113(d)(1)(iii), 3175.114(a)(1), 3175.114(a)(2), 3175.114(a)(3), 3175.117(a).

(2) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Revised 2000 (''GPA 2261–00'', ''GPA 2261–00, Section 4,'' GPA 2261–00, Section 5,'' ''GPA 2261–00, Section 9''), IBR approved for § 3175.118(a)(b)(c) and (e).

(3) GPA Standard 2198–03, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends, Revised 2003. (''GPA 2198–03''), IBR approved for §§ 3175.118(h), 3175.118(i)(7). Note 1 to § 3175.31(b) and (c): You may also be able to purchase these standards from the following resellers: Techstreet, 3916 Ranchero Drive, Ann Arbor, MI 48108; telephone 734–780–8000; *www.techstreet.com/api/apigate.html*; IHS Inc., 321 Inverness Drive South, Englewood, CO 80112; 303–790–0600; *www.ihs.com*; SAI Global, 610 Winters Avenue, Paramus, NJ 07652; telephone 201–986–1131.

§ 3175.40 Measurement equipment approved by standard or make and model.

The measurement equipment described in §§ 3175.41 through 3175.48 is approved for use at FMPs under the conditions and circumstances stated in those sections if it meets or exceeds the minimum standards prescribed in this subpart.

§ 3175.41 Flange-tapped orifice plates.

Flange-tapped orifice plates constructed and installed under § 3175.80 of this subpart are approved for use.

§ 3175.42 Chart recorders.

Chart recorders used in conjunction with approved differential-type meters that are installed, operated, and maintained under § 3175.90 of this subpart are approved for use for low-volume and marginal-volume FMPs only, and are not approved for high-volume or very-high-volume FMPs.

§ 3175.43 Transducers.

(a) A specific make, model, and URL of a transducer used in conjunction with differential meters for high-volume or very-high-volume FMPs is approved for use if it meets the following requirements:

(1) It has been type-tested under § 3175.130 of this subpart;

(2) The documentation required in § 3175.130 of this subpart has been submitted to the PMT; and

(3) It has been placed on the list of type-tested equipment maintained at *www.blm.gov*.

(b) All transducers used at marginal- and low-volume FMPs are approved for use.

§ 3175.44 Flow computers.

(a) A specific make and model of flow computer and software version is approved for use if it meets the following requirements:

(1) The documentation required in § 3175.140 of this subpart has been submitted to the PMT;

(2) The PMT has determined that the flow computer and software version passed the type-testing required in § 3175.140 of this subpart, except as provided in paragraph (b) of this section; and

(3) It has been placed on the list of approved equipment maintained at *www.blm.gov*.

(b) Software revisions that do not affect or that do not have the potential to affect determination of flow rate, determination of volume, and data or calculations used to verify flow rate or volume are not required to be type-tested.

§ 3175.45 Gas chromatographs.

GCs that meet the standards in §§ 3175.117 and 3175.118 of this subpart for determining heating value and relative density are approved for use.

§ 3175.46 Isolating flow conditioners.

An approved make and model of isolating flow conditioner that is listed at *www.blm.gov* and used in conjunction with flange-tapped orifice plates is approved for use if it is installed, operated, and maintained in compliance with BLM requirements specified at *www.blm.gov*. Approval of a particular make and model is obtained as prescribed in this section.

(a) All testing required under this section must be performed at a laboratory that is NIST traceable and not affiliated with the flow-conditioner manufacturer.

(b) The operator or manufacturer must test the flow conditioner under API 14.3.2, Appendix 2–D (incorporated by reference, see § 3175.31), and under any additional test protocols that the BLM requires that are posted on the BLM's Web site at *www.blm.gov*, and submit all test data to the BLM.

(c) The PMT will review the test data to ensure that the device meets the requirements of API 14.3.2, Appendix 2–D (incorporated by reference, see § 3175.31) and make a recommendation to the BLM to either approve use of the device, disapprove use of the device, or approve it with conditions for its use.

(d) If approved, the BLM will add the approved make and model, and any applicable conditions of use, to the list maintained at *www.blm.gov*.

§ 3175.47 Differential primary devices other than flange-tapped orifice plates.

The make and model of a differential primary device that is listed at *www.blm.gov* is approved for use if it is installed, operated, and maintained in compliance with BLM requirements specified at *www.blm.gov*. Approval of a particular make and model is obtained as follows:

(a) The primary device must be tested under API 22.2 (incorporated by reference, see § 3175.31), and under any additional protocols that the BLM requires that are posted on the BLM's Web site at *www.blm.gov*, at a laboratory that is NIST traceable and not affiliated with the primary device manufacturer;

(b) The operator must submit to the BLM all test data required under API 22.2 (incorporated by reference, see § 3175.31);

(c) The PMT will review the test data to ensure that the primary device meets the requirements of API 22.2 (incorporated by reference, see § 3175.31) and § 3175.30(c) and (d) of this subpart and make a recommendation to the BLM to either approve use of the device, disapprove use of the device, or approve its use with conditions.

(d) If approved, the BLM will add the approved make and model, and any applicable conditions of use, to the list maintained at *www.blm.gov*.

§ 3175.48 Linear measurement devices.

The BLM may approve linear measurement devices such as ultrasonic meters, Coriolis meters, positive displacement meters, and turbine meters on a case-by-case basis. To request approval, the operator must submit to the AO all data that the BLM requires. The PMT will review the data to determine whether the meter meets the requirements of § 3175.30 of this subpart, and make a recommendation to the BLM, which will either approve use of the device, disapprove use of the device, or approve its use with conditions.

§ 3175.60 Timeframes for compliance.

(a) The measuring procedures and equipment installed at any FMP on or after [EFFECTIVE DATE OF THE FINAL RULE] must comply with all of the requirements of this subpart upon installation.

(b) Measuring procedures and equipment at any FMP in place before [EFFECTIVE DATE OF FINAL RULE] must comply with the requirements of this subpart within the timeframes specified in this paragraph.

(1) Very-high-volume FMPs must comply with:

(i) All of the requirements of this subpart except as specified in paragraph (b)(1)(ii) of this section by [SIX MONTHS AFTER THE EFFECTIVE DATE OF THE FINAL RULE]; and

(ii) The gas analysis reporting requirements of § 3175.120(f) of this subpart beginning on [EFFECTIVE DATE OF FINAL RULE].

(2) High-volume FMPs must comply with:

(i) All of the requirements of this subpart except as specified in paragraph (b)(2)(ii) of this section by [ONE YEAR AFTER THE EFFECTIVE DATE OF THE FINAL RULE]; and

(ii) The gas analysis reporting requirements of § 3175.120(f) of this subpart beginning on [EFFECTIVE DATE OF FINAL RULE].

(3) Low-volume FMPs must comply with all of the requirements of this subpart by [TWO YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE].

(4) Marginal-volume FMPs must comply with all of the requirements of this regulation by [THREE YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE].

(c) During the phase-in timeframes in paragraph (b) of this section, measuring procedures and equipment in place before [EFFECTIVE DATE OF THE FINAL RULE] must comply with the requirements of the predecessor rule to this subpart, *i.e.,* Onshore Oil and Gas Order No. 5, Measurement of Gas, 54 FR 8100 (Feb. 24, 1989), and applicable NTLs, COAs, and written orders.

(d) The applicability of existing NTLs, variance approvals, and written orders that establish requirements or standards related to gas measurement are rescinded as of:

(i) [SIX MONTHS AFTER THE EFFECTIVE DATE OF THE FINAL RULE] for very-high-volume FMPs;

(ii) [ONE YEAR AFTER THE EFFECTIVE DATE OF THE FINAL RULE] for high-volume FMPs;

(iii) [TWO YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE] for low-volume FMPs; and

(iv) [THREE YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE] for marginal-volume FMPs;

§ 3175.70 Measurement location.

(a) *Commingling and allocation.* Gas produced from a lease, unit PA, or CA may not be commingled with production from other leases, unit PAs, or CAs or non-Federal properties before the point of royalty measurement, unless prior approval is obtained under 43 CFR subpart 3173.

(b) *Off-lease measurement.* Gas must be measured on the lease, unit, or CA unless approval for off-lease measurement is obtained under 43 CFR subpart 3173.

§ 3175.80 Flange-tapped orifice plates (primary devices).

The following table lists the standards in this subpart and the API standards that the operator must follow to install and maintain flange-tapped orifice plates. A requirement applies when a column is marked with an ''x'' or a number.

TABLE 1—STANDARDS FOR FLANGE-TAPPED ORIFICE PLATES

Subject	Reference (API standards incorporated by reference, see § 3175.31)	M	L	H	V
Fluid conditions	API 14.3.1.4.1	n/a	x	x	x
Orifice plate construction and condition	API 14.3.2.4	x	x	x	x
Orifice plate eccentricity and perpendicularity	API 14.3.2.6.2	x	x	x	x
Beta ratio range	§ 3175.80(a)	n/a	x	x	x
Minimum orifice size	§ 3175.80(b)	n/a	n/a	x	x
New FMP orifice plate inspection *	§ 3175.80(c)	x	x	x	x
Routine orifice plate inspection frequency, in months. *	§ 3175.80(d)	12	6	3	1
Documentation of orifice plate inspection	§ 3175.80(e)	x	x	x	x
Meter tube construction and condition	§ 3175.80(f)	n/a	x	x	x
Flow conditioners including 19-tube bundles	§ 3175.80(g)	n/a	x	x	x
Visual meter tube inspection frequency, in years. *	§ 3175.80(h)	n/a	5	2	1
Detailed meter tube inspection frequency, in years. *	§ 3175.80(i)	n/a	**	10	5
Documentation of meter tube inspection	§ 3175.80(j)	n/a	x	x	x
Meter tube length	§ 3175.80(k)	n/a	x	x	x
Thermometer wells	§ 3175.80(l)	n/a	x	x	x
Sample probe location	§ 3175.80(m)	x	x	x	x
Notification of meter tube installation or inspection	§ 3175.80(n)	n/a	x	x	x

M=Marginal-volume FMP; L=Low-volume FMP; H=High-volume FMP; V=Very-high-volume FMP; * = Immediate assessment for non-compliance under § 3175.150 of this subpart; **=If ordered by the AO after notification required under § 3175.80(h)(3).

Except as stated in the text of this section or as prescribed in Table 1, the standards and requirements in this section apply to all flange-tapped orifice plates.

(a) The Beta ratio must be no less than 0.10 and no greater than 0.75.

(b) The orifice bore diameter must be no less than 0.45 inches.

(c) For FMPs measuring production from wells first coming into production (including FMPs already measuring production from one or more other wells), the operator must inspect the orifice plate upon installation and then every 2 weeks thereafter. If the inspection shows that the orifice plate does not comply with API 14.3.2.4 and API 14.3.2.6.2 (both incorporated by reference, see § 3175.31), the operator must replace the orifice plate. When the bi-weekly inspection shows that the orifice plate complies with API 14.3.2.4 and API 14.3.2.6.2 (both incorporated by reference, see § 3175.31), the operator thereafter must inspect the orifice plate as prescribed in paragraph (d) of this section.

