



Howard J. Feldman

**Director
Regulatory and Scientific Affairs**

1220 L Street, NW
Washington, DC
20005
Telephone: 202-682-8340
Email: feldman@api.org
www.api.org

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Assistant Administrator Regina McCarthy
U.S. Environmental Protection Agency
EPA West (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Attention: Docket ID Number EPA–HQ–OAR–2010–0505

submitted via email to a-and-r-docket@epa.gov

**Ref.: Proposed Rulemaking – Oil and Gas Sector Regulations
Standards of Performance for New Stationary Sources: Oil and Natural Gas
Production and Natural Gas Transmission and Distribution;
National Emission Standards for Hazardous Air Pollutants from Oil and Natural
Gas Production Facilities; and
National Emission Standards for Hazardous Air Pollutants from Natural Gas
Transmission and Storage Facilities
(Docket ID No. EPA-HQ-OAR-2010-0505)**

Assistant Administrator McCarthy:

The American Petroleum Institute (API) is pleased to provide comment on the proposed rulemakings that will modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP) Subparts HH and HHH as a result of EPA's sector-based rulemaking for the oil and natural gas (O&G) industry. API represents more than 480 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports 9.2 million U.S. jobs and 7.7 percent of the U.S. economy, and delivers more than \$86 million a day in revenue to our government. Most of our members will be directly impacted by these proposed regulations.

First, API commends the efforts that your staff has made to learn about the oil and natural gas production industry. With respect to the proposal, we have limited concern with the selected control technologies, which are emission control techniques developed by our industry over many years of operating experience. However, we are concerned about the broad applicability and the one-size-fits-all approach of the proposed rule to regulating an industry that varies greatly in the type, size and complexity of operations.

The following are critical concerns with the proposed rules:

- The proposed rule expands listed categories and applies NSPS to new affected facilities in unique and unprecedented ways that are outside the Agency's authority. There are NSPS sources included in the proposed rule that emit little to no regulated pollutant or are construction-related emissions sources that are temporary (i.e., not routine), neither of which should be included in the rule.
- EPA's schedule will not allow adequate time to review and analyze all stakeholder comments, develop necessary revisions to the rules, and complete internal and interagency reviews. Four months between close of the comment period and promulgation of a final rule is unrealistic and unacceptable for these significant rules impacting an industry as large and vital to the U.S. economy as the oil and gas industry.
- The equipment prescribed to conduct Reduced Emission Completions will simply not be available in time to comply with the current final rule schedule. We believe it will take years to manufacture sufficient specialized equipment and adequately train operators how to safely conduct these operations.
- EPA cost analyses are based on "average model facilities" that do not represent all equipment and compliance costs and, without proper variability analysis to represent the wide variety of operations in the O&G industry, fail to identify when the controls are no longer economic.
- The system of notifications, monitoring, recordkeeping, performance testing and reporting requirements for compliance assurance are overly burdensome for the small and/or temporary affected facilities that EPA is regulating. This is a waste of time and resources for both industry and the EPA.
- EPA has expanded an already conservative risk analysis to include "MACT allowable" emissions and wrongly concluded that additional requirements are needed. The modeling of *actual* emissions under the existing rules indicates that the public is protected with an ample margin of safety.

Therefore, API urges the Agency to:

1. Consult with State air pollution control agency representatives on the expansion of the source category for the new and unique affected facilities as required by CAA §111(f)(3) and re-propose certain new affected source regulations as necessary.
2. Extend the final rule deadline one year to April 5, 2013 to adequately address stakeholder comments.
3. Allow sufficient compliance time (varying from 60 days to at least 2 years) to comply with the equipment specific NSPS requirements following promulgation of the final rule (see technical comments).

4. Revise the economic analyses to include all compliance cost and operational variables. These revised analyses should be used to limit the emission controls applicability to operations where they are economically justifiable.
5. Significantly reduce the compliance assurance complexity and burden by replacing the general provisions notification, recordkeeping and reporting requirements with specific requirements in NSPS, Subpart OOOO. Monitoring and performance testing requirements should be appropriate for small, remote and dispersed sites in the O&G industry.
6. Maintain the existing NESHAP HH and HHH to reflect the low risk posed to the public from these sources.

To facilitate the review of our comments, we have summarized critical issues with the proposed rules in an Executive Summary followed by detailed technical comments. Additionally, we have attached a document with the regulatory language marked up to show how our comments could be accommodated in the regulatory text (Attachment C). Finally, additional attachments are included to document certain points made in our detailed comments.

API remains committed to helping the Agency promulgate a cost effective, clear regulation to reduce the impact of our operations on air quality and look forward to the opportunity to meet and discuss these comments with you and your staff.

We appreciate your consideration of our concerns. If you have any questions, please contact Matt Todd (202-682-8319; todd@api.org) or me.

Sincerely,

/s/

Howard J. Feldman

CC: Bruce Moore, EPA
David Cozzie, EPA
Steve Page, EPA

**API Comments on the Proposed Rulemaking – Oil and Gas
Sector Regulations**

November 30, 2011

**Standards of Performance for New Stationary
Sources: Oil and Natural Gas Production and
Natural Gas Transmission and Distribution;
National Emission Standards for Hazardous Air
Pollutants from Oil and Natural Gas Production
Facilities; and
National Emission Standards for Hazardous Air
Pollutants from Natural Gas Transmission and
Storage Facilities
(Docket ID No. EPA-HQ-OAR-2010-0505)**

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EXECUTIVE SUMMARY

As detailed in our comments, API has numerous concerns with EPA's proposed rulemaking for the Oil and Gas (O&G) sector. However, the control technologies selected in the proposed O&G New Source Performance Standard (NSPS) and revisions to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) O&G regulations are not what cause the concerns. Instead, API's concerns come from the broad applicability of the proposed rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has supported its regulations using economic studies on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The proposed rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, using unsound legal justification and without consulting with the States as required by the CAA. The system of notifications, monitoring, recordkeeping, performance testing and reporting requirements are more burdensome than justified for the small and/or temporarily affected facilities that EPA is regulating. Finally, API is concerned with the pace of this rulemaking. Seven months between the published proposed rule and promulgating the final rule is an unrealistic schedule for issuing a complex rule with the concerns identified that is supposed to cover an industry as large as the O&G production industry. EPA has only four months to review all the submitted comments, analyze them, make appropriate revisions, and complete the necessary internal and interagency reviews.

Listed below in priority order are API's top issues with the proposed O&G rules. API has included a solution to address the issue raised and the rationale behind the solution, with a reference to the detailed comments.

Natural Gas is Not a Surrogate for Volatile Organic Compounds (VOC) and Regulating Low VOC Natural Gas is not Cost Effective and is Equivalent to Regulating Greenhouse Gases (GHG).

Issue – The proposed rule purports to not regulate GHGs, but rather to regulate emissions of natural gas. Many natural gas streams produced today contain little or no VOCs.

Solution – Restrict final rule applicability to streams that have a minimum VOC content to assure that NSPS are cost effective as required by the Clean Air Act.

Rationale – EPA calculated cost effectiveness based on natural gas that is 18% by weight VOC. The cost effectiveness (in dollars per ton of VOC reduced) approaches infinity as VOC content approaches zero. EPA must economically justify its regulations for not just for the average "model" facility, but for reasonably expected variations.

Economic Analysis of Emission Control Strategies Must Be Representative of Industry's Operations.

Issue – The "average model facilities" that EPA has used in the economic analysis do not represent the great variation seen across the U.S.

Solution – The applicability of the proposed regulations must be narrowed to operations in which the proposed emission control practices can be applied in a cost effective manner.

Rationale – Current economic analyses must include the full variety of conditions (i.e., VOC content) in the O&G industry for all of the costs of compliance with the proposed rule. API found

the cost effectiveness for tanks to vary from \$5,271/ton of VOC to \$1,519,667/ton of VOC (Section 16.6.6., Table 3). See Sections 4 & 5.

Expansion of NSPS Source Category is Arbitrary and is Not Allowed Without Consulting with States.

Issue – 42 USC 7411(f) requires consultation with State Governors air pollution control agencies before expanding the listed categories or promulgating new NSPS.

Solution – EPA should conduct the required consultations with the States with significant the oil and gas transportation and distribution sectors and revise the requirements for reduced emission completions requirements, storage vessels, pneumatic controllers, and compressors in NSPS, Subpart OOOO.

Rationale – The uniqueness of the new affected facilities (very small in cost and/or quantity of emissions or the non-routine, temporary construction nature) being justify consultation with states. States will see a massive increase in permitting burden with little to no environmental benefit. See Section 2.

Compliance Assurance Requirements for NSPS Are Overly Burdensome.

Issue – The notifications, monitoring, recordkeeping, testing and reporting requirements for a major source NESHAP regulation are overly burdensome for NSPS Subpart OOOO.

Solution – Specific O&G industry appropriate notification, recordkeeping, reporting, and performance testing sections requirements should be included in Subpart OOOO.

Rationale – The remote, dispersed and unmanned nature of facilities that lack electrical power, make the requirements logistically impractical, technically difficult and uneconomic. The use of NESHAP compliance requirements for storage vessels is confusing and unjustifiably stringent for NSPS. Comment Section 8.

Availability of Equipment and Experienced Operators for Reduced Emission Completions (REC) Requires Delayed Compliance Date.

Issue – The necessary equipment to comply with the REC requirements is currently not available and will require time to manufacture. Also, industry will have a shortage of experienced contractors or staff for safely doing “reduced emissions completions”.

