Richard Ranger
Senior Policy Advisor
Upstream
1220 L Street, NW
Washington, DC 20005-4070
USA
Telephone 202-682-8057
Fax 202-682-8426
Email rangerr@api.org
www.api.org

June 13, 2017

Mr. Timothy Spisak
Acting Assistant Director
Energy, Minerals, and Realty Management
1849 C Street NW, Room 5625
Washington, D.C. 20240

Re: 43 CFR 3173, 3174, & 3175

Dear Tim:

First of all, on behalf of API and our members, I want to express our thanks and appreciation for the opportunity to meet June 8, 2017 to discuss API's recommendations with respect to the above-referenced rules, which became effective January 17, 2017. We particularly appreciate the participation of so many BLM staff from across the country by teleconference, and hope that their participation was as useful for them as we felt it valuable to us.

API is a national trade association representing over 640 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API member companies are leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

With this letter we provide additional background on the recommendations for revision to the three captioned rules addressing Site Security, Measurement of Oil and Measurement of Gas that we discussed in the June 8 meeting. Also, as we noted at the start of the meeting, in addition to the recommendations for revision that we make in this letter, we reiterate our February 21, 2017 request for postponement to allow consideration of these recommendations for revision, and to ensure that the BLM and regulated community fully understand where and how the regulations apply. We look forward to the BLM's response to that request.

Further, with the recommendations for revision to the rules described in this letter, we also encourage the BLM to follow the PHMSA model and develop a technical advisory group of BLM representatives and industry experts to review proposed revisions to assure the technical feasibility, reasonableness and practicability of each proposal. The simplest and most equitable means of modifying the regulations would be to adopt the American Petroleum Institute (API) and GPA Midstream (GPA) standards in their entirety. The API and GPA standards are based on proven technologies and constitute the consensus of industry's foremost experts in oil and gas measurement as well as the result of input by government agency representatives. The BLM incorporated portions of several API and GPA standards by reference, but overrode many other portions of these industry association guidance documents. If they were adopted in their entirety, the regulations would simply need to specify items such as uncertainty acceptance criteria and verification frequencies.

With this letter, we are also requesting that BLM should consider a minimum threshold of federal ownership before extending the applicability of these replacement rules to all wells within spacing units that include production from federally owned and non-federally owned minerals. For example, in contrast to many states, North Dakota has 95% private land and mineral ownership. Federal minerals are interspersed over 33% of the spacing units, but typically only represent approximately 3% of the ownership. In these instances where the BLM holds a minority ownership in spacing units, State regulations should take precedence. With such a minor federal ownership, the burden to implement BLM regulations is unreasonable. It is proposed that BLM should establish a minimum threshold of 50% federal minerals before extending the Onshore Orders rules to all wells within those spacing units. As discussed in the preceding paragraph, we believe that if the agency and the regulated community move to a greater reliance on voluntary consensus standards, the BLM's concern about the applicability of its rules in cases when BLM holds a smaller interest in a well or lease will be addressed through greater assurance of broad applicability of good practices expressed in the standards.

To return now to our discussion of June 8, as the rules are currently written, there are several changes which would be technically feasible, beneficial, and equitable to all parties. The recommended changes are as follows:

1. § 3170.3 – Definitions and acronyms.

Rule:
Production Measurement Team (PMT) means a panel of members from the BLM (which may include BLM contracted experts) that reviews changes in industry measurement technology, methods, and standards to determine whether regulations should be updated, and provides guidance on measurement technologies and methods not addressed in current regulation. The purpose of the PMT is to act as a central advisory body to ensure that oil and gas produced from Federal and Indian leases is accurately measured and properly reported.