(d) The operator must pull and inspect the orifice plate at the frequency (in months) identified in Table 1 during verification of the secondary device. The operator must replace orifice plates that do not comply with API 14.3.2.4 or API 14.3.2.6.2 (both incorporated by reference, see § 3175.31) with an orifice plate that does comply with these standards.

(e) The operator must retain documentation for every plate inspection and must include that documentation as part of the verification report (see § 3175.92(d), mechanical recorders, or § 3175.102(e), EGM systems, of this subpart). The operator must provide that documentation to the BLM upon request. The documentation must include:

(1) The information required in § 3170.7(g) of this subpart;

(2) Plate orientation (bevel upstream or downstream);

(3) Measured orifice bore diameter;

(4) Plate condition (compliance with API 14.3.2.4 (incorporated by reference, see § 3175.31));

(5) The presence of oil, grease, paraffin, scale, or other contaminants found on the plate;

(6) Time and date of inspection; and

(7) Whether or not the plate was replaced.

(f) Meter tubes must meet the requirements of API 14.3.2.5.1 through API 14.3.2.5.4 (all incorporated by reference, see § 3175.31). The following exception is allowed for meter tubes at low-volume FMPs only if:

(1) The difference between the maximum and the minimum inside diameter of the meter tube measured 1 inch upstream of the orifice plate does not exceed the following tolerance:

$$T = 5.0\beta^2 - 2.5\beta + 0.2$$

Where:

T = tolerance of average diameter, in percent
β = the Beta ratio

and

(2) The difference between any measured inside diameter of the meter tube and the average inside diameter of the meter tube measured 1 inch downstream of the orifice plate does not exceed the tolerance given by the equation in paragraph (f)(1) of this section.

(g) If flow conditioners are used, they must be either isolating-flow conditioners approved by the BLM and installed under BLM requirements (see § 3175.46 of this subpart) or 19-tube-bundle flow straighteners constructed and located in compliance with API 14.3.2.5.5.1 through API 14.3.2.5.5.3 (all incorporated by reference, see § 3175.31).

(h) *Visual meter tube inspection.* The operator must:

(1) Visually inspect meter tubes within the timeframe (in years) specified in Table 1.

(2) Use a borescope or equivalent device, capable of determining the condition of the inside of the meter tube along the entire upstream and downstream lengths required by paragraph (k) of this section, including the tap holes and the plate holder. The visual inspection must be able to identify obstructions, pitting, and buildup of foreign substances (*e.g.,* grease and scale).

(3) Notify the AO within 72 hours if a visual inspection identifies conditions that indicate the meter tube does not comply with API 14.3.2.5.1 through API 14.3.2.5.4 (all incorporated by reference, see § 3175.31).

(4) Maintain documentation of the findings from the visual meter tube inspection including:

(i) The information required in § 3170.7(g) of this subpart;

(ii) The time and date of inspection; and

(iii) The type of equipment used to make the inspection;

(iv) A description of findings, including location and severity of pitting, obstructions, and buildup of foreign substances.

(5) Conducting a detailed inspection such as that required under paragraph (i) of this section in lieu of a visual inspection satisfies the requirement of this paragraph.

(i) *Detailed meter tube inspection.* (1) The operator must physically measure and inspect the meter tube used in a high-volume or very-high-volume FMP at the frequency (in years) identified in Table 1, to determine if the meter tube complies with API 14.3.2.5.1 through API 14.3.2.5.4 (all incorporated by reference, see § 3175.31).

(2) The AO may adjust the detailed meter inspection frequencies if a visual inspection under paragraph (h) of this section identifies issues regarding compliance with the identified API standards or the operator provides documentation that demonstrates that a different frequency is warranted.

(3) The AO may require additional inspections if conditions warrant, such as corrosive- or erosive-flow conditions (*e.g.,* high H_2S or CO_2 content) or signs of physical damage to the meter tube.

(4) If a visual inspection of a meter at a low-volume FMP reveals noncompliance with any requirement of API 14.3.2.5.1 through API 14.3.2.5.4 (all incorporated by reference, see § 3175.31), or if the meter tube operates in corrosive- or erosive-flow conditions or has signs of physical damage, the AO may require a detailed inspection.

(j) The operator must retain documentation demonstrating that the meter tube complies with API 14.3.2.5.1 through API 14.3.2.5.4 (all incorporated by reference, see § 3175.31) and showing all required measurements. The operator must provide such documentation to the BLM upon request for every meter-tube inspection (see Appendix 1 to this subpart for sample inspection sheet). Documentation must also include the information required in § 3170.7(g) of this subpart.

(k) *Meter tube lengths.* (1) For all very-high-volume FMPs, all high-volume FMPs, and low-volume FMPs that utilize 19- tube-bundle flow straighteners, meter-tube lengths and the location of 19-tube-bundle flow straighteners, if applicable, must comply with API 14.3.2.6.3 (incorporated by reference, see § 3175.31). If the calculated diameter ratio (β) falls between the values in Tables 2–7, 2–8a, or 2–8b of that API section, the length identified for the larger diameter ratio in the Table is the minimum requirement for meter-tube length and determines the location of the end of the 19-tube-bundle flow straightener closest to the orifice plate. For example, if the calculated diameter ratio is 0.41, use the table entry for a 0.50 diameter ratio.

(2) For low-volume FMPs that do not utilize 19-tube-bundle flow straighteners, meter tube lengths may either comply with paragraph (k)(1) of this section or with the lengths calculated as follows:

Upstream disturbance	Minimum upstream meter tube length * (nominal pipe diameters, D)	Minimum downstream meter tube length * (nominal pipe diameters, D)
Double out-of-plane elbows; less than 10D separation (Figure 5, AGA Report No. 3, 1985).	$125\beta^3 - 87.5\beta^2 + 36.3\beta + 13.3$	$3.03\beta + 2.16$
Double in-plane elbows; less than 10D separation (Figure 6, AGA Report No. 3, 1985).	B<0.4: 8.7 $\beta \geq 0.4$: $83.8\beta^2 - 59.8\beta + 19.2$.	
Double in-plane elbows; greater than 10D separation (Figure 7, AGA Report No. 3, 1985).	$\beta<0.41$: 6.0 $\beta \geq 0.41$: $84.8\beta^2 - 67.5\beta + 19.4$.	
Concentric reducer or expander (Figure 8, AGA Report No. 3, 1985)	B<0.35: 6.0 $\beta \geq 0.35$: $31.3\beta^2 - 15.6\beta + 7.64$.	
All other configurations (Figure 4, AGA Report No. 3, 1985)	$125\beta^3 - 87.5\beta^2 + 36.3\beta + 13.3$.	

NOTES: (1) β is the Beta ratio; (2) To obtain the lengths in inches, you must multiply the result of the equation by the nominal pipe diameter of the meter tube (*e.g.* 2-inch, 3-inch, 4-inch); (3) The equations are an approximation of the meter tube length figures from AGA Report No. 3 (1985).

(l) *Thermometer wells.* (1) Thermometer wells for determining the flowing temperature of the gas as well as thermometer wells used for verification (test well) must be located in compliance with API 14.3.2.6.5 (incorporated by reference, see § 3175.31).

(2) Thermometer wells must be exposed to the same ambient conditions as the primary device. For example, if the primary device is located in a heated meter house, the thermometer well also must be located in the same heated meter house.

(3) 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.

(4) Thermometer wells used to measure or verify flowing temperature must contain a thermally conductive liquid.

(m) The sampling probe must be located as specified in § 3175.112(b) of this subpart.

(n) The operator must notify the AO at least 72 hours before a visual or detailed meter-tube inspection or installation of a new meter tube.

§ 3175.90 Mechanical recorder (secondary device).

(a) The operator may use a mechanical recorder as a secondary device only on marginal-volume and low-volume FMPs.

(b) The following table lists the standards that the operator must follow to install and maintain mechanical recorders. A requirement applies when a column is marked with an ''x'' or a number.

TABLE 2—STANDARDS FOR MECHANICAL RECORDERS

Subject	Reference	M	L
Applications for use	§ 3175.90(a)	x ..	x
Manifolds and gauge/impulse lines.	§ 3175.91(a)	n/a	x
Differential pressure pen position.	§ 3175.91(b)	n/a	x
Flowing temperature recording.	§ 3175.91(c)	n/a	x
On-site data requirements.	§ 3175.91(d)	x ..	x
Operating within the element ranges.	§ 3175.91(e)	x ..	x
Verification after installation or following repair*.	§ 3175.92(a)	x ..	x
Routine verification and verification frequency, in months*.	§ 3175.92(b)	6 ..	3
Routine verification procedures.	§ 3175.92(c)	x ..	x
Documentation of verification.	§ 3175.92(d)	x ..	x
Notification of verification.	§ 3175.92(e)	x ..	x
Volume correction	§ 3175.92(f)	n/a	x
Test equipment re-certification.	§ 3175.92(g)	x ..	x
Integration statement requirements.	§ 3175.93	x ..	x
Volume determination.	§ 3175.94(a)	x ..	x
Atmospheric pressure.	§ 3175.94(b)	x ..	x

M=Marginal-volume FMP; L=Low-volume FMP; * = Immediate assessment for non-compliance under § 3175.150 of this subpart.

§ 3175.91 Installation and operation of mechanical recorders.

(a) Gauge lines connecting the pressure taps to the mechanical recorder must:

(1) Have an internal diameter not less than 3/8'', including ports and valves;

(2) Be constructed of stainless steel;

(3) Be sloped upwards from the pressure taps at a minimum pitch of 1 inch per foot of length;

(4) Be the same internal diameter along their entire length;

(5) Not include any tees, except for the static pressure line;

(6) Not be connected to more than one differential-pressure bellows and static-pressure element, or to any other device; and

(7) Be no longer than 6 feet.

(b) The differential pressure pen must record at a minimum reading of 10 percent of the differential-bellows range for the majority of the flowing period.

(c) The flowing temperature of the gas must be continuously recorded and used in the volume calculations under § 3175.94(a)(1) of this subpart.

(d) The following information must be maintained at the FMP in a legible condition, in compliance with § 3170.7(g) of this subpart, and accessible to the AO at all times:

(1) Differential-bellows range;

(2) Static-pressure-element range;

(3) Temperature-element range;

(4) Relative density (specific gravity);

(5) Static-pressure units of measure (psia or psig);

(6) Meter elevation;

(7) Meter-tube inside diameter;

(8) Primary device type;

(9) Orifice-bore or other primary-device dimensions necessary for device verification, Beta- or area-ratio determination, and gas-volume calculation;

(10) Make, model, and location of approved isolating flow conditioners, if used;

(11) Location of the downstream end of 19-tube-bundle flow straighteners, if used;

(12) Date of last primary-device inspection; and

(13) Date of last verification.

(e) The differential pressure, static pressure, and flowing temperature elements must be operated between the lower- and upper-calibrated limits of the respective elements.

§ 3175.92 Verification and calibration of mechanical recorders.

(a) *Verification after installation or following repair.* (1) Before performing any verification required in this part, the operator must perform a leak test. The verification must not proceed until no leaks are present. The leak test must be conducted in a manner that will detect leaks in the following:

(i) All connections and fittings of the secondary device, including meter manifolds and verification equipment;

(ii) The isolation valves; and

(iii) The equalizer valves.