Solution – Due to the limited availability of appropriate and safe equipment and experienced and trained personnel to perform REC's, API requests that compliance with the reduced emissions completions portion of the rule be delayed for 2 years to allow for manufacturing of equipment and training of operators. During the time period from the effective date to two years after the effective date, only the use of completions combustion devices should be required for reducing emissions.

Rationale - The proposed requirement to implement RECs immediately upon the effective date of the final rule does not constitute “the best system for emission reduction.” Comment Section 15.4

Legality of Reduced Emissions Completions Requirements.

Issue – Flowback immediately following hydraulic fracturing stimulation during well completions is not part of the normal operation of a well but is a construction-related activity that must be

accomplished for a well to begin producing and thereafter engage in normal operations. The proposal to regulate construction-related emissions is a significant and substantive departure in the Agency's prior interpretation and implementation of § 111.

Solution – EPA should remove the requirements for reduced emissions completions from the proposed regulation. If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, EPA should repropose the requirements and include sufficient justification for their departure from not regulating construction-related emissions and present the legal basis for regulating non-routine emissions.

Rationale – EPA's failure to explain why the departure from not regulating construction-related emissions is justified and failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C). Comment Section 15.1.

EPA Should Not Prescribe the Equipment Required for Reduced Emissions Completions (REC).

Issue –API is requesting that the rule not require the use of specific equipment. The final rule should allow options to use other emission reduction techniques, not require routing liquids to a storage vessel, and recognize commercial viability.

Solution – API proposes that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods.

Rationale – Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies and section 111(h) allows work practice standards where "it is not feasible to prescribe or enforce a standard of performance." An underlying presumption of section 111 is that a standard of performance should allow the affected facility flexibility to meet a standard, rather than be required to use specific controls. Comment Section 15.2

Applicability for Storage Vessels [NSPS OOOO & NESHAP HH] Must Be Clarified.

Issue – Both NSPS OOOO and NESHAP HH, as proposed, are unnecessarily vague in specifying the storage vessels to which these rules apply.

Solution – Define storage vessels and specify applicability so as to limit applicability to:

- Storage vessels that are located in the oil and natural gas production sector,
- Which are continuously on site for more than 180 days,
- Storing crude oil or condensate,
- With emissions greater than 12 tpy [NSPS OOOO].

Rationale – EPA has a responsibility to clearly specify the sources to which a given rule applies. See Sections 16.1–16.6.

Allow 90 Days to Implement Storage Vessels [NSPS OOOO] Controls at New Production Sites.

Issue – A period of time is necessary to determine whether a new production site will flow at a rate that will trigger the control requirements for storage vessels, and then an additional period of time is necessary to install those controls.

Solution – Specify that applicability shall be determined on the basis of the first 30 days of production and, for sites that trigger controls for storage vessels, compliance shall be achieved within 60 days thereafter.

Rationale – If EPA fails to specify a reasonable compliance period, then storage vessels would potentially need to be equipped with controls at every new production site – just in case the production characteristics might trigger the control requirements. This would clearly result in installing controls at many sites for which controls would eventually be shown to have been neither required nor cost effective. See Section 16.7.

Control Device Requirements for Storage Vessels [NSPS OOOO & NESHAP HH] Must Be Clarified & Reasonable.

Issue – When vapors are required to be routed to a control device, the proposed requirements for the control device are unreasonably complicated and burdensome. For example, there are more than 50 recordkeeping requirements for storage vessels routed to a control device.

Solution – Revise the requirements for control devices for simplification and for suitability to production field operations, including the following:

- Include the “manufacturer certification” option for performance demonstration in NSPS OOOO (confirm the availability of this NESHAP HH option to NSPS OOOO),
- Specify requirements appropriate to an NSPS rule for VOCs in OOOO, rather than invoking the MACT requirements for HAPs from HH,
- Allow electronic ignition for flares, rather than requiring that a pilot flame is present at all times,
- Specify monitoring requirements that are appropriate for remote facilities that may not have an available power source,
- Limit reporting requirements to semi-annual reporting of exceedances, and
- Simplify the recordkeeping requirements.

Rationale – EPA has a responsibility to specify control requirements that are reasonable for the type of facilities found in a given source category. The proposed rule provisions fail to account for the remoteness of production field facilities, the types of technologies that would be most suitable for these facilities, or the volume of unnecessary paperwork that would be required. See Sections 16.10–16.12.

Regulating Small Sources or Construction Activities Using NSPS Is Not Justified by Cost Effectiveness or Legal Precedent.

Issue – EPA has historically regulated emissions during normal operations of a process unit (i.e., a tank, boiler, gas processing plant, etc.). The proposed rule regulate individual components (e.g., a single pneumatic controller) of a process control system and temporary construction emissions (e.g., hydraulic fracturing flowback emissions requiring REC) that have not previously been regulated by NSPS.

Solution – Subpart OOOO regulations for pneumatic controllers, compressors and REC should be revised so the source categories reflect sources that “contribute significantly” to the endangerment of “human health or the environment.”

Rationale – The NSPS general provisions and compliance assurance requirements proposed are not appropriate for the unique emission sources proposed in Subpart OOOO. See Section 2.

Definitions Do Not Represent the Activities of the Oil and Gas Industry.

Issue – The proposed definitions are inconsistent with the way they are used within the O&G industry activities, leading to confusion of which activities are regulated.

Solution – New definitions and revisions for existing definitions have been suggested that accurately describe O&G activities.

Rationale – A common understanding between the agency and regulatory communities of terms is required for a final rule that is clear and enforceable. See Section 6.

Best System of Emission Reduction Must Be Currently Available To Industry.

Issue – EPA has proposed BSER that is not currently available in sufficient quantities for compliance with the proposed rule (especially REC equipment and combustors).

Solution – EPA should phase in the proposed requirements to provide equipment manufacturers and the O&G industry sufficient time to obtain equipment required.

Rationale – Less than 25% of REC equipment needed to comply with the proposal is available. It will take two to seven years to manufacture the equipment. Sufficient combustors that have been tested by the manufacturer to meet the proposed rule requirements are not currently available. Comment Section 7.

Ability to Combust or Vent During Completions Is Needed.

Issue – Paragraphs 60.5375(a)(1) and (2) require “routing recoverable liquids to storage vessels and routing the recovered gas into a gathering line or collection system” and “all salable quality gas must be routed to the gas gathering line as soon as practicable.” API requests more clarity in the rule to address the many operational and safety constraints to routing all salable gas to gathering line

Solution – API proposes that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods.

Rationale – Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies and section 111(h) allows work practice standards where “it is not feasible to prescribe or enforce a standard of performance.” Comment Section 15.3

Relocation of an Existing Compressor Should Not Trigger NSPS Applicability.

Issue – EPA stating that a compressor is considered to have commenced construction on the date the compressor is installed at the facility.

Solution – Remove the last sentence in the applicability sections for centrifugal and reciprocating compressors.

Rationale – The sentence of concern is inconsistent with historical EPA decisions for other NSPS and Applicability Determination Index determinations. Comment Section 18.1.

Pneumatic Controller Affected Facility Should be Redefined as a Process Unit Affected Facility.

Issue – Pneumatic controllers are numerous, small, component level, and inexpensive pieces of equipment for which minor expenditures for routine maintenance, repair, or replacement may trigger

a reconstruction determination setting up the likelihood for unnecessary onerous recordkeeping and tens or hundreds of wasteful and time consuming annual reports per operator.

Solution – Redefine affected facility to “Continuous bleed gas-driven pneumatically controlled process unit” to include all the component parts of a pneumatic control system at a site. Further limiting to “continuous bleed gas-driven” restricts applicable controllers to only those with a weak stream bleed rate of regulated VOC in accordance with the way EPA correctly defines high and low bleed controllers.

Rationale – EPA uses a process unit approach in LDAR to prevent modification and reconstruction triggers for RMRR of fugitive components such as valves. Also, EPA set precedent for this approach in the preamble discussion of the NSPS Subpart YYY proposal [59 FR 46780, 09/15/94]. See Section 17.4.

Revising the MACT Floor Is Not Authorized by the CAA.

Issue – EPA set the MACT floor in the June 17, 1999 rulemaking. The CAA does not give EPA unfettered authority to revise the MACT floor as it desires.

Solution – EPA should not revise the applicability criteria or the control standards for either storage vessels or triethylene glycol dehydrators.

Rationale – CAA 112(d)(2)-(3) allows EPA to set the MACT floor only once. This MACT floor decision was not challenged or overturned by the Court. Revising this MACT floor due to the successful challenge of another category is both inappropriate and unauthorized by the CAA. CAA 112(d)(6) only authorizes the review of improvements in control technology for the revision of the MACT standard. See Comment Section 11.

Removal of 0.9 Mg/yr Benzene Alternative Emission Limitation is Based on Flawed Analysis.

Issue –For subparts HH and HHH, the EPA proposed to remove the 0.9 Mg/yr benzene alternative emission limitation for large dehydrators. In both subparts, there were errors in the analyses. For example, EPA estimated that the cancer MIR based on MACT allowable emissions was 400-in-1 million for subpart HH. Correction of the analysis results in a cancer MIR that is clearly in the range that EPA considers acceptable.

Solution – EPA must correct the errors in the analysis, which will lead to a different conclusion regarding the 0.9 Mg/yr benzene alternative for large dehydrators.

Rationale – Correction of the errors in the analysis result in risk-based outcomes that do not support EPA's proposed decision to eliminate the 0.9 Mg/yr benzene alternative. See Section 20.