Concern:
This time consuming rule results in the potential for significant delays as the rule is implemented because of the requirement to form a new, nationwide Production Measurement Team to review every existing and new make/model/size of measurement device as well as all electronic flow calculation software. BLM believes it must "approve" every such device and software, regardless of the federal interest, when such measurement is accepted by state agencies, state land interest, all operated/non-operated working interest, and all state/private royalty interest owners. The delay associated with awaiting establishment of the PMT, and the delays that would follow as it conducted its reviews would add significant uncertainty for operators, and likely delay installation of new equipment where doing so might benefit all parties sharing an interest in accurate measurement of lease production. This is a matter of particular concern to operators who are facing the need to develop designs for facilities in the near term for installations that will take place after compliance deadlines in the current rules would take effect without a postponement. We believe the BLM has greatly under estimated the work load for operators and the agency in regard to this aspect of the rule. The filing of new Facility Measurement Points (FMP) will potentially double and perhaps triple the number of gas FMPs. It will likely take years for the BLM to review existing devices/software while operators have no assurance that old or new equipment for which applications are submitted would be approved. The expectation that the BLM will have the technical resources to timely complete this process is questionable with a federal hiring freeze having been ordered earlier this year.

Recommended Change:
Instead of requiring approval of each measurement device installed, BLM should adopt the approach followed by state and private working interest and royalty owners by stating that measurement devices that meet applicable API standards along with flow measurement calculations determined by use of these devices are accepted by BLM. In the course of making this change, BLM could reserve the right to document the uncertainly calculations by means of production audits. All measurement equipment "approvals" should be based on the stated BLM uncertainties of the measurement stations for both liquid and gas. Equipment that meets those uncertainty specifications and that meets the industry standard for the use of that type of device is deemed approved regardless of the brand or model that is used.

2. Tiering Structure; § 3173.12 – Applying for a Facility Measurement Point, § 3174 – Liquid Meter Compliance Obligations

Rule:
The deadlines to apply for an FMP approval and for liquid measurement compliance at existing locations are as follows:
- For a stand-alone lease, unit PA, or CA that produced 10,000 Mcf or more of gas per month or 100 bbl or more of oil per month, by January 17, 2018.
- For a stand-alone lease, unit PA, or CA that produced 1,500 Mcf or more, but less than 10,000 Mcf of gas per month, or 10 bbl or more, but less than 100 bbl of oil per month, by January 17, 2019.
- For a stand-alone lease, unit PA, or CA that produced less than 1,500 Mcf of gas per month or less than 10 bbl of oil per month, January 17, 2020.

Concern:
While 3175 phased the implementation in three evenly spread volume tiers, 3173 and 3174 used monthly numbers for the tiers that are so small (one year is anything over 329 MCFD or 3 BOPD) that nearly every FMP and all liquid measurement compliance would need to be completed in the first year the Rules are in force and effect. The liquid requirement of 100 BOPD is less than one (1) truck haul per day which for shale oil will include almost all leases to comply with the 1st year.

Recommended Change:
We recommend that this section be revised to clarify that the production rates it describes as thresholds refer to gross well production and not to the BLM's net percentage of production. It is also recommended that the tier volumes be adjusted to the following to more evenly phase in the requirement:
- 3173 FMP applications for existing wells/facilities
  - >5,000 MCFD/>500 BOPD – 1 year,
  - 1,000-5,000 MCFD/100-500 BOPD – 2 years,
  - <1,000/<100 BOPD – 3 years.
- 3174 liquid measurement effective dates for existing wells/facilities
  - >500 BOPD – 1 year,
  - 100-500 BOPD – 2 years,
  - < 100 BOPD – 3 years.

3. Cancellation of all Variances, Commingling Agreements, and Off-Site Measurement Agreements

Rule:
As of January 17, 2017 all currently approved variances are no longer valid and all commingling and off-site measurement agreements will be subject to reevaluation and cancelation.

Concern:
Each operator, in good faith, worked with the BLM to achieve variances and agreements which met the requirements at the time of implementation. Cancellation of these variances and agreements has the potential to cost the regulated community a significant amount of capital expenditures to alter operations to meet newly established rules. The increased operational and capital expenses from this rule, and the others listed, have the potential to dramatically impact the economic viability of the affected drilling and production operations, causing them to be shut in earlier than originally planned, reducing the royalties paid to the U.S. Treasury.