(2) The time lag between the differential and static pen must be adjusted, if necessary, to be 1/96 of the chart rotation period, measured at the chart hub. For example, the time lag is 15 minutes on a 24-hour test chart and 2 hours on an 8-day test chart.

(3) The meter's differential pen arc must be adjusted, if necessary, to duplicate the test chart's time arc over the full range of the test chart.

(4) The as-left values must be verified in the following sequence against a certified pressure device for the differential pressure 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 tolerances shown in the following table, the operator must replace and verify the element whose readings were outside the applicable tolerances before returning the meter to service.

TABLE 2–1—MECHANICAL RECORDER TOLERANCES

Element	Allowable error
Differential Pressure	±0.5%
Static Pressure	±1.0%
Temperature	±2 °F

(7) If the static-pressure pen is offset for atmospheric pressure:

(i) The atmospheric pressure must be calculated under Attachment 2 of this subpart; and

(ii) 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, static pressure, and temperature elements must be verified under the requirements of this section at the frequency specified in Table 2, in months (see § 3175.90 of this subpart).

(c) *Routine verification procedures.* (1) Before performing any verification required in this part, the operator must perform a leak test in the manner required under 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 operator must obtain the as-found values of differential and static pressure against a certified pressure device at the following readings in the order listed: Zero (vented to atmosphere), 50 percent of the element range, 100 percent of the element range, 80 percent of the element range, 20 percent of the element range, zero (vented to atmosphere), with 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 operator must also obtain an as-found value at those points;

(ii) If there is not sufficient data on site to determine the points at which the differential and static pens normally operate, the operator must also obtain as-found values at 5 percent of the element range 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 a test thermometer 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 along with a test thermometer in an insulated water bath.

(5) The element undergoing verification must be calibrated according to manufacturer specifications if any of the as-found values determined under paragraphs (c)(3) or (4) of this section are not within the tolerances shown in Table 2–1, when compared to the values applied by the test equipment.

(6) The operator must adjust the time lag between the differential and static pen, if necessary, to be 1/96 of the chart rotation period, measured at the chart hub. For example, the time lag is 15 minutes on a 24-hour test chart and 2 hours on an 8-day test chart.

(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 operator 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 in paragraph (c)(3) or (4) of this section vary by more than the tolerances shown in Table 2–1 when compared with the test-device reading, the element whose readings are outside the applicable tolerances must be replaced and verified 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 under Appendix 2 of this subpart; 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 operator must retain documentation of each verification, as required under § 3170.7(g) of this subpart, and submit it to the BLM upon request. This documentation must include:

(1) The time and date of the verification and the prior verification date;

(2) Primary-device data (meter-tube inside diameter and differential-device size and Beta or area ratio);

(3) The type and location of taps (flange or pipe, upstream or downstream static tap);

(4) Atmospheric pressure used to offset the static-pressure pen, if applicable;

(5) Mechanical recorder data (make, model, and differential pressure, static pressure, and temperature element ranges);

(6) The normal operating points for differential pressure, static pressure, and flowing temperature;

(7) Verification points (as-found and applied) for each element;

(8) Verification points (as-left and applied) for each element, if a calibration was performed;

(9) Names, contact information, and affiliations of the person performing the verification and any witness, if applicable; and

(10) Remarks, if any.

(e) The operator must notify the AO at least 72 hours before conducting the verifications required by this subpart.

(f) 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 Mcf/day, the volumes reported on the OGOR and on royalty reports submitted 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 half way between the date of the last verification and the date of the current verification.

(g) Test equipment used to verify or calibrate elements at an FMP must be certified at least every 2 years. Documentation of the recertification must be on-site during all verifications and must show:

(1) Test equipment serial number, make, and model;

(2) The date on which the recertification took place;

(3) The test equipment measurement range; and

(4) The uncertainty determined or verified as part of the recertification.

§ 3175.93 Integration statements.

An unedited integration statement must be retained and made available to the BLM upon request. The integration statement must contain the following information:

(a) The information required in § 3170.7(g) of this subpart;

(b) The name of the company performing the integration;

(c) The month and year for which the integration statement applies;

(d) Meter-tube inside diameter (inches);

(e) The following primary device information, as applicable:

(i) Orifice bore diameter (inches); or

(ii) Beta or area ratio, discharge coefficient, and other information necessary to calculate the flow rate;

(f) Relative density (specific gravity);

(g) CO_2 content (mole percent);

(h) N_2 content (mole percent);

(i) Heating value calculated under § 3175.125 (Btu/standard cubic feet);

(j) Atmospheric pressure or elevation at the FMP;

(k) Pressure base;

(l) Temperature base;

(m) Static pressure tap location (upstream or downstream);

(n) Chart rotation (hours or days);

(o) Differential pressure bellows range (inches of water);

(p) Static pressure element range (psi); and

(q) For each chart or day integrated:

(i) The time and date on and time and date off;

(ii) Average differential pressure (inches of water);

(iii) Average static pressure;

(iv) Static pressure units of measure (psia or psig);

(v) Average temperature (° F);

(vi) Integrator counts or extension;

(vii) Hours of flow; and

(viii) Volume (Mcf).

§ 3175.94 Volume determination.

(a) 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, calculated under API 14.3.3 (incorporated by reference, see § 3175.31). or AGA Report No. 3 (1985)

β = Beta ratio.

Y = gas expansion factor, calculated under API 14.3.3.5.6 (incorporated by reference, see § 3175.31) or AGA Report No. 3 (1985)

d = orifice diameter, in inches.

Z_b = supercompressibility at base pressure and temperature

G_r = relative density (specific gravity).

Z_f = supercompressibility at flowing pressure and temperature

T_f = average flowing temperature, in degrees Rankine.

(2) For other types of primary devices, the IMV must be calculated using the equations and procedures recommended by the PMT and approved by the BLM, specific to the make, model, size, and area ratio of the primary device being used.

(3) 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 the integration statement 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.

(b) Atmospheric pressure used to convert static pressure in psig to static pressure in psia must be determined under Appendix 2 of this subpart.

§ 3175.100 Electronic gas measurement (secondary and tertiary device).

The following table lists the API standards and BLM requirements that the operator must follow to install and maintain an EGM system on a differential-type primary device. A requirement applies when a column is marked with an "x" or a number.

TABLE 3—STANDARDS FOR ELECTRONIC GAS MEASUREMENT SYSTEMS

Subject	Reference (API standards incorporated by reference, see § 3175.31)	M	L	H	V
EGM commissioning	API 21.1.7.3	n/a	x	x	x
Access and data security	API. 21.1.9	x	x	x	x
No-flow cutoff	API 21.1.4.4.5	x	x	x	x
Manifolds and gauge lines	§ 3175.101(a)	n/a	x	x	x
Display requirements	§ 3175.101(b)	x	x	x	x
On-site information	§ 3175.101(c)	x	x	x	x
Operating within the calibrated limits	§ 3175.101(d)	n/a	x	x	x
Flowing-temperature measurement	§ 3175.101(e)	n/a	x	x	x
Verification after installation or following repair*	§ 3175.102(a)	x	x	x	x
Routine verification frequency, in months*	§ 3175.102(b)	12	6	3	1
Routine verification procedures	§ 3175.102(c)	x	x	x	x
Redundancy verification	§ 3175.102(d)	x	x	x	x
Documentation of verification	§ 3175.102(e)	x	x	x	x
Notification of verification	§ 3175.102(f)	x	x	x	x
Volume correction	§ 3175.102(g)	n/a	x	x	x
Test-equipment certification	§ 3175.102(h)	x	x	x	x
Flow-rate calculation	§ 3175.103(a)	x	x	x	x
Atmospheric pressure	3175.103(b)	x	x	x	x
Volume calculation	§ 3175.103(c)	x	x	x	x
QTR requirements	§ 3175.104(a)	x	x	x	x
Configuration log requirements	§ 3175.104(b)	x	x	x	x
Event log	§ 3175.104(c)	x	x	x	x

M=Marginal-volume FMP; L=Low-volume FMP; H=High-volume FMP; V=Very-high-volume FMP = Immediate assessment for non-compliance under § 3175.150 of this subpart.

§ 3175.101 Installation and operation of electronic gas measurement systems.

(a) Manifolds and gauge lines connecting the pressure taps to the secondary device must:

(1) Have an internal diameter not less than 3⁄8-inch, including ports and valves;

(2) Be constructed of stainless steel;

(3) Be sloped upwards from the pressure taps at a minimum pitch of 1 inch per foot of length;

(4) Have the same internal diameter along their entire length;

(5) Not include any tees except for the static pressure line;

(6) Not be connected to any other devices or more than one differential pressure and static pressure transducer. If the operator is employing redundancy verification, two differential pressure and two static pressure transducers may be connected; and

(7) Be no longer than 6 feet.

(b) Each FMP must include a display which must:

(1) Be readable without the need for data-collection units, laptop computers, a password, or any special equipment;

(2) Be on site and in a location that is accessible to the AO;

(3) Include the units of measure for each required variable;

(4) Display the following variables:

(i) The FMP number or, if an FMP number has not yet been assigned, a unique meter-identification number;

(ii) Software version;

(iii) Current flowing static pressure with units (psia or psig);

(iv) Current differential pressure (inches of water);

(v) Current flowing temperature (° F);

(vi) Current flow rate (Mcf/day or scf/day);

(vii) Previous-day volume (Mcf);

(viii) Previous-day flow time;

(ix) Previous-day average differential pressure (inches of water);

(x) Previous-day average static pressure with units (psia or psig);

(xi) Previous-day average flowing temperature (° F);

(xii) Relative density (specific gravity); and

(xiii) Primary device information such as orifice-bore diameter (inches) or Beta or area ratio and discharge coefficient, as applicable; and

(5) Display items (iii) through (v) in paragraph (b)(4) of this section consecutively.

(c) The following information must be maintained at the FMP in a legible condition, in compliance with § 3170.7(g) of this part, and accessible to the AO at all times:

(1) Elevation of the FMP;

(3) Meter-tube mean inside diameter;

(3) Make, model, and location of approved isolating flow conditioners, if used;

(4) Location of the downstream end of 19-tube-bundle flow straighteners, if used;

(5) For self-contained EGM systems, the make and model number of the system;

(6) For component-type EGM systems, the make and model number of each transducer and the flow computer;

(7) URL and upper calibrated limit for each transducer;

(8) Location of the static pressure tap (upstream or downstream);

(9) Last primary-device inspection date; and

(10) Last secondary device verification date.

(d) The differential pressure, static pressure, and flowing temperature transducers must be operated between the lower and upper calibrated limits of the transducer.

(e) The flowing temperature of the gas must be continuously measured and used in the flow-rate calculations under API 21.1.4 (incorporated by reference, see § 3175.31).

§ 3175.102 Verification and calibration of electronic gas measurement systems.

(a) *Verification after installation or following repair.* (1) Before performing any verification required in this section, the operator must perform a leak test in the manner prescribed in § 3175.92(a)(1) of this subpart.

(2) The operator must verify the points listed in API 21.1.7.3.3 (incorporated by reference, see § 3175.31) 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 determined by API 21.1.8.2.2.2, Equation 24 (incorporated by reference, see § 3175.31), then that transducer must be replaced and retested 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 under Appendix 2 to this subpart or measured by a NIST-certified barometer with a stated accuracy of ±0.05 psi, or better.