Proposed Standards for Small Dehydrators are Unnecessary.

Issue – EPA identified small dehydrators as unregulated emission sources despite the fact that they are effectively subject to standards. In addition, EPA's proposed standards for both subparts HH and HHH are based on faulty MACT floor analyses.

Solution – Eliminate the proposed requirements for small dehydrators. Alternatively, if EPA elects to promulgate standards for small dehydrators, it must establish subcategories that appropriately account for fundamental differences among small dehydrators in determining the "classes, types, and sizes" of sources to be regulated and determine MACT floors for the subcategories.

Rationale – The dual use of 0.9 Mg/yr benzene as criteria for separating small and large dehydrators and as an emission limitation for large dehydrators effectively creates a situation where all dehydrators are subject to standards. This is consistent with the original MACT floor determination for dehydrators, which did not distinguish between dehydrator subcategories. Therefore, EPA should not promulgate any standards for small dehydrators.

If EPA does elect to move forward with promulgating standards for small dehydrators, EPA must take into account fundamental differences in dehydrators, most importantly the naturally occurring concentration of HAP in the gas stream, create appropriate subcategories, and determine MACT floors for each subcategory. See Section 20.

Equipment Leaks – Lowering the Leak Definition from 10,000 ppm to 500 ppm.

Issue – EPA proposes to lower the leak definition for valves at natural gas processing plants from 10,000 ppm to 500 ppm, which would not lead to any substantial VOC emissions reductions.

Solution – The leak definition for valves at gas plants should remain at 10,000 ppm. In lieu of imposition of 500 ppm leak definition, API recommends the valve LDAR program at gas plants includes the following two elements: 1) once meeting the requirement of no leak detected during monthly monitoring initially, all valves are, and continue to be, monitored on a quarterly basis with no skip periods ; and 2) the owner or operator would identify "chronic leaks" (i.e., valves that leak above 10,000 ppm in three of any consecutive four quarters), and designate these valves for refurbishing or replacement during the next process unit shutdown.

Rationale – EPA overestimated valve control-effectiveness, which is confirmed by the data provided by API member companies. The proposed leak definition for valves would be burdensome without achieving the VOC reduction as claimed by EPA. See Sections 19.1.1 and 19.1.6.

Equipment Leaks – Imposition of a Connector Program.

Issue – EPA proposes to require a leak detection and repair (LDAR) program for connectors at natural gas processing plants, with a leak definition of 500 ppm, while the existing rule only requires auditory, visual and olfactory (AVO) inspections.

Solution – API recommends that no new LDAR program for connectors be imposed at natural gas processing plants, and that connectors continue to be subject to the AVO requirements.

Rationale – EPA overestimated the emissions reduction and underestimated the cost of the proposed connector LDAR program, resulting in an overly inflated cost-effectiveness estimation. See Sections 19.1.2 and 19.1.6.

INTRODUCTION

On August 23, 2011, the US EPA proposed to modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP) Subparts HH and HHH. API has prepared the following detailed comments in response to this proposed sector-based rulemaking for the oil and natural gas (O&G) industry.

API appreciates the efforts that EPA has made to learn about the oil and natural gas production industry (O&G industry) and taking the time to tour production fields and request information on the industry. API was pleased to be able to offer presentations and white papers on various aspects of the O&G industry. Copies of these presentations and white papers have been included in Attachment A for your convenience.

EPA has requested comments on a wide variety of issues. API has tried to supply information on these requests throughout the document. Attachment B is provided to cross reference these request with sections where this information is located. API regrets that time during the comment period was insufficient to gather the type or quantity of information needed to properly answer EPA's questions. However, much of the information is simply not available. Surveys, studies and research would have to be commissioned to provide the information requested. EPA should have commissioned these events during the pre-proposal stage of the rulemaking. EPA simply did not invest the time and resources for a rulemaking of this magnitude.

Finally, EPA has requested during meetings that solutions be provided for the concerns being raised in these comments and that revised regulatory text be suggested to implement these solutions. Attachment C provides revised regulatory text in redline/strikeout format for this purpose with reference to the sections that discuss these revisions. While Attachment C has been prepared as a summary of API's suggested edits to the rule language, the markups shown in these comments should be taken as our preferred position in the event of any differences between these comments and Attachment C.

API remains committed to helping the agency promulgate a cost effective, clear regulation to reduce the impact of our operations on air quality and look forward to the opportunity to meet and discuss these comments soon.

GENERAL COMMENTS

1. EXTENSION OF COMMENT PERIOD AND FINAL RULE DEADLINE

1.1. Extension of Comment Period to 90 Days Remains Insufficient for Adequate Comments

API continues to believe that industry needed a full 120 days to provide an adequate set of comments to a rulemaking as broad, high impact, precedent setting, and complex as these proposed rules. However, API appreciates the additional 30 day extension that EPA provided. API has developed as complete a set of comments as time allowed. Much of the information EPA requested, as well as additional information API wanted to provide, is not included because of time limitations.

1.2. Insufficient Time for Agency to Review Comments and Revise and Finalize Rule

API also continues to believe that the revised final rule deadline of April 3, 2012 needs to be delayed a full year to allow EPA sufficient time to fully review and give reasoned responses to the comments as required by the Administrative Procedures Act (APA). Given the complexity of the issues, the many competing demands on Agency resources, and the time that will be needed to complete interagency review of the draft final rules, the agency is fully justified in extending the final rule promulgation date to February 28, 2013.

1.3. Consent Decree Does Not Require Promulgation of Rules for New Affected Facilities

It is worth noting in this regard that the settlement agreement itself does not dictate that EPA issue a final rule that is commensurate with the scope of the proposed rule. Indeed, EPA's proposal goes well beyond the scope even contemplated by the settlement agreement. With respect to Section 112, the settlement agreement provides that EPA was to propose and shall take final action under Sections 112(d)(6) and 112(f)(2). With respect to Section 111, the settlement agreement provides that EPA shall sign one or a combination of the following for the NSPS Subparts KKK and LLL:

- (a) a proposed rule containing revisions to the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (b) a proposed determination not to revise the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (c) a proposed or final determination not to review the NSPS (in whole or in part) under CAA section 111(b)(1)(B).

For final action, it commits EPA to "sign one or a combination of the following for NSPS Subparts KKK and LLL:

- (a) a final rule containing revisions to the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or

- (b) a final determination not to revise the NSPS (in whole or in part) under CAA section 111(b)(1)(B); and/or
- (c) a final determination not to review the NSPS (in whole or in part) under CAA section 111(b)(1)(B).”

API believes that many of the proposed rule requirements have been inadequately proposed (especially the expansion of the Oil and Natural Gas Sector and addition of affected facilities) and a supplemental proposal is needed. If EPA cannot extend the comment period and final rule deadline as discussed above, then API recommends that EPA separate the portions of the rule required by the consent decree from the voluntary additions to the rulemaking, so appropriate consideration can be given to these unique provisions.

2. EXPANSION OF NSPS SOURCE CATEGORY

To date, EPA has established only two NSPS for the oil and gas production sector – Subpart KKK, applicable to VOC equipment leaks at gas processing plants, and Subpart LLL, applicable to sulfur dioxide emissions from gas processing plants. In the proposal, EPA would expand its NSPS regulations for the oil and gas production sector to include requirements for numerous additional source types; including completions of hydraulically fractured gas wells, VOC standards for gas-driven pneumatic devices, standards for centrifugal and reciprocating compressors, and tank standards. 76 Fed. Reg. at 52745-52746. These standards would apply throughout the sector, from production wells, to gas processing, to transmission to local distribution systems.

EPA asserts that it is authorized to expand the scope of the current rules because it “believe[s] that the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.*, production, processing, transmission, storage and distribution).” *Id.* at 52745. Alternatively, EPA declares, “To the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b), we hereby modify the category list to include all operations in the oil and natural gas sector.” *Id.* As justification for such a modification, EPA explains only that “Section 111(b) of the CAA gives the EPA broad authority and discretion to list and establish NSPS for a category that, in the Administrator’s judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare” and, pursuant to this authority, “we are modifying the source category list to include any oil and gas operation not covered by the current listing and evaluating emissions from all oil and gas operation at the same time.” *Id.*

EPA is wrong on both counts.

2.1. Current source category does not cover all operations in this industry

As to the scope of the original listing of the “crude oil and natural gas production” source category, EPA made it clear that the category was listed to satisfy CAA § 111(f). 44 Fed. Reg. 49222 (Aug. 21, 1979). Section 111(f) required EPA to create a list of “categories of major stationary sources” that had not been listed as of August 7, 1977 under § 111(b)(1)(A) and to promulgate NSPSs for the listed categories according to a set schedule. EPA explained in the listing rule that its list included “major source categories,” which EPA defined to include “those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant.” *Id.*

While EPA provided no further explanation in its original listing decision as to what facilities it intended to regulate under the “crude oil and natural gas production” source category, there can be no doubt that the category originally included “stationary sources” (*i.e.*, “plants”) that typically have a potential to emit at least 100 tons per year of a regulated pollutant. This communicates two important limitations on the original listing decision. First, EPA was focused on discrete “plants” or “stationary sources.” Second, EPA was focused on large emitting plants or stationary sources.