Recommended Change:
With the exception of those variances found to have been issued based upon material incorrect information, and so established through adequate documentation, BLM should continue to honor all variances, commingling agreements, and off-site measurement agreements approved prior to the effective dates of the new rules and the new rules should only be applied to applications submitted after the effective date of the new rules.

4. § 3173.11(c)(4) & (c)(6) – Site Facility Diagram

Rule:
(c)(4) If another operator operates a co-located facility, depict the co-located facility(ies) on the diagram or list them as an attachment and identify them by company name, facility name(s), lease, unit PA, or CA number(s), and FMP number(s);
(c)(6) When describing co-located facilities operated by one operator, include a skeleton diagram of the co-located facility(ies), showing equipment only. For storage facilities common to co-located facilities operated by one operator, one diagram is sufficient

Concern:
Operators should not be responsible for submitting any information on other operators' facilities. Each operator is responsible for compliance with the requirements of the Rules and the BLM should not hold one operator responsible for information that is the duty of another operator to provide the agency. At our June 8 meeting we also requested that the BLM provide additional clarity on what the agency will accept in the form of a "skeleton diagram" that does not require detailed information about non-operated facilities.

Recommended change:
Remove the requirement to submit information on non-operated facilities, and/or otherwise clarify that the obligation arising under these subsections of the rules does not require a regulated party to submit information on a facility that it does not operate.

5. § 3173.14(a)(2) – Conditions for Commingling and Allocation (Surface and Downhole)

Rule:
The operator or operators provide a methodology acceptable to BLM for allocation among the properties from which production is to be commingled (including a method for allocating produced water), with a signed agreement if there is more than one operator;

Concern:
The BLM is requiring water volumes in an attempt to account for skim oil. BLM is seeking royalty on skim oil being sold from SWD facilities, even though the operator is not being compensated for any skim oil.

Recommended change:
Clarify that an operator is not required to report minor liquids volumes found in combination with produced water recovered from a well or lease for which the operator receives no compensation. Remove the requirement to allocate produced water and all associated requirements within 3173.

6. § 3173.15(f) & (g) – Applying for a Commingling and Allocation Approval

Rule:
(f) A surface use plan of operations (which may be included in the same Sundry Notice as the request for approval of commingling and allocation) if new surface disturbance is proposed for the FMP and its associated facilities are located on BLM-managed land within the boundaries of the lease, units, and communitized areas from which production would be commingled;
(g) A right-of-way grant application (Standard Form 299), filed under 43 CFR part 2880, if the proposed FMP is on a pipeline, or under 43 CFR part 2800, if the proposed FMP is a meter or storage tank. This requirement applies only when new surface disturbance is proposed for the FMP, and its associated facilities are located on BLM-managed land outside any of the leases, units, or communitized areas whose production would be commingled

Concern:
The Right of Way (ROW) and Surface Use Plan of Operation (SUPO) requirements are outside the scope of surface commingling. The surface commingling application is already extensive and approvals can take six months to two years. Surface disturbance and the mitigation of the effects of surface disturbance are already considered in the approval process for ROW and SUPO, whether for commingling, new well pads, facilities, etc. There is no need to further burden the commingling process with this requirement.

Recommended change:
Remove ROW and SUPO requirement from the rule.

7. § 3173.16(a)(2)(i) & (a)(2)(ii) – Existing Commingling and Allocation Approval

Rule:
The existing CAA is for surface commingling and the average production rate over the previous 12 months for each Federal or Indian lease, unit PA, and CA included in the CAA is:

- (a)(2)(i) Less than 1,000 Mcf per month for gas; or
- (a)(2)(ii) Less than 100 bbl per month for oil.