(4) Before putting a meter into service, the differential-pressure transducer must be re-zeroed with full working pressure applied to both sides of the transducer.

(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 under the requirements of paragraph (c) of this section at the frequency specified in Table 3, in months (see § 3175.100 of this subpart); or

(2) If redundancy verification under paragraph (d) of this section is used, the differential pressure, static pressure, and temperature transducers must be verified under the requirements of paragraph (d) of this section. In addition, the transducers must be verified under the requirements of paragraph (c) of this section at least annually.

(c) *Routine verification procedures.* Verifications must be performed according to API 21.1.8.2 (incorporated by reference, see § 3175.31), with the following exceptions, additions, and clarifications:

(1) Before performing any verification required under this section, the operator must perform a leak test consistent with § 3175.92(a)(1) of this subpart.

(2) An as-found verification for differential and static pressure must be conducted at the normal operating point of each transducer. The normal operating point is the flow-time linear average taken over the previous day (*i.e.* the value required in § 3175.101(b)(4)(ix) and (x) of this subpart), or a longer period if available at the time of verification.

(3) If either the differential- or static-pressure 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 API 21.1, Annex H, Equation H.1 (incorporated by reference, see § 3175.31).

(5) The verification tolerance for differential and static pressure is defined by API 21.1.8.2.2.2, Equation 24 (incorporated by reference, see § 3175.31). The verification tolerance for temperature is 0.5 degrees F.

(6) All required verification points must be within the verification tolerance before returning the meter to service.

(7) Before returning a meter to service, the differential pressure transducer must be rezeroed with full working pressure applied to both sides of the transducer.

(d) *Redundancy verification procedures.* Redundancy verifications must be performed as required under API 21.1.8.2 (incorporated by reference, see § 3175.31), with the following exceptions, additions, and clarifications:

(1) The operator must identify which set of transducers is used for reporting on the OGOR (the primary transducers) and which set of transducers is used as a check (the check set of transducers);

(2) For every calendar month, the operator must compare the flow-time linear average of differential pressure, static pressure, and temperature readings from the primary transducers with the check transducers;

(3) If for any transducer the difference between the averages exceeds the tolerance defined by the following equation:

$$Tolerance = \sqrt{A_p^2 + A_c^2}$$

where

A_p is the reference accuracy of the primary transducer and

A_c is the reference accuracy of the check transducer,

the operator must verify both the primary and check transducer under paragraph (c) of this section within the first 5 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 the 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.

(e) The operator must retain documentation of each verification for the period required under § 3170.6 of this part, and submit it to the BLM upon request.

(1) For routine verifications, this documentation must include:

(i) The information required in § 3170.7(g) of this part;

(ii) The time and date of the verification and the last verification date;

(iii) Primary device data (meter-tube inside diameter and differential-device size, Beta or area ratio);

(iv) The type and location of taps (flange or pipe, upstream or downstream static tap);

(v) The flow computer make and model;

(vi) The make and model number for each transducer, for component-type EGM systems;

(vii) Transducer data (make, model, differential, static, temperature URL, and upper calibrated limit);

(viii) The normal operating points for differential pressure, static pressure, and flowing temperature;

(ix) Atmospheric pressure;

(x) Verification points (as-found and applied) for each transducer;

(xi) Verification points (as-left and applied) for each transducer, if calibration was performed;

(xii) The differential device inspection date and condition (*e.g.,* clean, sharp edge, or surface condition);

(xiii) Verification equipment make, model, range, accuracy, and last certification date;

(xiv) The name, contact information, and affiliation of the person performing the verification and any witness, if applicable; and

(xv) Remarks, if any.

(2) For redundancy verification checks, this documentation must include;

(i) The information required in § 3170.7(g) of this part;

(ii) The month and year for which the redundancy check applies;

(iii) The makes, models, upper range limits, and upper calibrated limits of the primary set of transducers;

(iv) The makes, models, upper range limits, and upper calibrated limits of the check set of transducers;

(v) The information required in API 21.1, Annex I (incorporated by reference, see § 3175.31);

(vii) The tolerance for differential pressure, static pressure, and temperature as calculated under paragraph (d)(2) of this section; and

(viii) Whether or not each transducer required verification under paragraph (c) of this section.

(f) The operator must notify the AO at least 72 hours before conducting the tests and verifications required by paragraph (c) of this section.

(g) 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 or 2 Mcf/day, whichever is less, the volumes reported on the OGOR and on royalty reports submitted 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 half way between the date of the last verification and the date of the present verification.

(h) *Test equipment requirements.* (1) Test equipment used to verify or calibrate transducers at an FMP must be certified at least every 2 years. Documentation of the certification must be on site and made available to the AO during all verifications and must show:

(i) The test equipment serial number, make, and model;

(ii) The date on which the recertification took place;

(iii) The range of the test equipment; and

(iv) The uncertainty determined or verified as part of the recertification.

(2) Test equipment used to verify or calibrate transducers at an FMP must meet the following accuracy standards:

(i) 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

(ii) It must have a stated accuracy of at least 0.10 percent of the upper calibrated limit of the transducer being verified.

§ 3175.103 Flow rate, volume, and average value calculation.

(a) The flow rate must be calculated as follows:

(1) For flange-tapped orifice plates, the flow rate must be calculated under:

(i) API 14.3.3.4 and API 14.3.3.5 (both incorporated by reference, see § 3175.31); and

(ii) API 14.2 (incorporated by reference, see § 3175.31), for supercompressibility.

(2) For primary devices other than flange-tapped orifice plates, the flow rate must be calculated under the equations and procedures recommended by the PMT and approved by the BLM, specific to the make, model, size, and area ratio of the primary device used.

(b) Atmospheric pressure used to convert static pressure in psig to static pressure in psia must be determined under API 21.1.8.3.3 (incorporated by reference, see § 3175.31).

(c) Hourly and daily gas volumes, average values of the live input variables, flow time, and integral value or average extension as required under § 3175.104 of this subpart must be determined under API 21.1. 4 and API 21.1 Annex B (both incorporated by reference, see § 3175.31).

§ 3175.104 Logs and records.

(a) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited daily and hourly QTRs, which must contain the information identified in API 21.1.5.2 (incorporated by reference, see § 3175.31), with the following additions and clarifications:

(1) The information required in § 3170.7(g) of this part;

(2) The volume, flow time, integral value or average extension, and the average differential pressure, static pressure, and temperature as calculated in § 3175.103(c) of this subpart, reported to at least five significant digits; and

(3) A statement of whether the operator has submitted the integral value or average extension.

(b) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited configuration log which must contain the information specified in API 21.1.5.4 (including the flow computer snapshot report in API 21.1.5.4.2) and API 21.1 Annex G (all three incorporated by reference, see § 3175.31), with the following additions and clarifications:

(1) The information required in § 3170.7(g) of this part;

(2) Software/firmware identifiers under API 21.1.5.3 (incorporated by reference, see § 3175.31);

(3) For marginal-volume FMPs only, the fixed temperature, if not continuously measured (°F); and

(4) The static-pressure tap location (upstream or downstream);

(c) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited event log. The event log must comply with API 21.1.5.5 (incorporated by reference, see § 3175.31), with the following additions and clarifications:

(1) The event log must record all power outages that inhibit the meter's ability to collect and store new data. The event log must indicate the length of the outage; and

(2) The event log must have sufficient capacity and must be retrieved and stored at intervals frequent enough to maintain a continuous record of events as required under § 3170.7 of this part, or the life of the FMP, whichever is shorter.

(d) The operator must retain an alarm log and provide it to the BLM upon request. The alarm log must comply with API 21.1.5.6 (incorporated by reference, see § 3175.31).

§ 3175.110 Gas sampling and analysis.

The following table lists the standards and practices that the operator must follow to obtain a reliable, accurate gas sample for the determination of relative density and heating value. A requirement applies when a column is marked with an ''x'' or a number.

TABLE 4—GAS SAMPLING AND ANALYSIS

Subject	Reference	M	L	H	V
Types of sampling	§ 3175.111(a)	x	x	x	x
Heating requirements	§ 3175.111(b)	x	x	x	x
Samples taken from probes	§ 3175.112(a)	n/a	x	x	x
Location of sample probe	§ 3175.112(b)	n/a	x	x	x
Sample probe design and type	§ 3175.112(c)	n/a	x	x	x
Sample tubing	§ 3175.112(d)	n/a	x	x	x
Spot sample while flowing	§ 3175.113(a)	x	x	x	x
Notification of spot samples	§ 3175.113(b)	x	x	x	x
Sample cylinder requirements	§ 3175.113(c)	x	x	x	x
Spot sampling using portable GCs	§ 3175.113(d)	x	x	x	x
Allowable methods of spot sampling	§ 3175.114	x	x	x	x
Spot sampling frequency, low and marginal FMPs (in months)*	§ 3175.115(a)	12	6	n/a	n/a
Initial spot sampling frequency, high and very-high FMPs (in months)*	§ 3175.115(a)	n/a	n/a	3	1
Adjustment of spot sampling frequencies, high and very-high FMPs	§ 3175.115(b)	n/a	n/a	x	x
Maximum time between samples	§ 3175.115(c)	x	x	x	x
Installation of composite sampler or on-line GC	§ 3175.115(d)	x	x	x	x
Removal of composite sampler or on-line GC	§ 3175.115(e)	x	x	x	x
Composite sampling methods	§ 3175.116	x	x	x	x
On-line gas chromatographs	§ 3175.117	x	x	x	x
Gas chromatograph requirements	§ 3175.118	x	x	x	x
Minimum components to analyze	§ 3175.119(a)	x	x	x	x
Extended analysis	§ 3175.119(b)	n/a	n/a	x	x
Gas analysis report requirements	§ 3175.120	x	x	x	x
Effective date of spot and composite samples	§ 3175.121	x	x	x	x

M = Marginal-volume FMP; L = Low-volume FMP; H = High-volume FMP; V = Very-high-volume FMP, * = Immediate assessment for non-compliance under § 3175.150 of this subpart

§ 3175.111 General sampling requirements.

(a) Samples must be taken by one of the following methods:

(1) Spot sampling under §§ 3175.113 to 3175.115 of this subpart;

(2) Flow-proportional composite sampling under § 3175.116 of this subpart; or

(3) On-line gas chromatograph under § 3175.117 of this subpart.

(b) The temperature of all gas sampling components must be maintained at least 30 °F above the hydrocarbon dew point of the gas at all times during the sampling process.

§ 3175.112 Sampling probe and tubing.

(a) All gas samples must be taken from a sample probe that complies with the requirements of paragraphs (b) and (c) of this section.

(b) *Location of sample probe.* (1) The sample probe must be located downstream of the primary device between 1.0 and 2.0 times dimension ''DL'' (Downstream Length) from API 14.3.2 (incorporated by reference, see § 3175.31), Table 2.7 or 2.8, as appropriate, and must be the first obstruction downstream of the primary device.

(2) The sample probe must be exposed to the same ambient conditions as the primary device. For example, if the primary device is located in a heated meter house, the sample probe must also be located in the same heated meter house.