As a result, the original listing decision cannot reasonably be interpreted to extend to the types of sources EPA seeks to regulate in the proposal. For example, typical production wells do not have the potential to emit major amounts of any regulated pollutant. Thus, they could not reasonably have been considered major-emitting plants at the time of the original listing decision. The same is true for compressors, tanks, and pneumatic devices scattered along gathering and transmission lines. EPA could not plausibly have considered such transportation and distribution sources to be major emitting plants.

Nevertheless, EPA claims that the source category should be construed broadly because, “In the [1979] notice that listed source categories (including Oil and Natural Gas) for promulgation of NSPS, we noted that there were discrepancies between the source category names on the list and those in the background document, and we clarified our intent to address all sources under an industry heading at the same time.” 76 Fed. Reg. at 52745. But, that is not what the Agency said in 1979. Rather, EPA explained in 1979 that the discrepancies were “a result of aggregation of sources which had been subcategorized for size classification and priority ranking analysis in the background document” and that “all source categories under a generic industry heading, such as non-metallic mineral processing, will be evaluated at the same time, although this does not necessarily imply that a single standard would apply to all sources within the listed category.” 44 Fed. Reg. at 49225. Nothing in this explanation suggests that EPA intended to regulate non-major sources under § 111 by “aggregating” them with major sources. In context, EPA was simply saying that categories or subcategories of stationary sources that otherwise met the listing criteria (*i.e.*, plants that typically are major emitting) were sometimes lumped together into a single category for listing purposes. Thus, EPA’s “aggregation” decisions do not lend support to an expansive interpretation of the “crude oil and natural gas production” source category.

It is telling that, when the Agency eventually established NSPS for this source category, it decided to only regulate natural gas processing plants – the closest thing to a major-emitting plant that can be found in this sector. Thus, EPA’s prior actions speak louder than its words in the current proposal.

2.2. EPA is not Authorized to Arbitrarily Expand a Source Category

EPA’s claim that it is authorized to expand the scope of the original source category “to include any oil and gas operation not covered by the current listing and evaluat[e] emissions from all oil and gas operation at the same time” is equally unavailing. EPA is authorized to regulate “a category” of stationary sources under § 111 only if, in the judgment of the Administrator, the category “causes, or significantly contributes to, air pollution which may reasonably be anticipated to endanger public health or welfare.” CAA § 111(b)(1)(A). For now, the “category” of stationary sources that EPA regulates in the oil and gas sector consists of natural gas processing plants. The additional types of

sources that EPA seeks to regulate in the proposal are distinctly different types of stationary sources than gas processing plants. For example, an oil or gas production well is a stationary source, but it clearly is not a processing plant. Similarly, compressors, tanks, and pneumatic devices are stationary sources, but they also are plainly not processing plants. Such sources might be *part* of a gas processing plant (and, therefore, possibly susceptible to regulation as part of a gas processing plant), but if they are not part of a gas processing plant, they constitute a different kind of stationary source.

Thus, EPA is authorized to regulate these additional source types if and only if it: (1) defines a discrete “category” of stationary sources; and (2) determines that emissions from the source category cause or significantly contribute to endangerment to health or the environment. Since EPA has not defined such additional source categories or made such endangerment/contribution findings, EPA is not authorized to “expand” the scope of the “crude oil and natural gas production” source category.

Even if EPA had such authority, it would be arbitrary and unreasonable to expand the source category as proposed. To begin, EPA makes no effort whatsoever to demonstrate that emissions from the additionally-regulated sources cause or contribute to endangerment to health or the environment. Instead, the Agency simply asserts that it may evaluate “emissions from all oil and gas operations at the same time.” 76 Fed. Reg. at 52745. This failure to investigate the key statutory listing criteria is patently arbitrary and plainly violates the § 307(d)(3) requirement to clearly set forth the basis and purpose of the proposal.

In essence, EPA appears to be arguing that, since it determined that certain types of stationary sources within an industry sector cause or significantly contribute to endangerment to health or the environment, it is free thereafter to amend the source category to include all manner of ancillary equipment and operations (regardless of the quantity of emissions) because a teaspoonful of additional emissions contributes to the previously-identified endangerment. This is not a reasonable interpretation of § 111(b)(1)(A) because such an interpretation would bestow virtually unlimited regulatory authority upon EPA – allowing EPA to evade the express listing criteria by creating loose associations of nominally related source types.

The proposal is a case in point. Oil and gas production wells are fundamentally different stationary sources than gas processing plants. Yet, EPA asserts that its long-ago decision to regulate gas processing plants under § 111 somehow enables the Agency to now regulate production wells because the wells are associated with gas processing plants by virtue of being in the same industry sector. Even worse, EPA employs the same rationale to claim authority to regulate pneumatic devices in the sector – including single devices located anywhere on a pipeline and not necessarily associated with a “plant” or “stationary source.” Guilt by association is not a reasonable interpretation of the Act and does not satisfy EPA’s threshold obligation to clearly define a category of stationary source and show that emissions from that category of sources causes or significantly contributes to endangerment to health or the environment.

Lastly, CAA § 111(f)(3) requires EPA to “consult with appropriate representatives of the Governors” prior to “promulgating any regulations under this subsection.” As explained above, EPA originally listed the “crude oil and natural gas production” source category pursuant to § 111(f)(3). Thus, EPA has a clear obligation to consult with the Governors and should do so prior to proposing the rule so that the public has an opportunity to know the views of the Governors and submit comments on the

record. EPA's failure to consult with the Governors prior to proposal is a fundamental procedural error.

2.3. Extremely Small Affected Facilities

EPA makes similar errors in asserting that single individual components (such as pneumatic devices, compressors, and tanks) and single activities (such as each well completion) constitute separate "affected facilities" under the rule. *See, e.g.*, 76 Fed. Reg. at 52746 ("We are proposing that each pneumatic device is an affected facility."). The clear purpose of this approach is to expand the universe of "new sources" that will become subject to the final rules. *See, e.g., id.* ("Accordingly, the proposed standards would apply to each newly installed pneumatic device (including replacement of an existing device)."). This proposal to finely parse the definition of affected facility in order to expand applicability of the rules is fundamentally flawed for three distinct reasons.

2.3.1. EPA Has Failed to Explain Legal Authority

First, EPA has completely failed to explain where it finds legal authority for such an approach. The closest that EPA comes is to state that individual pieces of equipment constitute an "apparatus" and to vaguely refer to "the definitions of "affected facility" and "construction" at 40 CFR 60.2." *See, e.g., id.* at 52761. This explanation is indecipherable and, thus, falls far short of EPA's obligation to include in the proposed rule "the major legal interpretations ... underlying the proposed rule." CAA § 307(d)(3)(C).

2.3.2. Affected Facility Must Match the Source Category

More importantly, the proposal is flawed because the statute simply does not confer authority on EPA to define a source category and then define a different "affected facility" for purposes of determining what constitutes a new source. As explained above, the statute unambiguously requires EPA to identify and regulate "categories of stationary sources." CAA § 111(b)(1)(A). Similarly, the statute defines the term "new source" to mean "any stationary source" that is constructed or modified after proposal of an applicable standard. *Id.* at § 111(a)(2). There can be no doubt that the "stationary source(s)" that is identified for listing purposes must be the same "stationary source" used to define what constitutes a new source. In other words, by defining a category of "stationary sources" to be regulated under § 111, EPA unavoidably identifies the "stationary source" that must be used in applying the definition of "new source."

To be sure, § 111 provides EPA with regulatory flexibility – the Agency clearly "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." *Id.* at § 111(b)(2). However, the authority to parse a given category of stationary sources for purposes of standard setting is distinctly different from the asserted authority to redefine what constitutes a "new source" within the given source category. *Asarco Inc. v. EPA*, 578 F.2d 319, 327 n. 24 (D.C. Cir. 1978) ("This language on its face merely allows the Administrator to set different standards for different classes, types, and sizes of sources. It does not give the Administrator authority to rewrite the definition of a stationary source ..."). EPA has flexibility in defining in the first instance the stationary

sources to be regulated, but the act of defining the “stationary sources” fixes the “affected facility” for purposes of determining what constitutes a new source.

2.3.3. EPA Has Failed to Follow Established Criteria

Third, even assuming (for the sake of argument) that EPA has authority to designate portions of stationary sources as “affected facilities” for purposes of determining what constitutes a “new source,” EPA has failed to follow the analytical framework established in prior rules for making such designations. For example, in establishing the NSPS for VOC emissions from synthetic organic chemical manufacturing wastewater, EPA explained that a balancing must be done. A “narrower” definition of affected facility can be favorable because “a broader definition means that replacement equipment is less likely to be regulated under the NSPS.” 59 Fed. Reg. 46780, 46789 (Sept. 12, 1994). On the other hand, a “broader” definition may be appropriate upon consideration of “the relevant statutory factors (technical feasibility, cost, energy, and other environmental factors).” *Id.* In the case of this SOCM rule, EPA selected the process unit as the appropriate affected facility because it “allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards.” *Id.* at 46790. The failure to engage in reasoned assessment according to these established criteria renders the proposed rule arbitrary and capricious and not in accord with the law.

2.4. Temporary Emission Sources (Completions)

Emissions from well completions are fundamentally different than emissions regulated under any existing NSPS. It goes without saying that the purpose of gas wells is to produce natural gas. A well completion is not part of the normal operation of a well, in that completion activities do not continuously occur as a well is producing or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be “recompleted,” this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

To date, EPA has not sought to impose § 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA has actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until “within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.” 40 C.F.R. §60.8(a). Similarly, performance test must be conducted under conditions reflecting “representative performance of the affected facility.” *Id.* at §60.8(c). Periods of source construction and maintenance have never been determined to be “representative” of normal source operation under the NSPS program.