Concern:
Volumes are too low and therefore most existing commingling permits would no longer be valid. Operators have drilled existing wells under the current rules at a set capital expenditure with a reasonable expectation of profit from both objectives planned for and encountered in one or more given wells. Consistent with prior API-submitted comments to BLM, the practice of commingling offers a suite of benefits. Adding unnecessary operational barriers or costs would result in otherwise recoverable oil and gas reserves being left in the ground, a matter of physical and economic waste for both operators and the federal government as the steward of public lands and collector of royalty and other revenues therefrom on behalf of the nation. In addition, there are considerable environmental benefits with CAAs rather than erecting unnecessary infrastructure, a benefit of that BLM seems to have accorded insufficient weight.

Recommended change:
The BLM should incorporate into the Rule a definition of “economically marginal” that would establish when commingling of production is always allowed from a property meeting that definition. In addition, all existing commingling permits should be honored without further review. If they are not honored, at minimum the volumes should be per day as outlined in the different production tiers as opposed to per month (i.e. Less than 1,000 Mcf per day for gas; or Less than 100 bbl per day for oil).

8. § 3173.21(a)(1) – Combined Production Downhole in Certain Circumstances

Rule:
Combining production from a single well drilled into different hydrocarbon pools or geologic formations (e.g., a directional well) underlying separate adjacent properties (whether Federal, Indian, State, or private), where none of the hydrocarbon pools or geologic formations underlie or are common to more than one of the respective properties, constitutes commingling for purposes of §§ 3173.14 through 3173.20.

Concern:
Production does not occur when a well is drilled. Production begins after completion. Therefore, the rule should state “completed” into different hydrocarbon pools and not “drilled” into different hydrocarbon pools.

Recommended change:
Change the wording within the subpart from “drilled” to “completed”.

9. § 3173.23(e) – Applying for Off-Lease Measurement

Rule:
If any of the proposed off-lease measurement facilities are located on non-federally owned surface, a written concurrence signed by the owner(s) of the surface and the owner(s) of the measurement facilities, including each owner’s name, address, and telephone number, granting the BLM unrestricted access to the off-lease measurement facility and the surface on which it is located, for the purpose of inspecting any production, measurement, water handling, or transportation equipment located on the non-Federal surface up to and including the FMP, and for otherwise verifying production accountability. If the ownership of the non-Federal surface or of the measurement facility changes, the operator must obtain and provide to the AO the written concurrence required under this paragraph from the new owner(s) within 30 days of the change in ownership;

Concern:
This surface ownership information is difficult to obtain when there are multiple owners. To grant BLM unrestricted access to facilities on on-federal surface presents logistical and safety issues and may present concerns to owners of the surface as well. It is ultimately the responsibility of the operator to ensure BLM access to facilities that are located on non-Federal surface lands, and BLM staff should make the request for access to the operator in order that the operator arrange for such access.

Recommended change:
Remove the requirement to provide surface owner information and change to a requirement that operators shall self-certify that BLM has access to facilities, and provide BLM representatives access to such facilities upon request.

10. § 3173.23(f) – Applying for Off-Lease Measurement

Rule:
A right-of-way grant application (Standard Form 299), filed under 43 CFR part 2880, if the proposed off-lease FMP is on a pipeline, or under 43 CFR part 2800, if the proposed off-lease FMP is a meter or storage tank. This requirement applies only when new surface disturbance is proposed for the FMP and its associated facilities are located on BLM-managed land;

Concern:
The off-lease measurement application is already extensive and approvals can take six months to two years. Surface disturbance and the mitigation of the effects of surface disturbance are already considered in the approval process for ROW and SUPO, whether for commingling, new well pads, facilities, etc. The requirement of the new Rule adds unnecessary burden to the off-lease measurement requirements.

Recommended change:
Remove ROW and SUPO requirement from this subpart of the rule.

11. § 3174.11(c)(1) – Meter Proving Requirements

Rule:
Meter proving must be performed under normal operating fluid flow, pressure, temperature, fluid type, and composition. If the operating conditions deviate more than 10% of normal flow rate, 10% of normal absolute operating pressure, 10º F of normal operating temperature, and/or 5º API of the normal operating gravity, a minimum 3 point proving must be performed.