(c) *Sample probe design and type.* (1) Sample probes must be constructed 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 long enough to place the collection end of the probe in the center one third of the pipe cross-section.

(4) The use of membranes, screens, or filters at any point in the sample probe is prohibited.

(d) Sample tubing connecting the sample probe to the sample container or analyzer must be constructed of stainless steel or nylon 11.

§ 3175.113 Spot samples—general requirements.

(a) If an FMP is not flowing at the time that a sample is due, a sample must be taken within 5 days of when flow is re-initiated. Documentation of the non-flowing status of the FMP must be entered into GARVS as required under § 3175.120(f) of this subpart.

(b) The operator must notify the AO at least 72 hours before obtaining a spot sample as required by this subpart.

(c) *Sample cylinder requirements.* Sample cylinders must:

(1) Be constructed of stainless steel;

(2) Have a minimum capacity of 300 cubic centimeters;

(3) Be cleaned before sampling under GPA 2166–05, Appendix A (incorporated by reference, see § 3175.31), or an equivalent method (of which cleaning the operator must maintain documentation); and

(4) Be physically sealed in a manner that prevents opening the sample cylinder without breaking the seal before sampling.

(d) *Spot sampling using portable gas chromatographs.* (1) Sampling separators, if used, must:

(i) Be constructed of stainless steel;

(ii) Be cleaned under GPA 2166–05, Appendix A (incorporated by reference, see § 3175.31), or an equivalent method, prior to sampling (of which cleaning the operator must maintain documentation); and

(iii) Be operated under GPA 2166–05, Appendix B.3 (incorporated by reference, see § 3175.31).

(2) Filters at the inlet of the GC must be cleaned or replaced before sampling.

(3) The sample port and inlet to the sample line must be purged before sealing the connection between them.

(4) The portable GC must be designed, operated, and calibrated under § 3175.118 of this subpart.

(5) Portable GCs may not be used when the flowing pressure of the gas is less than 15 psig.

§ 3175.114 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 GPA 2166–05, Section 9.1 (incorporated by reference, see § 3175.31);

(2) *Helium ''pop'' method.* Samples taken using this method must comply with GPA 2166–05, Section 9.5 (incorporated by reference, see § 3175.31). The operator must maintain documentation demonstrating that the cylinder was evacuated and pre-charged before sampling and make it available to the AO upon request;

(3) *Floating piston cylinder method.* Samples taken using this method must comply with GPA 2166–05, Sections 9.7.1 to 9.7.3 (incorporated by reference, see § 3175.31). The operator must maintain documentation of the seal material and type of lubricant used and make it available to the AO upon request;

(4) *Portable gas chromatograph.* Samples taken using this method must comply with § 3175.118 of this subpart.

(5) Other methods approved by the BLM (through the PMT) and posted at *www.blm.gov.*

(b) If the operator uses either a purging-fill and empty method or a helium ''pop'' method, and if the flowing pressure at the sample port is less than or equal to 15 psig, the operator may also employ a vacuum-gathering system. Samples taken using a vacuum- gathering system must comply with API 14.1.12.10 (incorporated by reference, see § 3175.31), and the samples must be obtained from the discharge of the vacuum pump.

§ 3175.115 Spot samples—frequency.

(a) Unless otherwise required under paragraph (b) of this section, spot samples for all FMPs must be taken and analyzed at the frequency (once during every period, stated in months) prescribed in Table 4 (see § 3175.110).

(b) The BLM may change the required sampling frequency for high-volume and very-high-volume FMPs if the BLM determines that the sampling frequency required in Table 4 is not sufficient to achieve the heating value certainty levels required in § 3175.30(b) of this subpart.

(1) The BLM will calculate the new sampling frequency needed to achieve the heating value certainty levels required in § 3175.30(b) of this subpart. The BLM will base the sampling frequency calculation on the statistical variability of previously reported heating values. The BLM will notify the operator of the new sampling frequency.

(2) The new sampling frequency will remain in effect until the variability of previous heating values justifies a different frequency.

(3) The new sampling frequency will not be more frequent than once per week nor less frequent than once every 6 months.

(4) The BLM may require the installation of a composite sampling system or on-line GC if the heating value certainty levels in 3175.30(b) of this subpart cannot be achieved through spot sampling.

(c) The time between any two samples must not exceed the timeframes shown in Table 5.

TABLE 5—MAXIMUM TIME BETWEEN SAMPLES

If the required sampling frequency is once during every:	Then the maximum time between samples (in days) is:
Week	9
2 weeks	18
Month	45
2 months	75
3 months	105
6 months	195
12 months	380

(d) If a composite sampling system or an on-line GC is installed under §§ 3175.116 or 3175.117 of this subpart, either on the operator's own initiative or in response to a BLM order to change the sampling frequency for a high-volume or very-high-volume FMP under paragraph (b) of this section, it must be installed and operational no more than 30 days after the due date of the next sample.

(e) The required sampling frequency for an FMP at which a composite sampling system or an on-line gas chromatograph is removed from service is prescribed in paragraph (a).

§ 3175.116 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.

(d) The composite sampling system must meet the heating value uncertainty requirements of § 3175.30(b) of this subpart.

§ 3175.117 On-line gas chromatographs.

(a) On-line GCs must be installed, operated, and maintained under GPA 2166–05, Appendix D (incorporated by reference, see § 3175.31), and the manufacturer's specifications, instructions, and recommendations.

(b) The on-line GC must meet the uncertainty requirements for heating values required in § 3175.30(b) of this subpart.

(c) Upon request, the operator must submit to the AO the manufacturer's specifications and installation and operational recommendations.

(d) The GC must comply with the verification and calibration requirements of § 3175.118 of this subpart. The results of all verifications must be submitted to the AO upon request.

§ 3175.118 Gas chromatograph requirements.

(a) All GCs must be designed, installed, operated, and calibrated under GPA 2261–00 (incorporated by reference, see § 3175.31).

(b) Samples must be analyzed until three consecutive runs are within the repeatability standards listed in GPA 2261–00, Section 9 (incorporated by reference, see § 3175.31), and the unnormalized sum of the mole percent of all gases analyzed is between 99 and 101 percent.

(c) GCs must be verified under GPA 2261–00 (incorporated by reference, see § 3175.31), Sections 4 and 5, at the following frequencies:

(1) For portable GCs that are used for spot sampling, not more than 24 hours before sampling at an FMP; or

(2) For laboratory and on-line GCs, not less than once every 7 days.

(d) The gas used for verification must not be the same gas used for calibration.

(e) If the composition of the sample as determined by the GC varies from the composition of the calibration gas by more than the repeatability values listed in GPA 2261–00, Section 9 (incorporated by reference, see § 3175.31), the GC must be calibrated under GPA 2261–00, Section 5 (incorporated by reference, see § 3175.31).

(f) If the GC is calibrated, it must be re-verified under paragraphs (d) and (e) of this section.

(g) A GC may not be used to analyze any sample from an FMP until the verification meets the standards of paragraph (e) of this section.

(h) All gases used for verification and calibration must meet the standards of GPA 2198–03 (incorporated by reference, see § 3175.31).

(i) The operator must retain documentation of the verifications for the period required under § 3170.6 of this part, and make it available to the BLM upon request. For portable GCs used for spot sampling, documentation of the last verification must be on site at the time of sampling. 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 GC;

(5) The mole percent of each component in the gas used for verification;

(6) The difference between the mole percents determined in paragraphs (i)(4) and (i)(5) of this section, expressed in relative percent;

(7) Documentation that the gas used for verification meets the requirements of GPA 2198–03 (incorporated by reference, see § 3175.31), including a unique identification number of the calibration gas used and the name of the supplier of the calibration gas;

(8) The time and date the verification was performed; and

(9) The name and affiliation of the person performing the verification.

§ 3175.119 Components to analyze.

(a) The gas must be analyzed for the following components:

(1) Methane;

(2) Ethane;

(3) Propane;

(4) Iso Butane;

(5) Normal Butane;

(6) Pentanes;

(7) Hexanes + (C_6+);

(8) Carbon dioxide; and

(9) Nitrogen.

(b) For high-volume and very high-volume FMPs, if the concentration of C_6+ exceeds 0.25 mole percent, the following gas components must also be analyzed:

(1) Hexane;

(2) Heptane;

(3) Octane; and

(4) Nonane+.

§ 3175.120 Gas analysis report requirements.

(a) The gas analysis report must contain the following information:

(1) The information required in § 3170.7(g) of this part;

(2) The date and time that the sample for spot samples was taken or, for composite samples, the date the cylinder was installed and the date the cylinder was removed;

(3) The date and time of the analysis;

(4) For spot samples, the effective date, if other than the date of sampling;

(5) For composite samples, the effective start and end date;

(6) The name of the laboratory where the analysis was performed;

(7) The device used for analysis (*i.e.,* GC, calorimeter, or mass spectrometer);

(8) The make and model of analyzer;

(9) The date of last calibration or verification of the analyzer;

(10) The flowing temperature at the time of sampling;

(11) The flowing pressure at the time of sampling, including units of measure (psia or psig);

(12) The flow rate at the time of the sampling;

(13) The ambient air temperature at the time the sample was taken;

(14) Whether or not heat trace or any other method of heating was used;

(15) The type of sample (*i.e.,* spot-cylinder, spot-portable GC, composite);

(16) The sampling method if spot-cylinder (*e.g.,* fill and empty, helium pop);

(17) A list of the components of the gas tested;

(18) The un-normalized mole percentages of the components tested, including a summation of those mole percents;

(19) The normalized mole percent of each component tested, including a summation of those mole percents;

(20) The ideal heating value (Btu/scf);

(21) The real heating value (Btu/scf), dry basis;

(22) The pressure base and temperature base;

(23) The relative density; and

(24) The name of the company obtaining the gas sample.

(b) Components that are listed on the analysis report, but not tested, must be annotated as such.

(c) The heating value and relative density must be calculated under API 14.5 (incorporated by reference, see § 3175.31).

(d) The base supercompressibility must be calculated under API 14.2 (incorporated by reference, see § 3175.31).

(e) The operator must submit all gas analysis reports to the BLM within 5 days of the due date for the sample as specified in § 3175.115 of this subpart.

(f) Unless a variance is granted, the operator must submit all gas analysis reports and other required related information electronically through the GARVS. The BLM will grant a variance only in cases where the operator demonstrates that it is a small business, as defined by the U.S. Small Business Administration, and does not have access to the Internet.

§ 3175.121 Effective date of a spot or composite gas sample.

(a) Unless otherwise specified on the gas analysis report, the effective date of a spot sample is the date on which the sample was taken.

(b) The effective date of a spot gas sample may be no later than the first day of the production month following the operator's receipt of the laboratory analysis of the sample.

(c) The effective date of a composite sample is the date when the sample cylinder was installed.

§ 3175.125 Calculation of heating value and volume

(a) The heating value of the gas sampled must be calculated as follows:

(1) Gross heating value is defined by API 14.5.3.7 (incorporated by reference, see § 3175.31) and must be calculated under API 14.5.7.1 (incorporated by reference, see § 3175.31); and

(2) Real heating value must be calculated by dividing the gross heating value of the gas calculated under paragraph (a)(1) by the compressibility factor of the gas at 14.73 psia and 60 °F.