With this as a backdrop, EPA's proposal to set standards for well completions and recompletions is unfounded. To begin, as discussed more fully in Section 15.1 of these comments, production wells

are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and gas production industry (such as natural gas processing plants) that EPA seeks to regulate in the proposed rule. EPA has not previously found and has not proposed to find that emissions from production wells cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate oil and gas production wells under § 111.

In addition, EPA has not explained why it has reversed a decades-long practice under § 111 of regulating only emissions from normal operation of affected facilities and expressly excluding construction-related emissions from regulation. The proposal to regulate construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of § 111. The failure to explain why this departure is justified and the failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C).

3. BOUNDARIES FOR THE OIL AND NATURAL GAS PRODUCTION SECTOR

3.1. Boundary Between the Production and Transportation Sectors

EPA, in the preamble to the proposed rules, presents a description of the oil and natural gas sector that would clearly expand the boundaries of the oil and natural gas production source category from that listed in 1979. The preamble states, "We consider the oil refinery sector separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector" (76 FR 52744, bottom of middle column). This statement would expand the oil and natural gas sector to include all pipeline facilities all the way to the refinery fence, which is almost surely not the intent. Such an expansion of the oil and natural gas sector would overlap with the oil and natural gas pipeline transportation sector, which is already regulated by NESHAP Subparts HHH and EEEE (OLD MACT) and NSPS Subpart Kb.

Having Subpart HH coverage overlap Subparts HHH and EEEE is unreasonable and unlawful because sources are included in two source categories and regulated under two standards. Under the proposal, it would seem some sources currently regulated under subparts HHH and EEEE might no longer be subject to those rules and instead would be subject to subpart HH on the basis that only one NESHAP applies to any individual source. At a minimum, there would be significant confusion and compliance liability over which rules apply to such sources, whether rule applicability has been correctly assigned in the past and whether the MACT floor analyses for Subparts HHH and EEEE inappropriately included sources from the oil and natural gas production source category. At minimum, any change in Subpart HH applicability must be clearly identified in rule language as applying only from the date of proposal, rather than retroactively, and overlaps with Subparts HHH and EEEE must be specifically addressed.

The point of custody transfer where the hydrocarbon liquids enter the transportation industry has always been the demarcation of the end of the production sector and the beginning of the transportation sector. The current definition of custody transfer in Part 63 Subpart HH (below) is typical of the definitions in NSPS Subpart Kb and NESHAP Subparts HHH and EEEE, each of

which describe this point as being where oil or natural gas is transferred from production or producing operations to “pipelines or any other forms of transportation.”

§63.761

Custody transfer means the transfer of hydrocarbon liquids or natural gas: after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Although oil and natural gas are measured at and pass several “accounting transfers” (such as lease accounting for royalty purposes, and gathering and gas plant balance for product loss and shrinkage purposes), products often are not transferred from the production operator until the product is loaded onto trucks or into a pipeline to leave the field. Additionally, using the last point before the oil or natural gas leaves the production field allows the NSPS and NESHAP regulations to use the same regulatory demarcation between the production and transportation sectors, as specified in CAA section 112(c).

As EPA accurately points out, “hydrocarbon liquids can pass through several custody transfer points between the well and the final destination”. However, this is not a good reason to abandon the best point of physical demarcation between production and transportation sectors that the agencies and industry has found. This rulemaking should clearly define which point of custody transfer is intended for this dividing point. API recommends that this dividing point be the last point of custody transfer before the crude oil or condensate leaves the production field and enters the transportation industry. This would most closely match the original intent of the custody transfer definition in the final NSPS Subpart K of March 8, 1974 and the common practice of the oil and natural gas industry.

Furthermore, API feels it is inappropriate to include the natural gas transportation (transmission) sector in NSPS Subpart OOOO for the reasons discussed in Section 5.1 on the low VOC natural gas streams. EPA states that the purpose of this NSPS is to control emissions of VOC and SO₂. However, there is no SO₂ and very little VOC to control in the natural gas stream after the gas processing plant. EPA recognized this when they exempted residue gas (gas after the extraction of NGLs) from the provisions of NSPS Subpart KKK. In addition to inappropriately expanding the source category, including the natural gas transportation sector in NSPS Subpart OOOO ignores this fact and amounts to the “backdoor” regulation of greenhouse gases (GHGs) because methane is the only substance effectively regulated for low VOC natural gas streams.

If EPA feels there is a need to add new requirements for the transportation and distribution sectors, it should revise existing subparts that already apply to them (i.e., NSPS Subpart Kb for tanks) or create a new subpart if necessary. Adding these sectors as part of a review for the production sector inappropriately reduces the opportunity of the transportation and distribution sectors from commenting on the proposed rules.

API requests that EPA define the boundary of the Oil and Natural Gas Production sector as the last point of custody transfer before leaving the production field, as suggested below, and that the title of NSPS Subpart OOOO be edited to delete the reference to the transmission and distribution sectors.

Suggested Rule Text:**Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution****§60.5365**

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service or in wet gas service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5430

[Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.](#)

These changes would render NSPS OOOO consistent with NESHAP HH and HHH, as those rule were originally promulgated. The rule text adjustments below are necessary to return the proposal language to the original intent.

NESHAP HH

Return to the original language qualifying the affected facility.

§63.760(a)(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point [of custody transfer](#) ~~where hydrocarbon liquids enter either the Organic Liquids Distribution (Non-gasoline) or Petroleum Refineries source categories.~~

NESHAP HHH

No changes are required to NESHAP HHH, in that the proposed revisions leave the “point of custody transfer” qualifier in place.

3.2. Boundary Between the Transportation and Distribution Sectors

API supports the comments of the American Gas Association (AGA) regarding the boundaries for the natural gas distribution sector under Subpart OOOO. As in the case of the production sector, the boundaries of other sectors in our industry are also defined by the point where the hydrocarbons leave one sector and enter another. Natural gas local distribution utilities usually obtain their supply of natural gas from upstream interstate transmission pipelines. Some gas utilities also obtain pipeline

quality dry natural gas directly from local production or from another adjacent gas utility, without an intervening interstate pipeline. The boundary for the distribution sector occurs at the point where custody of the natural gas is transferred from an upstream interstate transmission pipeline or from local production to a local natural gas distribution utility company. Subsequent transfers of custody from one distribution utility to another would mark the boundary between the two utilities, but would occur within the distribution sector.

EPA uses the term "city gate" loosely in Subpart OOOO to indicate the boundary between distribution and upstream sectors, but the agency has not defined the term or proposed a clear definition of the boundary between the natural gas distribution sector and other sectors of the industry. Although EPA added distribution to the *description of the source category* for Subpart OOOO, we understand that EPA did not intend to apply any of the proposed *standards* on the low VOC natural gas streams in natural gas distribution. This makes it essential to define the boundary of natural gas distribution clearly. Using the term "city gate" will not serve this purpose. AGA notes in its comments that the term "city gate" does not have a consistent meaning within the distribution sector. It is used by different gas utilities in different ways to refer to a wide variety of different types of facilities.^A

Suggested Rule Text:

Accordingly, to avoid confusion, we agree with AGA that EPA should replace the term "city gate" with the term "custody transfer station" and should add the following definition to §60.5430:

§60.5430

Custody transfer station means a facility where custody of natural gas is transferred from an interstate transmission pipeline or local producer to a natural gas local distribution utility.

If this change is made, then the term city gate should be replaced wherever it appears in Part 60, Subpart OOOO with the term "custody transfer station." This would avoid confusion that would otherwise arise from using the term "city gate."

As noted in section 3.1 above, §60.5365 should be qualified to pertain to "a site prior to the point of custody transfer at which is located." The definition of custody transfer suggested in section 3.1, would mark the division between production and "pipelines *or any other forms of transportation.*" This is intended to encompass transportation in distribution systems. In combination with the above revision to §60.5365, this would clearly exclude the natural gas distribution sector from the application of Subpart OOOO, which we understand is consistent with EPA's intent.

4. ECONOMIC ANALYSIS FOR DETERMINING BEST SYSTEM OF EMISSION REDUCTION (BSER)

^A AGA had a similar concern with the Mandatory Greenhouse Gas Reporting Rule for Natural Gas Systems, 75 Fed. Reg. 74,458. In that rulemaking, EPA responded to AGA's comment on the term "city gate" used in the GHG reporting rule by proposing to delete the term "city gate" and replacing it with a different defined term in its recently proposed technical revisions to 40 C.F.R. Part 98, Subpart W. See 76 Fed. Reg. 56,010, 56,028 (Sept. 9, 2011). See also AGA's comments on the Subpart W Technical Revisions, filed Oct. 24, 2011 in Docket EPA-OAR-2011-0512.

The Clean Air Act (CAA) requires EPA to set NSPS at the BSER, considering economics, which have been adequately demonstrated. In performing the economic analysis, EPA created a model for each "affected facility" that was used to perform the required economic analysis. These models contain assumptions for a "typical" affected facility within the industry. One of API's primary concerns with the proposed rule centers around the lack of sufficient sensitivity analysis for these model affected facilities with the economic justification for each control strategy that was determined to be BSER.