Concern:
Multipoint provings in the field are difficult and impractical. Flow rates and pressures can be altered during provings as long as there is enough fluid available and it does not adversely affect upstream and downstream operations. However, there is no practical way to alter the temperature or the API gravity of the product in order to perform the minimum three point proving.

Recommended Change:
The acceptable deviation parameters for temperature and API gravity should be removed. Routine multipoint provings should not be required. If the resultant values from provings performed over the flow rate and pressure ranges at a given location are linear, and within acceptable deviation criteria, routine provings should only be required to be performed at the current operating conditions.

12. § 3175.80(h)(2) – Flange-Tapped Orifice Plates

Rule:
Basic meter tube inspection must be performed in accordance with the following frequencies:

- Very High Volume – Every Year
- High Volume – Every 2 Years
- Low Volume – Every 5 Years
- Very Low Volume – Not Applicable

Concern:
Meter tube inspections require a significant amount of labor to complete. With the thousands of tubes involved, this has a significant financial impact to the regulated community. It also represents a safety hazard by introducing a potential arc source to a potentially combustible atmosphere. The design of meter tubes can allow for the pooling of hydrocarbon liquids. Purging the tube with inert gases is often not sufficient to bring the atmosphere within the tube below the lower explosive limit (LEL). The hazard and the cost, in many cases, does not add any benefit. In the higher volume tubes, the velocity of the gas has a tendency to keep the tubes clean. There is no benefit to inspecting a meter tube annually when it continues to show no sign of obstructions, pitting, and buildup of foreign substances. Most tubes which will be inspected have been in service for years. If the initial inspection shows no obstructions, pitting, and buildup of foreign substances, the time between inspections should be increased.

The estimated cost to implement that schedule the first year and then maintain it going forward for one E&P company exceeds $1.5 million for annual overhead and operation. Even more of a concern is with an estimated 6085 low volume (5 yr.), 774 high volume (2 yr.), and 29 VH volume (yearly) FMPs, the rule requires the operator to perform 1,633 basic meter tube inspections per year. That company will therefore have to perform 4.4 inspections per day, including weekends and holidays, in order to meet compliance. Most companies will be required to have crews working year-round to satisfy this rule, unless changed. Most of those inspections are performed on "low" volume FMPs. If the BLM were to at minimum remove "low" volume FMP's from the compliance requirements it would significantly reduce the burden on the operators.

Recommended Change:
Initial basic meter tube inspections shall be performed according to the following schedule:

- Very High Volume –Within 2 Year of Effective Date or Installation
- High Volume –Within 3 Years of Effective Date or Installation
- Low Volume – Not Applicable or only at the request of the AO.
- Very Low Volume – Not Applicable

If obstructions, pitting, and buildup of foreign substances are found, perform a detailed meter tube inspection in accordance with 3175.80(h)(6).

Subsequent inspections should be performed according to the following schedule:

- Very High Volume – Every 5 Years
- High Volume – Every 10 Years
- Low Volume – Only at the request of the AO.
- Very Low Volume – Not Applicable

13. § 3175.104(a)(2) – Logs and Records

Rule:
The volume, flow time, and integral value or average extension must be reported to at least 5 decimal places. The average differential pressure, static pressure, and temperature as calculated in § 3175.103(c), must be reported to at least 3 decimal places.

Concern:
Current equipment and reporting software is not capable of reporting to 5 and 3 decimal places, respectively. The proposed rules originally stated 5 significant figures. This was challenged in comments as numbers such as 5,437,260 would need to be reported as 5,437,300. Current reporting programs are incapable of performing the necessary rounding. It was suggested that the number of decimal places be specified. This was answered by simply changing 5 significant figures to 5 decimal places. Once again,

the current equipment used does not report to the required decimal places. If changed to do as such, the values would be meaningless as the equipment is not precise enough for the values to have meaning out to 5 and 3 decimal places, respectively. Statistically speaking, calculated values should not be reported to more significant figures than the root values. This rule will require significant effort and expense for the manufacturers to change software to allow for the required decimal places and for the regulated community to change the software on every possible piece of equipment. It is likely that manufacturers will not develop the software changes for older equipment, forcing complete replacement. The effort and expense will then result in the creation of values which have no significance.