(b) *Average heating value determination.* (1) If a lease, unit PA, or CA has more than one FMP, the average heating value for the lease, unit PA, or CA, for a reporting month must be the volume-weighted average of heating values, calculated as follows:

$$\overline{HV} = \frac{\sum_{i=1}^{i=n}\left(HV_i \times V_i\right)}{\sum_{i=1}^{i=n} V_i}$$

Where:

HV= the average heating value for the lease, unit PA, or CA, for the reporting month, in Btu/scf

HV_i = the heating value for FMP_i, during the reporting month (see § 3175.120(b)(2) of this subpart if an FMP has multiple heating values during the reporting month), in Btu/scf

V_i = the volume measured by FMPi, during the reporting month, in Btu/scf

Subscript i represents each FMP for the lease, unit PA, or CA

n = the number of FMPs for the lease, unit PA, or CA.

(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:

$$HV_i = \frac{\sum_{j=1}^{j=m}\left(HV_{i,j} \times V_{i,j}\right)}{\sum_{j=1}^{j=m} V_{i,j}}$$

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

Subscript i represents each FMP for the lease, unit PA, or CA

Subscript 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) The volume must be determined under §§ 3175.94 (mechanical recorders) or 3175.103(c) (EGM systems) of this subpart.

§ 3175.126 Reporting of heating value and volume.

(a) 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 on the OGOR 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 and reported on the gas analysis report. The heating value may not be reported on the basis of an assumed water vapor content. Acceptable methods of measuring water vapor are:

(i) Chilled mirror;

(ii) Laser detectors; and

(iii) Other methods approved by the BLM;

(2) Adjusted to a pressure of 14.73 psia and a temperature of 60 °F; and

(3) For samples analyzed under § 3175.119(a) of this subpart, and notwithstanding any provision of a contract between the operator and a purchaser or transporter, the composition of hexane+ is deemed to be:

(i) 60 percent n-hexane;

(ii) 30 percent n-heptane; and

(iii) 10 percent n-octane;

(b) The volume for royalty purposes must be reported on the OGOR in units of Mcf as follows:

(1) The volumes must not be adjusted for water vapor content or any other factors that are not included in the calculations required in §§ 3175.94 or 3175.103 of this subpart; 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 volume or heating value.* (1) If for any reason there are measurement errors stemming from an equipment malfunction which results in discrepancies to the calculated volume or heating value of the gas, the volume or heating value reported during the period in which the volume or heating value error subsisted must be estimated as follows:

(i) For volume errors, during the time the measurement equipment was malfunctioning or out of service, use the average of the flow rate before the time the error occurred and the flow rate after the error was corrected; and

(ii) For heating value errors, use the average of the heating values determined from five samples from the same FMP taken closest in time to the period in which the error subsisted, excluding the heating value(s) from the sample(s) known to be in error. If fewer than five heating values have been obtained, use the average of the most recent heating values that are known not to be in error.

(2) All edits made to the data before the submission of the OGOR must be documented and include verifiable justifications for the edits made. This documentation must be maintained under § 3170.7 of this part and must be submitted to the BLM upon request.

(3) All values on daily and hourly QTRs that have been changed or edited must be clearly identified and must be cross referenced to the justification required in paragraph (c)(2) of this section.

(4) The volumes reported on the OGOR 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 half way between the date of the previous verification and the most recent verification date.

§ 3175.130 Transducer testing protocol.

The BLM will approve a particular make, model, and range of differential-pressure, static-pressure, or temperature transducer for use in an EGM system only if the testing performed on the transducer met all of the standards and requirements stated in §§ 3175.131 through 3175.135 of this subpart.

§ 3175.131 General requirements for transducer testing.

(a) *Qualified test facilities.* (1) All testing must be performed by an independent test facility not affiliated with the manufacturer.

(2) All equipment used for testing must be traceable to the NIST and have a current certification proving its traceability.

(b) *Number and selection of transducers tested.* (1) A minimum of five transducers of the same make, model, and URL, selected at random from the stock used to supply normal field operations, must be type-tested.

(2) The serial number of each transducer selected must be documented. The date, location, and batch identifier, if applicable, of manufacture is ascertainable from the serial number.

(c) *Test conditions—general.* The electrical supply must meet the following minimum tolerances:

(1) Rated voltage: ±1 percent uncertainty;

(2) Rated frequency: ±1 percent uncertainty;

(3) Alternating current harmonic distortion: Less than 5 percent; and

(4) Direct current ripple: Less than 0.10 percent uncertainty.

(d) The input and output (if the output is analog) of each transducer must be measured with equipment that has a published reference uncertainty less than or equal to 25 percent of the published reference uncertainty of the transducer under test across the measurement range common to both the transducer under test and the test instrument. Reference uncertainty for both the test instrument and the transducer under test must be expressed in the units the transducer measures to determine acceptable uncertainty. For example, if the transducer under test has a published reference uncertainty of ±0.05 percent of span, and a span of 0 to 500 psia, then this transducer has a reference accuracy of ±0.25 psia (0.05 percent of 500 psia). To meet the requirements of this paragraph, the test instrument in this example must have an uncertainty of ±0.0625 psia, or less (25 percent of ±0.25 psia).

(e) If the manufacturer's performance specifications for the transducer under test include corrections made by an external device (such as linearization), then the external device must be tested along with the transducer and be connected to the transducer in the same way as in normal field operations.

(f) If the manufacturer specifies the extent to which the measurement range of the transducer under test may be adjusted downward (*i.e.,* spanned down), then each test required in §§ 3175.132 and 3175.133 of this subpart must be carried out at least at both the URL and the minimum upper calibrated limit specified by the manufacturer. For upper calibrated limits between the maximum and the minimum span that are not tested, the BLM will use the greater of the uncertainties measured at the maximum and minimum spans in determining compliance with the requirements of § 3175.30(a) of this subpart.

(g) After initial calibration, no calibration adjustments to the transducer may be made until all required tests in §§ 3175.132 and 3175.133 of this subpart are completed.

(h) For all of the testing required in §§ 3175.132 and 3175.133 of this subpart, the term ''tested for accuracy'' means a comparison between the output of the transducer under test and the test equipment taken as follows:

(1) The following values must be tested in the order shown, expressed as a percent of the transducer span:

(i) (Ascending values) 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, and 100; and

(ii) (descending values) 100, 90, 80, 70, 60, 50, 40, 30, 20, 10, and 0.

(2) If the device under test is an absolute pressure transducer, the ''0'' values listed in paragraph (h)(1)(i) and (ii) of this section must be replaced with ''atmospheric pressure at the test facility;''

(3) Input approaching each required test point must be applied asymptotically without overshooting the test point;

(4) The comparison of the transducer and the test equipment measurements must be recorded at each required point; and

(5) For static pressure transducers, the following test point must be included for all tests:

(i) For gauge pressure transducers, a gauge pressure of −5 psig; and

(ii) For absolute pressure transducers, an absolute pressure of 5 psia.

§ 3175.132 Testing of reference accuracy.

(a) The following reference test conditions must be maintained for the duration of the testing:

(1) Ambient air temperature must be between 59 °F and 77 °F and must not vary over the duration of the test by more than ±2 °F;

(2) Relative humidity must be between 45 percent and 75 percent and must not vary over the duration of the test by more than ±5 percent;

(3) Atmospheric pressure must be between 12.46 psi and 15.36 psi and must not vary over the duration of the test by more than ±0.2 psi;

(4) The transducer must be isolated from any externally induced vibrations;

(5) The transducer must be mounted according to the manufacturer's specifications in the same manner as it would be mounted in normal field operations;

(6) The transducer must be isolated from any external electromagnetic fields; and

(7) For reference accuracy testing of differential-pressure transducers, the downstream side of the transducer must be vented to the atmosphere.

(b) Before reference testing begins, the following pre-conditioning steps must be followed:

(1) After power is applied to the transducer, it must be allowed to stabilize for at least 30 minutes before applying any input pressure or temperature;

(2) The transducer must be exercised by applying three full-range traverses in each direction; and

(3) The transducer must be calibrated according to manufacturer specifications if a calibration is required or recommended by the manufacturer.

(c) Immediately following preconditioning, the transducer must then be tested at least three times for accuracy under § 3175.131(h) of this subpart. The results of these tests must be used to determine the transducer's reference accuracy under § 3175.135 of this subpart.

§ 3175.133 Testing of influence effects.

(a) *General requirements.* (1) Reference conditions (see § 3175.132 of this subpart), with the exception of the influence effect being tested under this section, must be maintained for the duration of these tests.

(2) After completing the required tests for each influence effect under this section, the transducer under test must be returned to reference conditions and tested for accuracy under § 3175.132 of this subpart.

(b) *Ambient temperature.* (1) The transducer's accuracy must be tested at the following temperatures (°F): +68, +104, +140, +68, 0, −4, −40, +68.

(2) The ambient temperature must be held to ±4 °F from each required temperature during the accuracy test at each point.

(3) The rate of temperature change between tests must not exceed 2 °F per minute.

(4) The transducer must be allowed to stabilize at each test temperature for at least 1 hour.

(5) For each required temperature test point listed in this paragraph, the transducer must be tested for accuracy under § 3175.131(h) of this subpart.

(c) *Static pressure effects (differential-pressure transducers only).* (1) For single-variable transducers, the following pressures must be applied equally to both sides of the transducer, expressed in percent of maximum rated working pressure: 0, 50, 100, 75, 25, 0.

(2) For multivariable transducers, the following pressures must be applied equally to both sides of the transducer, expressed in percent of the URL of the static-pressure transducer: 0, 50, 100, 75, 25, 0.

(3) For each point required in paragraphs (c)(1) and (2) of this section, the transducer must be tested for accuracy under § 3175.131(h) of this subpart.

(d) *Mounting position effects.* The transducer must be tested for accuracy at four different orientations under § 3175.131(h) of this subpart as follows:

(1) At an angle of −10° from a vertical plane;

(2) At an angle of +10° from a vertical plane;

(3) At an angle of −10° from a vertical plane perpendicular to the original plane; and

(4) At an angle of +10° from a vertical plane perpendicular to the original plane.

(e) *Over-range effects.* (1) A pressure of 150 percent of the URL, or to the maximum rated working pressure of the transducer, whichever is less, must be applied for at least one minute.

(2) After removing the applied pressure, the transducer must be tested for accuracy under § 3175.131(h) of this subpart.

(3) No more than 5 minutes must be allowed between performing the procedures described in paragraphs (e)(1) and (e)(2) of this section.

(f) *Vibration effects.* (1) An initial resonance test must be conducted by applying the following test vibrations to the transducer along each of the three major axes of the transducer while measuring the output of the transducer with no pressure applied:

(i) The amplitude of the applied test frequency must be at least 0.35mm below 60 Hertz (Hz) and 49 meter per second squared (m/s^2) above 60 Hz; and

(ii) The applied frequency must be swept from 10 Hz to 2,000 Hz at a rate not greater than 0.5 octaves per minute.

(2) After the initial resonance search, an endurance conditioning test must be conducted as follows:

(i) 20 frequency sweeps from 10 Hz to 2,000 Hz to 10 Hz must be applied to the transducer at a rate of one octave per minute, repeated for each of the 3 major axes; and

(ii) The measurement of the transducer's output during this test is unnecessary.