4.1. Unique Conditions of the Oil and Gas Industry

The O&G industry differs from most other industrial sectors in that the naturally-occurring dynamic reservoir properties control how we produce and manage the oil and natural gas from the reservoir. Most industries purchase their feedstocks to a set specification and have significant control over each step of the process. When the O&G industry finds a petroleum reservoir, the composition of the petroleum, the temperatures, and pressures of the fluids are dictated by the reservoir. These properties start to slowly change as soon as oil and gas begin being withdrawn from the reservoir. The volume of petroleum withdrawn from the well decreases every year (referred to as depletion) as does the pressure it is produced at. The composition of the petroleum changes (e.g. the gas to oil ratio [GOR], the amount of propane, butane, etc. in the gas, the characteristics of the crude oil, etc.) as does the volume and quality of produced water that comes with it. The O&G industry is constantly required to adapt to these changes. New wells must be drilled to replace the loss of production volume as the well depletes. Compressors must be added to compensate for the loss of well pressure, etc.

Additionally, each reservoir has a completely separate set of properties. For example, "conventional wells" of the past might flow oil and/or gas as soon as the well is drilled. Some of these conventional wells produce a very heavy, thick crude oil (a.k.a. black oil or dead oil) that has no associated natural gas at all. Other conventional wells may produce very light hydrocarbon liquids (a.k.a. condensate) along with high amounts of natural gas. While conventional O&G reservoirs are still producing today, the majority of new reservoirs are typically referred to as "non-conventional" since the reservoir characteristics and storage mechanism can be very different from those of conventional reservoirs. Non-conventional wells include formations such as coal bed methane (CBM), tight sands, and shale. Each type of formation may have some similarities, but still can have wide variation. CBM typically are produced at low pressures and contains very high percentage of methane (often as high as 97% by volume) and almost no hydrocarbons heavier than ethane. However some geographic areas of CBM can produce some liquid hydrocarbons. Some tight sands behave like sand stone and can produce significant amounts of heavier hydrocarbons. Shale fields run the gamut from wells that produce nearly 100% methane to wells that produce significant quantities of hydrocarbons that are liquid at stock tank conditions. The definitions of the various types of reservoirs are very broad and the defining characteristics have little to do with the reservoir's potential to emit VOC or HAP.

4.2. Economic Models and Variability

From the conversation above, it is clear that there is no one-size-fits all model to describe the O&G industry. For example, EPA looked at natural gas compositions that had no VOC content at all up to 53 weight % VOC, but selected a single gas composition of 18 weight % VOC to conduct most of the economic analysis on emission control options. When EPA utilizes this analysis to justify

controls, controls on high VOC content gas will actually have much lower cost/ton of VOC than the average, while controls on low or no VOC in the gas will have cost effectiveness that will approach an infinite cost/ton. (See Section 5.1.2 for further details). It is clearly inappropriate to designate an emission control for the reduction of VOC as BSER for a gas that contains no VOC, but this is what EPA has done by utilizing a one-size-fits-all economic strategy.

However, it is not fair to say that EPA did not attempt to set minimum thresholds where controls are cost effective. EPA set two throughput volume thresholds (20 bbl/day for crude oil and 1 bbl/day for condensate) for storage vessels. EPA selected the two throughput thresholds using a flawed study (see Section 16.6.1.) that assumed the emissions rate is dependent upon throughput volume alone. However, as discussed in Section 16 the composition of the hydrocarbon liquid and the temperature and pressure of the production separator also have a significant impact on VOC emissions. In fact, all three of these must be known to determine the VOC flash emissions from a storage vessel. API believes that throughput alone is an inappropriate surrogate to assure that emissions controls are economical, and that only VOC flash emissions calculations can serve this function for the production sector. However, API has suggested an alternative to a throughput threshold that is based on conservative volatile condensate compositions, conservative separator temperature and a range of separator pressures. (See Tables 16-3, 16-4, and 16-5 in Section 16.6 for cost effectiveness calculations).

Each new emission control suffers from this one-size-fits-all economic justification concern. All of the emission controls proposed are occasionally cost effective in selected O&G operations. However, all of the proposed emission control options fail to be cost effective in other O&G operations. A consistent theme of API's comments is that the controls should be applied only in situations where they are economic, so it qualifies as BSER.

4.3. Completeness of Cost Estimations of Control Options

In most cases, the cost estimates that EPA provides for specific pieces of equipment appear reasonable for the central activity. However, in every case the items included in the economic analysis are incomplete and the costs for compliance assurance requirements of the rule are underestimated. Below are listed examples of cost that have been left out or underestimated.

- **Auxiliary Equipment Required for a Complete Control System.** EPA consistently included the primary equipment required for the control option being considered. However, often the cost of auxiliary equipment was overlooked. For example with storage vessels, EPA considered the cost of the control device (flare, combustor or VRU), but did not appear to include the closed vent system required to collect the vapors, assure condensed liquids do not "vapor lock" this very low pressure system, and separate any condensed liquids before it reaches the control device.
- **Monitoring Requirements.** EPA appeared to include some costs for monitoring where required (i.e. storage vessels and LDAR). However, this cost did not appear to consider the remote, dispersed and unmanned nature of the facilities. This is most evident in the CPMS flow monitoring requirements for storage vessels. The data quality standards for CPMS require that personnel be able to monitor the instrumentation on an hourly (or at least daily) basis. Since these sites are unmanned, remote data collection systems would be required that are typically

either totally unavailable or require expansion to meet the requirements. These costs often far exceed the cost of control equipment that data is being provided for. Additionally, the operational personnel that are routinely at production sites are not qualified to perform many of the tasks required by the proposed rule and may be required multiple times a month. Travel time to and from the site is typically averages an hour in each direction from the central office. These costs have not been included in the economic analysis.

- **Notification, Recordkeeping and Reporting Cost.** EPA appears to assume that the data required for notification, recordkeeping and reporting required by the rule is readily available in a central location or in coordination with other routine operations. This is an unrealistic assumption.

4.4. Cost Effectiveness Threshold

When deciding whether emissions controls are economically justified, some measure is required, typically a cost/ton of emissions reduced. EPA has not placed a numeric threshold on the cost/ton of pollutant reduced, preferring to leave that decision up to a case-by-case analysis. However, comparing the cost effectiveness numbers for the control strategies that were determined not to be BSER with those that were accepted as BSER gives a good representation of an appropriate threshold. The cost effectiveness decisions that EPA made in determining regulatory strategies for this proposed rule were extracted from the Technical Support Document (EPA-HQ-OAR-0505-0045). From this table a cost effectiveness of less than \$5,000/ ton of VOC reduced appears to be acceptable.

Table 4-1. Comparison of EPA Cost Effectiveness Decisions

Emission Source Type	Control Option	VOC Cost Effectiveness (\$/ton)	EPA Decision
Pneumatic Devices	Low Bleed	\$262	Accepted
Centrifugal Compressors - Production	Dry Seals	\$595	Accepted
Completions/Flowback	REC	\$1,516	Accepted
Pneumatic Devices	Compressed Air	\$2,659	Accepted
Storage Tanks	95% Control with VRU	\$3,150	Accepted
Equipment Leaks - Processing Plants	VVa LDAR	\$3,352	Accepted
Centrifugal Compressors - Transmission	Dry Seals	\$3,495	Accepted
Reciprocating Compressors - Other	Change Out Seals	\$3,700	Accepted
Centrifugal Compressors - Production	Flare	\$5,300	Rejected
Equipment Leaks - Well pads	VVa LDAR with AWP	\$5,364	Rejected
Equipment Leaks - Gathering Boosting	Component VVa LDAR	\$6,079	Rejected
Equipment Leaks - Well pads	VVa LDAR	\$6,934	Rejected
Equipment Leaks - Gathering Boosting	VVa LDAR	\$8,174	Rejected
Equipment Leaks - Gathering Boosting	VVa LDAR with AWP	\$8,685	Rejected
Equipment Leaks - Well pads	Component VVa LDAR	\$15,063	Rejected
Equipment Leaks - Transmission Storage	VVa LDAR with AWP	\$19,723	Rejected
Equipment Leaks - Transmission Storage	VVa LDAR	\$19,769	Rejected
Equipment Leaks - Transmission Storage	Component VVa LDAR	\$24,762	Rejected
Centrifugal Compressors - Transmission	Flare	\$31,000	Rejected
Reciprocating Compressors - Wellhead	Change Out Seals	\$84,000	Rejected

5. APPLICABILITY [NSPS OOOO]

The scope of the regulation should be defined in the applicability §60.5365, so that all stakeholders clearly know what is covered. This regulation like many others has expansion or limitations of the scope included in definitions, paragraph titles and other portions of the rule. API recommends the following changes be made to the applicability section of the rule.

5.1. Applicability to Low VOC Natural Gas Streams

In the summary of the proposed rule, EPA states that it is adding new source performance standards for VOCs. However, there are insufficient conditions in the proposed rule to limit the applicability to streams that have a significant quantity of VOC, resulting in a NSPS regulation that can be interpreted to apply to streams with no VOCs. In this proposed rule, the term “natural gas” is used in the titles of the category, plants and equipment descriptions, as well as a surrogate for VOCs. However, many natural gas streams are mainly methane and have little or no VOC content when it is produced from the reservoir (thus the terms “dry gas” and “coal bed methane” that are common in the industry). EPA has previously stated that it does not intend to regulate GHGs within this rule and thus has not provided the public with an opportunity to comment on the inclusion of methane. Without some minimum applicability threshold for VOCs, EPA is essentially regulating GHGs.