Recommended Change:
The average differential pressure, average static pressure, average temperature, volume, flow time, and integral value or average extension must be reported to the maximum decimal places which the equipment producing the values is capable of measuring.

14. § 3175.112(c)(4) – Sample Probe and Tubing

Rule:
The use of membranes, screens, or filters at any point in the sample probe is prohibited.

Concern:
API MPMS Ch.14.1 and GPA 2166, which set the standards for the collection of natural gas samples, allow for the use of membranes, screens, or filters. This is because liquids, both hydrocarbon and water, do not flow through the gas stream in a homogeneous manner making the collection of a representative sample of the liquid phase virtually impossible. Committees of subject matter experts have many times over the years investigated "wet gas" sampling. However, there is currently no proven technology capable of collecting a representative sample of the liquid phase products within a gas stream. Removing the membrane filters allows liquids to enter the sampling system. In accordance with the standards, samples are heated to at least 30ºF above the hydrocarbon dew point temperature. This is not sufficient to vaporize the collected hydrocarbon liquids. These liquids have the potential to contaminate the sampling system, biasing subsequent samples. This will result in increased uncertainty and variability as well as inaccurate composition and energy values. It also has the potential to damage the instrumentation, resulting in costly repairs.

It is industry practice to measure the composition and energy of the gaseous phase products within the natural gas stream at the royalty measurement point. Liquid phase products are collected and measured downstream. They are then allocated back to each royalty point based on the gaseous composition. This is an equitable and scientifically sound means of ensuring accurate measurement of the gaseous phase products and allocation of the liquid phase products.

Recommended Change:
Gaseous samples should be collected in accordance with API MPMS Ch. 14.1 – "Collecting and Handling of Natural Gas Samples for Custody Transfer" or GPA 2166 – "Obtaining Natural Gas Samples for Analysis by Gas Chromatography".

15. § 3175.113(d)(5) – Spot Sample – General Requirements

Rule:
When taking spot sampling using portable gas chromatographs, at least three replicate samples must be collected and analyzed. For high-volume FMPs, samples must be taken and analyzed until the difference between the maximum heating value and minimum heating value calculated from three consecutive analyses is less than or equal to 16 Btu/ scf. For very-high-volume FMPs, samples must be taken and

analyzed until the difference between the maximum heating value and minimum heating value calculated from three consecutive analyses is less than or equal to 8 Btu/scf. The mean or median heating value and relative density calculated from the three analyses is used for OGOR reporting.

Concern:
Portable gas chromatographs pull live samples from the flowing natural gas stream. Each sample is a unique sample and not a true replicate. It is therefore not appropriate to mandate that the sample stream be steady state as to provide results within given parameters as that is out of the analyst's control. Additionally, in artificial lift applications, the well may not flow long enough to allow for the collection and analysis of three replicates which meet the specified criteria. Restrictions such as these within the rules make the continued use of portable gas chromatographs virtually impossible. It is unclear why a single sample collected into a bottle is sufficient, but a portable gas chromatograph must provide an average of three replicates. If the average value is critical to the accuracy of the results, why would three spot sample bottles not be required from each location? This requirement will create large operational changes for many operators, up to and including the necessity to remove portable gas chromatographs from the field.

When operated properly, portable gas chromatographs allow the analyst to ensure they have collected and analyzed a representative sample while still on-site as opposed to sending a sample off to a laboratory and finding out as much as a month later if the sample was representative.

Recommended Change:
§ 3175.113(d)(5) should be stricken from the rule, removing the requirement for replicate samples when using a portable gas chromatograph.

16. § 3175.115 – Spot Sample - Frequency

Rule:
The BLM may change the required sampling frequency for high-volume and very high volume FMPs if the BLM determines that the sampling required frequency is not sufficient to achieve the heating value uncertainty levels requirements.