(3) A final resonance test must be conducted under paragraph (f)(1) of this section.

(g) *Long-term stability.* (1) Long-term stability must be established through six consecutive testing cycles, each lasting 4 weeks, and each cycle consisting of the following combination of temperature and input conditions:

Week	Input (%) of span	Temperature (°F)
1	0	−22
2	30	+38
3	60	+68
4	60	+122

(2) At the end of each cycle, the transmitter must be brought back to the same reference conditions used to determine the reference accuracy and allowed to stabilize for at least 3 hours. The transmitter must then be tested for accuracy under § 3175.131(h) of this subpart.

§ 3175.134 Transducer test reporting.

(a) Each test required by §§ 3175.131 through 3175.133 of this subpart must be fully documented by the test facility performing the tests. The report must indicate the results for each required test and include all data points recorded.

(b) The report must be submitted to the AO. If the PMT determines that all testing was completed as required by §§ 3175.131 through 3175.133 of this subpart, it will make a recommendation that the BLM post the transducer make, model, and range, along with the reference uncertainty, influence effects, and any operating restrictions to the BLM's Web site (*www.blm.gov*) as an approved device.

§ 3175.135 Uncertainty determination.

(a) Reference uncertainty calculations for each transducer of a given make, model, URL, and turndown must be determined as follows (the result for each transducer is denoted by the subscript i):

(1) *Maximum error (E_i).* The maximum error for each transducer is the maximum difference between any input value from the test device and the corresponding output from the transducer under test for any required test point, and must be expressed in percent of transducer span.

(2) *Hysteresis (H_i).* The testing required in § 3175.132 of this subpart requires at least three pairs of tests using both ascending test points (low to high) and descending test points (high to low) of the same value. Hysteresis is the maximum difference between the ascending value and the descending value for any single input test value of a test pair. Hysteresis must be expressed in percent of span.

(3) *Repeatability (R_i).* The testing required under § 3175.132 of this subpart requires at least three pairs of tests using both ascending test points (low to high) and descending test points (high to low) of the same value. Repeatability is the maximum difference between the value of any of the three ascending test points for a given input value or of the three descending test points for a given value. Repeatability must be expressed in percent of span.

(b) *Reference uncertainty of a transducer.* The reference uncertainty of each transducer of a given make, model, URL, and turndown ($U_{r,i}$) must be determined as follows:

$$U_{r,i} = \sqrt{E_i^2 + H_i^2 + R_i^2}$$

Where E_i, H_i, and R_i, are described in paragraph 3175.134(a) of this section. Reference uncertainty is expressed in percent of span.

(c) Reference uncertainty for the make, model, URL, and turndown of a transducer (U_r) must be determined as follows:

$U_r = \sigma \times t_{dist}$

where:

σ = the standard deviation of the reference uncertainties determined for each transducer ($U_{r,i}$)

t_{dist} = the "t-distribution" constant as a function of degrees of freedom (n-1) and at a 95 percent confidence level, where n = the number of transducers of a specific make, model, URL, and turndown tested (minimum of 5)

(d) *Influence effects.* The uncertainty from each influence effect required to be tested under § 3175.133 of this subpart must be determined as follows:

(1) *Zero-based errors of each transducer.* Zero-based errors from each influence test must be determined as follows:

$$E_{zero,n,i} = \frac{\Delta Z_{n,i}}{span \times M_n} \times 100$$

Where:

subscript i represents the results for each transducer tested of a given make, model, URL, and turndown

subscript n represents the results for each influence effect test required under § 3175.133 of this subpart

$E_{zero,n,i}$ = Zero-based error for influence effect n, for transducer i, in percent of span per increment of influence effect

M_n = the magnitude of influence effect n (*e.g.,* 1,000 psi for static pressure effects, 50 °F for ambient temperature effects)

and:

$\Delta Z_{n,i} = Z_{n,i} - Z_{ref,i}$

where:

$Z_{n,i}$ = the average output from transducer i with zero input from the test device, during the testing of influence effect n

$Z_{ref,i}$ = the average output from transducer i with zero input from the test device, during reference testing.

(2) *Span-based errors of each transducer.* Span-based errors from each influence effect must be determined as follows:

$$E_{span,n,i} = \left(\frac{S_{n,i} - \Delta Z_{n,i}}{span} - 1 \right) \times \frac{100}{M_n}$$

where:

$E_{span,n,i}$ = Span-based error for influence effect n, for transducer i, in percent of reading per increment of influence effect

$S_{n,i}$ = the average output from transducer i, with full span applied from the test device, during the testing for influence effect n.

(3) Zero- and span-based errors due to influence effects for a make, model, URL, and turndown of a transducer must be determined as follows:

$E_{z,n} = \sigma\ E_{z,n}\ x\ t_{dist}$

$E_{s,n} = \sigma\ E_{s,n}\ x\ t_{dist}$

where:

$E_{z,n}$ = the zero-based error for a make, model, URL, and turndown of transducer, for influence effect n, in percent of span per unit of magnitude for the influence effect

$E_{s,n}$ = the span-based error for a make, model, URL, and turndown of transducer, for influence effect n, in percent of reading per unit of magnitude for the influence effect

$\sigma_{z,n}$ = the standard deviation of the zero-based differences from the influence effect tests under § 3175.133 of this subpart and the reference uncertainty tests, in percent

$\sigma_{s,n}$ = the standard deviation of the span-based differences from the influence effect tests under § 3175.133 of this subpart and the reference uncertainty tests, in percent

t_{dist} = the ''t-distribution'' constant as a function of degrees of freedom (n-1) and at a 95 percent confidence level, where n = the number of transducers of a specific make, model, URL, and turndown tested (minimum of 5).

§ 3175.140 Flow-computer software testing.

The BLM will approve a particular version of flow-computer software for use in an EGM system only if the testing performed on the software meets all of the standards and requirements in §§ 3175.141 through 3175.144 of this subpart. Type-testing is required for each software version that affects the calculation of flow rate, volume, heating value, live input variable averaging, flow time, or the integral value.

§ 3175.141 General requirements for flow-computer software testing.

(a) *Qualified test facilities.* All testing must be performed by an independent test facility not affiliated with the manufacturer.

(b) *Selection of flow-computer software to be tested.* (1) Each software version tested must be identical to the software version installed at FMPs for normal field operations.

(2) Each software version must have a unique identifier.

(c) *Testing method.* Input variables may be either:

(1) Applied directly to the hardware registers; or

(2) Applied physically to a transducer. If input variables are applied physically to a transducer, the values received by the hardware registers from the transducer must be recorded.

(d) *Pass-fail criteria.* (1) For each test listed in §§ 3175.142 and 3175.143 of this subpart, the value(s) required to be calculated by the software version under test must be compared to the value(s) calculated by BLM-approved reference software, using the same digital input for both.

(2) The software under test may be used at an FMP only if the difference between all values calculated by the software version under test and the reference software is less than 50 parts per million (0.005 percent) and the results of the tests required in §§ 3175.142 and 3175.143 of this subpart are satisfactory to the PMT. If the test results are satisfactory, the BLM will identify the software version tested as acceptable for use on its Web site at *www.blm.gov.*

§ 3175.142 Required static tests.

(a) *Instantaneous flow rate.* The instantaneous flow rates must meet the criteria in § 3175.141(d) of this subpart for each test identified in Table 6, using the gas compositions identified in Table 7, as prescribed in Table 6.

TABLE 6—REQUIRED INPUTS FOR STATIC TESTING

Test	Pipe inside diameter (inches)	Orifice diameter (inches)	Differential pressure (inches of water)	Static pressure (psia)	Flowing temperature (F)	Composition (see Table 7 of this section)	Static Tap location
1	2.067	0.500	1	15	40	1	Up.
2		1.500	800	140	80	2	Down.
3	6.065	1.000	100	1000	−40	1	Up.
4		4.000	50	500	150	1	Down.
5	4.026	1.000	100	1000	−40	2	Down.
6		3.000	50	500	150	2	Up.

TABLE 7—REQUIRED COMPOSITIONS FOR STATIC TESTING

Component	Composition (mole percent)	
	Composition 1	Composition 2
Methane	92.0000	76.0000
Ethane	3.3000	8.3000
Propane	1.5000	3.6000
i-Butane	0.4900	0.9000
n-Butane	0.3600	1.5000
i-Pentane	0.4000	1.0000
n-Pentane	0.3000	0.5000
n-Hexane	0.3000	0.8000
n-Heptane	0.2000	0.3000
n-Octane	0.1000	0.2000

TABLE 7—REQUIRED COMPOSITIONS FOR STATIC TESTING—Continued

Component	Composition (mole percent)	
	Composition 1	Composition 2
n-Nonane	0.0500	0.1000
Carbon dioxide	0.8000	5.3000
Nitrogen	0.2000	1.4000
Helium	0.0000	0.0500
Oxygen	0.0000	0.0300
Hydrogen sulfide	0.0000	0.0200

(b) *Sums and averages.* (1) Fixed input values from test 2 in Table 6 must be applied for a period of at least 24 hours.

(2) At the conclusion of the 24-hour period, the following hourly and daily values must meet the criteria in § 3175.141(d) of this subpart:

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(c) *Other tests.* The following additional tests must be performed on the flow computer software:

(1) Each parameter of the configuration log must be changed to ensure the event log properly records the changes according to the variables listed in § 3175.104(c) of this subpart;

(2) Inputs simulating a 15 percent and 150 percent over-range of the differential and static pressure transducers must be entered to verify that the over-range condition triggered an alarm or an entry in the event log; and

(3) The power to the flow computer must be shut off for at least 1 hour and then restored to verify that the power outage and time of outage was recorded in the event log or indicated on the quantity transaction log.

§ 3175.143 Required dynamic tests.

(a) *Square wave test.* The pressures and temperatures must be applied to the software revision under test for a duration of at least 60 minutes as follows:

(1) *Differential pressure:* The differential pressure must be cycled from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the upper calibrated limit of the differential pressure transducer. The cycle must approximate a square wave pattern with a period of 60 seconds and the maximum and minimum values must be the same for each cycle;

(2) *Static pressure:* The static pressure must be cycled between approximately 20 percent and approximately 80 percent of the upper calibrated limit of the static pressure transducer in a square wave pattern identical to the cycling pattern used for the differential pressure. The maximum and minimum values must be the same for each cycle;

(3) *Temperature:* The temperature must be cycled between approximately 20 °F and approximately 100 °F in a square wave pattern identical to the cycling pattern used for the differential pressure. The maximum and minimum values must be the same for each cycle; and

(4) At the conclusion of the 1-hour period, the following hourly values must meet the criteria in § 3175.141(d) of this subpart:

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(b) *Sawtooth test.* The pressures and temperatures must be applied to the software revision under test for a duration of 24 hours as follows:

(1) *Differential pressure:* The differential pressure must be cycled from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the maximum value of differential pressure for which the flow computer is designed. The cycle must approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour. The no-flow period between cycles must last approximately 10 percent of the cycle period;

(2) *Static pressure:* The static pressure must be cycled between approximately 20 percent and approximately 80 percent of the maximum value of static pressure for which the flow computer is designed. The cycle must approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour;

(3) *Temperature:* The temperature must be cycled between approximately 20 °F and approximately 100 °F. The cycle should approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour; and

(4) At the conclusion of the 24-hour period, the following hourly and daily values must meet the criteria in § 3175.141(d) of this subpart:

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(c) *Random test.* The pressures and temperatures must be applied to the software revision under test for a duration of 24 hours as follows:

(1) *Differential pressure:* Differential pressure random values must range from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the upper calibrated limit of the differential pressure transducer. The no-flow period between cycles must last for approximately 10 percent of the test period;

(2) *Static pressure:* Static pressure random values must range from a low value of approximately 20 percent of the upper calibrated limit of the static-pressure transducer, to a high value of approximately 80 percent of the upper calibrated limit of the static-pressure transducer;

(3) *Temperature:* Temperature random values must range from approximately 20 °F to approximately 100 °F; and

(4) At the conclusion of the 24-hour period, the following hourly values must meet the criteria in § 3175.141(d) of this subpart:

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(d) *Long-term volume accumulation test.*

(1) Fixed inputs of differential pressure, static pressure, and temperature must be applied to the software version under test to simulate a flow rate greater than 500,000 Mcf/day for a period of at least 7 days.