5.1.1. Natural Gas is not an Appropriate Surrogate for VOCs

A common thread running through the virtually all of the Subpart OOOO proposal is that natural gas can appropriately be assumed to have a fixed composition. EPA does recognize that produced gas typically has significantly different characteristics than gas being moved through transmission operations, and thus established different fixed compositions for production (*i.e.*, completions and recompletions) and transmission (*i.e.*, pneumatics, equipment leaks, compressors). See Memorandum from Heather P. Brown, PE, EC/R Inc., to Bruce Moore, EPA/OAQPS/SPPD, Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking (July 28, 2011) (“EC/R Memo”). However, these compositions are the only compositions used for purposes of analyzing the regulatory alternatives and supporting the proposed rule. In addition, EPA would require applicability to effectively be based on these fixed-composition assumptions. In other words, the actual content of the natural gas produced or transmitted at an affected facility has no bearing on applicability of the rule – applicability is based solely on the act of producing, processing, or transporting natural gas.

This approach of assuming geographically, temporally, and geologically fixed compositions of VOCs and other regulated pollutants in natural gas is insupportable and arbitrary. EPA's own analysis demonstrates the problem. Table 7 of the EC/R Memo provides a sensitivity analysis of EPA's gas composition data for gas wells and hydraulically fractured wells (see EC/R Memo, page 10). This table shows that the minimum VOC content in EPA's database is 0 and the maximum is 29.6 volume percent. This means that certain “affected facilities” will be subject to the rule even though the gas they handle contains little or no VOCs, which is the pollutant ostensibly, being regulated by this rule (see Section 5.1.2 for further details

EPA acknowledges that this is a problem. In discussing the proposed standards for well completions, EPA notes that “gas composition” is one of the “variety of factors” that determine “the length of the flowback period and actual volume of emissions.” 76 Fed. Reg. at 52757. As a result, EPA admits that “[t]his variability means there will be some wells which emit more than the estimated emission factor and some wells that emit less.” More to the point, this “heterogeneity in well operations and costs” means that “while RECS may be cost-effective on average, they may not be for all operators.” *Id.* at 52758.

However, EPA fails to take this observation to its logical conclusion – that some wells will emit so little VOC that the proposed standards cannot be justified given that little or no reductions will be achieved in regulated pollutant emissions and the cost effectiveness of the proposed standards would be unreasonably high. Instead, EPA sets up a false choice – that EPA can either “require an operational standard” (such as the proposed REC requirement) or impose a “performance-based standard” (which is not defined, but in context appears to be some sort of numeric emissions limitation). EPA asserts that a performance standard cannot work “because we believe there are no feasible ways for operators to measure emissions with enough certainty to demonstrate compliance with a performance-based standard.” *Id.* Therefore, EPA decided to propose an “operational standard” applicable to all hydraulically fractured natural gas wells.

This makes no sense because EPA obviously has other regulatory alternatives. These include the possibility of setting a lower level VOC cut-off for natural gas that would target the proposed rule only on those who produce, process, or transport gas with more than a specified amount of VOCs (with the cut-off based on consideration of emissions reductions and costs). EPA's failure to consider such other approaches is arbitrary and capricious. And, its proposal to impose requirements that “may be cost-effective on average” but that “may not be [cost effective] for all operators” violates the Agency's obligation to “consider the representativeness of the test data relied upon in the development and justification of its standard.” *National Lime* at 451.

Notably, in the NESHAP part of the proposal, EPA abandons the fixed composition assumption in assessing control requirements for small dehydrators “due to variability of gas throughput and *inlet gas composition*.” *Id.* at 52768 (emphasis added). As a result, this element of the proposed rule is based on facility-specific data of “inlet natural gas BTEX concentration.” *Id.* This further demonstrates that EPA can and should take account of VOC content in determining the applicability of Subpart OOOO.

On a related note, the variability in the composition of natural gas also means that natural gas is not an appropriate surrogate for VOCs under the standard for pneumatic devices. *See id.* at 52800 (proposed §60.5390). The D.C. Circuit has made clear that EPA does have authority to regulate surrogate pollutants, but “only if it is reasonable to do so.” *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) (internal quotes and citations omitted). For the reasons discussed above, applying the pneumatic device standards to any device in natural gas service would cause the standard to apply to many devices that emit little or essentially no VOCs. As a result, natural gas is not an appropriate surrogate for VOCs because applicability of the rule is not reasonably focused on significant sources of VOCs.

Lastly, the proposed rule does – in a limited way – provide for a lower level VOC cutoff. Section 60.5430 defines “equipment” to include only components “in VOC service” and §60.5400 provides that compressors at onshore natural gas processing plants are covered only if they are “in VOC service.” 76 Fed. Reg. at 52809 (proposed definition of “equipment”; 52800 (proposed VOC standards for onshore natural gas processing plants). However, proposed §60.5400(f) requires that “[e]ach piece of equipment is *presumed* to be in VOC service ... unless an owner or operator demonstrates that the piece of equipment is not in VOC service.” *Id.* at 52801 (emphasis added). This presumption can be overcome

only if it is “determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight.” *Id.*

While a lower level VOC cutoff is appropriate and necessary (for the reasons discussed above), EPA is without authority to require that affected equipment and compressors must be assumed to be in VOC service unless it is proven that they are not. NSPSs apply to specified affected sources – in this case, equipment and compressors with the potential to emit VOCs in amounts that justify regulation. It is unreasonable and arbitrary for EPA to declare that equipment or compressors are covered by the rule when it has not been determined that the equipment or compressors handle gas of a composition that EPA has determined warrants regulation.

5.1.2. In VOC Service and In Wet Gas Service

API requests that EPA add a limitation to §60.5365 that this regulation applies only to streams that are “in VOC service” or “in Wet gas service” as discussed further below.

EPA has chosen to use average compositions of natural gas throughout the US and utilized a single average composition with VOC content of 18.28% by wt. to economically justify regulations for LDAR, natural gas compressors, and pneumatic controllers throughout the US (see EPA-HQ-OAR-0505-0084). This “one size fits all” approach ignores the fact that natural gas ranges in VOC content from 52.72% to 0.0% by wt for the gas compositions EPA listed in the docket. In fact the average VOC content for shale gas production, the fastest growing sector of the natural gas industry, is only 2.95% by wt. and the average VOC content is 2.35% by wt. for the natural gas transportation sector. In Attachment G, RIA Review for Completions, Table G-6, API has calculated the cost effectiveness for the compositions EPA included in the docket for determining an “average natural gas stream”. The cost effectiveness (in terms of \$/ton of VOC) was calculated to be \$4,814/ton at 17.95 wt % VOC, \$8,564 at 10.09 wt % VOC and \$16,552/ton at 4.81 wt % VOC. This means that the cost benefit approaches infinite \$/ton of VOC for gas with no VOC content (i.e. coal bed methane [CBM] and some of the shale gas fields). When compared to the other cost effectiveness decisions that EPA made in determining regulatory strategies in the Technical Support Document (EPA-HQ-OAR-0505-0045; see Section 4.4), restricting these regulations to streams “in VOC service”, as recommended below, seems very reasonable.

NSPS Subparts VV and GGG control equipment leaks for streams containing 10% or more VOC by weight, and API continues to believe that 10 % by weight of VOC is an appropriate threshold for the oil and natural gas production sector. However, when EPA promulgated NSPS Subpart KKK in the 1980s, EPA also decided to control streams in “wet gas” service. While historically most streams in “wet gas” service contained significant amounts of VOC, that is not the case today. Today, two “wet gas” streams commonly occur that were infrequent or non-existent when NSPS Subpart KKK was promulgated. The first is streams with high inert gas (carbon dioxide [CO₂] or nitrogen [N₂]) content from enhanced oil recovery gas flood projects. The inert gas content often becomes the majority of the “wet gas” stream and the VOC content becomes negligible. The wet gas is still processed at a natural gas processing plant, to remove the inert gas stream (typically recycled for enhanced oil recovery purposes) and natural gas liquids (NGLs) to make the remaining natural gas

salable. The second is non-conventional natural gas (coal bed methane [CBM], shale gas or tight sands) that may have little VOC content. These new low VOC content streams were not considered in the original Subpart KKK promulgation process.

API recommends that EPA retain consistency between the LDAR programs (i.e., Subparts VV, GGG and KKK). API proposes that EPA add a definition of "in VOC service" to Subpart OOOO, and use that term in the applicability provisions (See Section 19.4.2 for further information).

Suggested Rule Text:

§60.5365

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5400

This section applies to each compressor in VOC service ~~or in wet gas service~~ and the group of all equipment (as defined in §60.5430), except compressors, within a process unit.

* * * * *

(f) You must use the following provision instead of §60.485a(d)(1):

Each piece of equipment is presumed to be in VOC service ~~or in wet gas service~~ unless an owner or operator demonstrates that the piece of equipment is not in VOC service ~~or in wet gas service~~. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. ~~For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process.~~ For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-63, 77, or 93, E168-67, 77, or 92, or E260-73, 91, or 96 (incorporated by reference as specified in §60.17) must be used.