Concern:
The proposed rule states that increasing sample frequency will aid in achieving uncertainty requirements. If the same sample collection methods, analytical techniques, and calculation methods are utilized for determination of heating values, the uncertainty will be the same regardless of the variability in the resultant value. Techniques and methodology determine uncertainty, not the resultant values. The variability of the heating value of the gas stream is primarily a function of the ambient, product, and operational conditions, such as ambient temperature and artificial lift.

The study (BLM Gas Variability Study Final Report," May 21, 2010) 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. A BTU swing by itself does not necessarily indicate poor sampling. Furthermore, having a variable gas sampling frequency will cause significant disruptions in organization that already have well established gas sampling frequencies especially by requiring a maximum sampling frequency of once every two weeks.

High heating value samples will vary greatly as atmospheric conditions change. These high heating value samples will be forced into high frequency sampling due to the inherent variability of the product, which is not the same as uncertainty. This will greatly increase the operating expenses of each of these locations with no true decrease in the uncertainty of the analytical results.

Recommended Change:
Section (b) and the associated language in section (d) should be removed from the rule, because the techniques utilized are already stipulated to meet the uncertainty requirements stated in § 3175.30 and the variability of the gas stream has no impact on that uncertainty. Sample frequency should remain as stated in Table 1 of § 3175.110.

17. § 3175.119(b) – Components of Analysis

Rule:
When the concentration of C6+ exceeds 0.5 mole percent, the following gas components must also be analyzed:

- Hexanes; Heptanes; Octanes; and Nonanes +.

Concern:
This rule will require significant changes in operations, replacement of equipment, and increased expense of analysis with no benefit to the heating value calculation. In order to determine if the proposed rule made a significant difference in heating value, and therefore royalty, one company performed a study of 25 field samples. These samples were sent to a third party laboratory for extended analyses to allow for a comparison of the calculated heating value based upon Nonanes Plus analyses and Hexanes Plus analyses. The Hexanes Plus concentrations for the 25 samples were between 0.1860 and 1.1520 Mole%. After removing the samples with Hexanes Plus concentrations less than 0.25 Mole% (the originally proposed threshold), 23 samples remained with Hexanes Plus concentrations between 0.3180 and 1.1520 Mole%. The analyses showed that the maximum heating value loss by analyzing to Hexanes Plus rather than the proposed Nonanes Plus was 4.228 BTU. While that appears to be potentially significant, it is only 0.375% of the heating value of the sample.

The latest model of gas chromatographs provided by one of the industry's leading manufacturers cites a repeatability specification of 0.025% of the heating value. Of the 23 samples evaluated, only one had a percent difference between the calculated heating values which was outside of the repeatability of the instrumentation. All others were well within the specification. The average calculated GC repeatability acceptance criteria for the 23 samples was ±0.280%. However, the average percent difference between the Nonanes Plus heating values and the Hexanes Plus heating values was only 0.112%. The data set clearly shows that the difference between heating values calculated using Nonanes Plus analyses and those calculated using Hexanes Plus analyses is well within the analytical deviation of the instrumentation. Therefore, the rule provides no benefit and should be removed. The complete data is available upon request.

Recommended Change:
The rule should be removed and the compositions should continue to be reported to Hexanes Plus for all samples. The Hexanes Plus fractional percentages (i.e. Hexanes, Heptanes, and Octanes Plus) should be determined through either the use of a 60/30/10 split ratio (60% Hexanes, 30% Heptanes, and 10% Octanes Plus) or characterized by the application of component breakouts determined through annual periodic extended analyses.

Should you have any questions, please contact the undersigned at 202.682.8057, or via e-mail at rangerr@api.org. Thank you for considering the request for postponement and the requests for revision to the rules contained in this letter.

Very truly yours,

Richard Ranger
Senior Policy Advisor
Upstream and Industry Operations
American Petroleum Institute