(2) At the end of the 7-day test period, the accumulated volume must meet the criteria in § 3175.141(d) of this subpart.

§ 3175.144 Flow-computer software test reporting.

(a) The test facility performing the tests must fully document each test required by §§ 3175.141 through 3175.143 of this subpart. The report must indicate the results for each required test and include all data points recorded.

(b) The report must be submitted to the AO. If the PMT determines all testing was completed as required by this section, it will make a recommendation that the BLM post the software version on the BLM's Web site (*www.blm.gov*) as approved software.

§ 3175.150 Immediate assessments.

(a) Certain instances of noncompliance warrant the imposition of immediate assessments upon discovery. Imposition of any of these assessments does not preclude other appropriate enforcement actions.

(b) The BLM will issue the assessments for the violations listed as follows:

VIOLATIONS SUBJECT TO AN IMMEDIATE ASSESSMENT

Violation:	Assessment amount per violation:
1. New FMP orifice plate inspections were not conducted as required by § 3175.80(c) of this subpart	1,000
2. Routine FMP orifice plate inspections were not conducted as required by § 3175.80(d) of this subpart	1,000
3. Visual meter-tube inspections were not conducted as required by § 3175.80(h) of this subpart	1,000
4. Detailed meter-tube inspections were not conducted as required by § 3175.80(i) of this subpart	1.000
5. An initial mechanical recorder verification was not conducted as required by § 3175.92(a) of this subpart	1,000
6. Routine mechanical recorder verifications were not conducted as required by § 3175.92(b) of this subpart	1,000
7. An initial EGM system verification was not conducted as required by § 3175.102(a) of this subpart	1,000
8. Routine EGM system verifications were not conducted as required by § 3175.102(b) of this subpart	1,000
9. Spot samples for low-volume and marginal-volume FMPs were not taken as required by § 3175.115(a) of this subpart	1,000
10. Spot samples for high- and very-high-volume FMPs were not taken as required by § 3175.115(a) and (b) of this subpart	1,000

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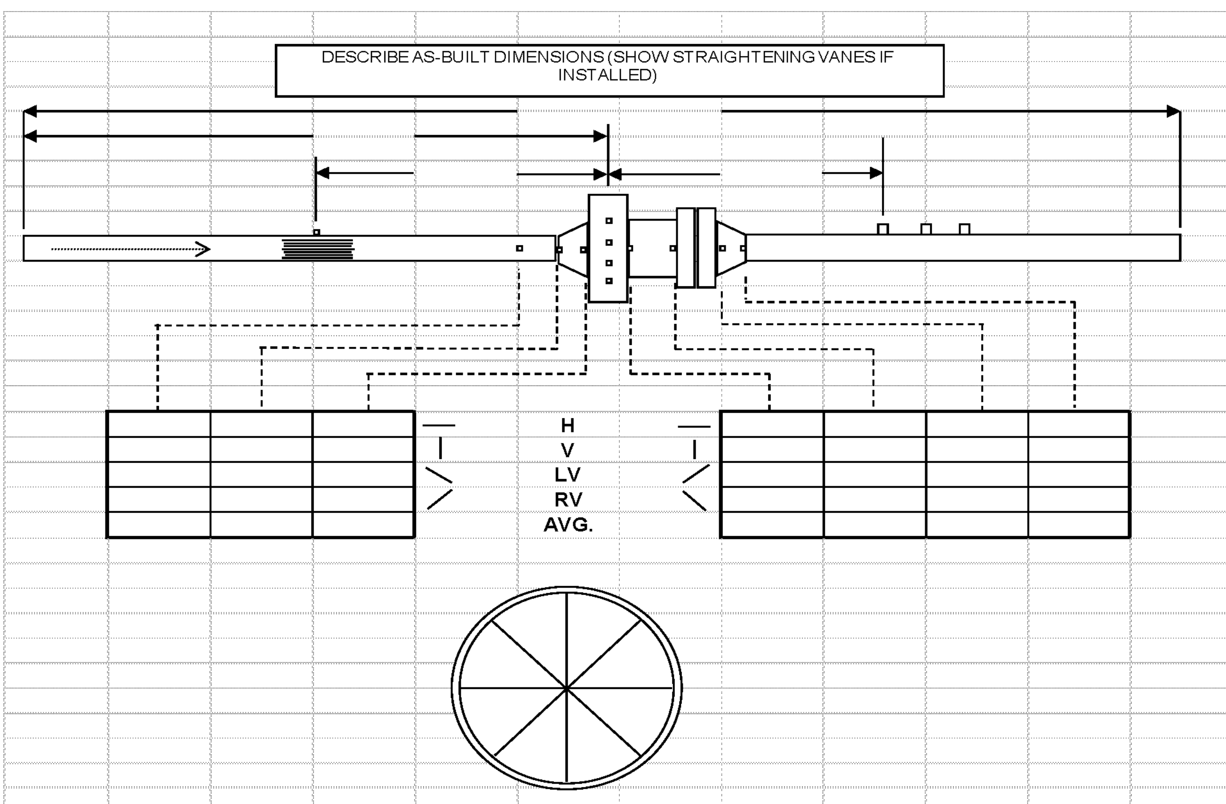
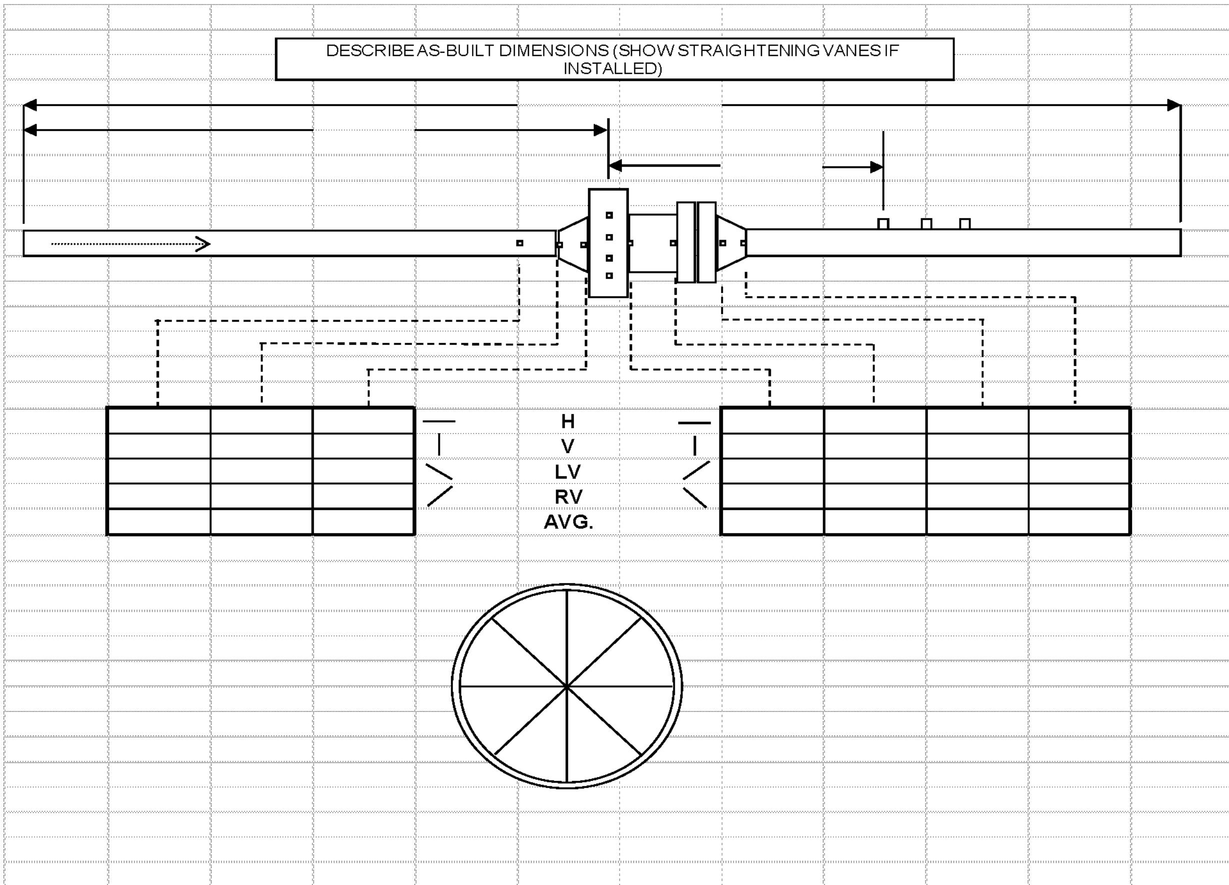
Appendix 1.A– Sample Meter Tube Inspection Form; Simplex Fitting, with Vanes



Appendix 1.B– Sample Meter Tube Inspection Form; Simplex Fitting, no Vanes



Appendix 2 – 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
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

ft msl = feet above mean sea level

Calculated as:

$$P_{atm} = 14.696 \times (1 - 0.00000686E)^{5.25577}$$

where:

P_{atm} is atmospheric pressure, psi
E is meter elevation, feet above mean sea level

From: U.S. Standard Atmosphere, 1976, U.S. Government Printing Office, Washington, D.C., 1976.

Part of the verification process involves venting the pressure device to the atmosphere, recording the reading from the device, and calibrating (adjusting) the reading, if necessary. When a gauge-pressure device is vented to the atmosphere, the reading of the device should be ''zero'' because both sides of the device are sensing atmospheric pressure. The calibrator will calibrate the device to read ''zero'' if necessary. When verifying an absolute pressure device, however, the reading should equal the local atmospheric pressure because one side of the device is sensing atmospheric pressure and the other side of the device is sensing an absolute vacuum. The calibrator will calibrate the device to read local atmospheric pressure if necessary. The most accurate way to determine atmospheric pressure at the time of verification is to measure it with a barometer. Although the use of an atmospheric pressure calculated from elevation results in higher uncertainty, the increased uncertainty is accounted for in the BLM uncertainty calculator.

[FR Doc. 2015–25556 Filed 10–9–15; 8:45 am]

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