§60.5430

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service ~~or in wet gas service~~, and any device or system required by this subpart.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

However, if EPA continues to believe it is important to regulate “wet gas” streams that are not “in VOC service”, API believes EPA must still set a minimum VOC content and maximum inert gas content for “wet gas”. Without doing so, EPA is ignoring the important part that VOC content in the controlled stream plays in the cost effectiveness of its regulations. API realizes that setting a concentration below the current 10 wt % “in VOC service” threshold is somewhat arbitrary, since this is not considered cost effective as discussed above. However, API proposes that EPA set the wet gas threshold (X) no lower than 5% by weight VOC. Additionally, API recommends EPA exclude “wet gas” that is predominately (i.e. greater than 50 wt %) inert gases. Therefore, API recommends the following:

Alternative Suggested Rule Text:

§60.5365

If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. Paragraphs §60.5365(a)-(e) apply only to affected facilities *in VOC service or in wet gas service.* ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

§60.5430

In wet gas service means that a compressor or piece of equipment contains or contacts wet gas. ~~the field gas before the extraction step at a gas processing plant process unit.~~

Wet gas means field gas before the extraction step at a gas processing plant process unit that is >X% VOC by weight. Wet gas does not include gas streams that are >50% by weight inert gases (nitrogen or carbon dioxide).

[API recommends X be equal to or greater than 5]

5.2. Applicability to Liquid Streams

The regulatory analysis on liquid streams in storage vessels has obviously concentrated on crude oil and condensate from production wells, however nothing in this Subpart limits the applicability to these streams. Regulators could easily apply the storage vessel regulations to vessels storing chemicals, vehicle fuels, lubrication oils, produced water, etc.; however these storage vessels have not gone through the economic analysis necessary to justify the applicability of the proposed rule to these services. API requests that applicability of the rule to storage vessels, as specified at

§60.5365(e), be limited to condensate and crude oil liquid streams. See Sections 16.4 and 16.5 for further details.

5.3. Applicability Limitation to Sectors

Applicability paragraphs §60.5365 (d) & (e) for pneumatic controllers and storage vessels have no limitation on the range of facilities to which they apply. Thus, the standards could inappropriately be applied to a fuel tank in a residence, if you ignore the title of the Subpart. Even with that limitation, a pneumatic device on the fuel system of any commercial boiler could be considered to be regulated, since the ending of the distribution sector was never discussed in the proposed rule. API requests that EPA add text to §60.5365 that limits applicability to the oil and natural gas production sector.

5.4. Applicability to Wellheads and Reduced Emission Completion Operations

5.4.1. Affected Facility

EPA's proposal to regulate temporary construction emissions from well completion activities within an NSPS has created problems and confusion within the proposed regulatory text. As discussed in Section 2.4, construction emissions are not part of normal operations and have not been regulated previously within an NSPS. Additionally, the CAA authority for NSPS applies to "any building, structure, facility, or installation." Thus, EPA chose the only stationary physical structure available at the time a well completion is performed as the "affected facility," the wellhead. API is concerned that EPA's choice of the wellhead as the affected facility along with EPA's failure to accurately define the emissions regulated by the proposed rule will lead to confusion within the agency and industry for the life of Subpart OOOO. EPA should first clarify that the affected facility is a natural gas wellhead facility onshore "except for one that does not have flowback immediately following hydraulic fracturing stimulation."

5.4.2. Regulated Emissions

The emissions proposed to be regulated by the proposed rule come from the flowback immediately following hydraulic fracturing stimulation. Such flowback, post hydraulic fracture stimulation may occur in conjunction with new well completion, existing well recompletion, or workovers. However, the proposed rule regulates "each well completion operation with hydraulic fracturing." Well completion, as discussed in Section 15.8, means the process of making a new oil or natural gas well ready for production. It allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics and also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture stimulate and prop open new fractures in lower permeability reservoirs. Flowback is only a portion of the well completion operation with hydraulic fracturing stimulation. Flowback can also occur from a recompletion or workover with hydraulic fracturing stimulation. VOC air emissions only occur when there is gas containing VOCs in the flowback. Well completions, recompletions, and workovers are not directly associated with the emissions being regulated. API believes that well completions,

recompletions, and workovers should only be included in the definition of flowback to prevent confusion of what is being regulated.

5.4.3. Defining Applicability

The applicability of the proposed regulation to “flowback immediately following hydraulic fracturing stimulation at onshore gas wellhead facilities” should be clearly defined in §60.5365(a). Furthermore, as discussed in Section 15.6.1, API believes that the following portion of the text is unnecessary and should be eliminated.

“For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.”

However, API agrees that the text should clarify that other equipment, such as process units, storage vessels, pneumatic controllers, and compressors located at the well site are not affected by hydraulic fracture flowback operations. This text is needed because of the issues discussed in Sections 5.4.1 and 5.4.2 above.

Suggested Rule Text:

§60.5365

If you are the owner or operator of [a site prior to the point of custody transfer at which is located](#) one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. [Paragraphs §60.5365\(a\)-\(e\) apply only to affected facilities in VOC service.](#) ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

- (a) [An onshore natural gas wellhead affected facility](#), is a single natural gas well, ~~that has flowback immediately following hydraulic fracturing stimulation.~~ [VOC emissions from flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore is the only activity regulated at this affected facility. For the purposes of this subpart, an existing onshore natural gas wellhead facility is considered modified if it meets the criteria of modification in §60.14. The modification of an existing natural gas wellhead affected facility does not affect the status of other equipment, process units, storage vessels, or pneumatic devices located at the well site.](#)

§60.5430

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and

returning the well to production. [Flowback immediately following hydraulic fracture stimulation may occur in conjunction with a well completion, recompletion, or fracture stimulation of the same zone in an existing well.](#)

5.5. Applicability to Sweetening Units

In several locations of the regulatory text, EPA states clearly that the standard applies to sweetening units located at onshore natural gas processing plants. However, this distinction is not made in the applicability provisions of §60.5365(g). Some examples of where EPA clearly states the standard applies only to sweetening units at onshore natural gas processing plants, include:

- In §60.5405, “What standards apply to sweetening units at onshore natural gas processing plants?”
- In §60.5406, “What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?”
- In §60.5407, “What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?”

Based on the examples above, API reviewed and commented on the proposed rule with the understanding that the requirements for sweetening units apply only to units located at onshore natural gas processing plants. In order to improve clarity on the applicability for sweetening units, API recommends the following revisions:

Suggested Rule Text:

§60.5365

(g) Sweetening units located [at onshore natural gas processing plants](#) that process natural gas produced from either onshore or offshore wells.

5.6. Applicability Limitations to Modification and Reconstruction

EPA needs to clarify the applicability of Subpart OOOO to equipment that could be considered modified or reconstructed. EPA appears to inappropriately apply the modification or reconstruction tests to capture some existing facilities (i.e., recompletions and compressor relocations) for regulation when the General Provisions tests would not have included them and such inclusion is in violation of the Clean Air Act provisions. Other low cost, component level affected facilities (i.e., pneumatic controllers) may technically undergo modifications and reconstruction per the text of the General Provisions, but not fit the intent of the original rulemaking.

API believes that including definition of modification in Subpart OOOO is unnecessary, adds confusion and improperly changes longstanding precedents that reflect the intent of Section 111 of the Clean Air Act. API recommends that the provisions of §60.14 continue to apply to all NSPS regulations, including Subpart OOOO.

Suggested Rule Text:**§60.5430**Preferred Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

5.6.1. Relocated Compressors

The provisions of §60.5365(b) & (c) states that a “compressor is considered to have commenced construction on the date the compressor is installed at the facility.”

This violates, for no apparent reason, the §60.2 definition of “commenced”, which is “Commenced means, with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.” Under this definition, which is long established in Part 60 precedent, construction of a compressor occurs when the contractual obligation has been entered to purchase the compressor or for the project that purchases and installs the compressor.

In addition, this proposed language could be interpreted to mean that a compressor that has been relocated from one location to another is “new” (see Section 18.1). This is directly opposed to the provisions of §60.14(e)(6) that state “The relocation or change in ownership of an existing facility” by itself shall not be considered a modification. This same precedent has been followed in the NESHAP regulations where the relocation of an affected source does not affect the existing status of the source (see Background Information for Promulgated Standards for the final NESHAP General Provisions (EPA-453/R-02-002), page 3-62). Not following this precedent would lead to the illogical result that if an existing engine (regulated by either NSPS Subparts JJJJ or IIII or NESHAP Subpart ZZZZ) and compressor (regulated by the proposed NSPS Subpart OOOO) package was relocated, the engine would still be considered existing, but the compressor would be considered new. Additionally, for a new compressor package, two notices of construction would be required at different times, one for when the engine is ordered as required by Subpart JJJJ, and a second for when the compressor is installed. Other issues arise with the undefined phrase

“installed at the facility”. API requests that the last sentence of both §60.5365(b)&(c) be removed to resolve this issue.

5.6.2. Reduced Emission Completions

The proposed rule would define “modification” to include “each recompletion of a fractured or refractured existing gas well.” 76 Fed. Reg. at 52810 (definition of “modification” in proposed §60.5430). As a result, recompletion of an existing non-affected well would cause Subpart OOOO to apply to that well. This requirement is unfounded and unlawful.

EPA asserts “a completion associated with refracturing performed at an existing well” would be a modification “because a physical change occurs to the existing well resulting in emissions increase during the refracturing and completion operation.” *Id.* at 52745. More specifically, the “physical change, in this case, would be caused by the reperforation of the casing and tubing, along with the refracturing of the wellbore.” *Id.* at 52759. Additionally, the “increased “VOC emissions would occur during the flowback period following the fracturing or refracturing operation.” *Id.* While EPA asserts in the preamble that “a detailed discussion of this determination is presented in the Technical Support Document,” *id.* at 52745, that “detailed discussion” merely consists of the following:

In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. [TSD at 4-27]

This “detailed discussion” adds nothing of substance to EPA’s recap in the preamble.

The term “modification” is defined in § 111(a)(4) to mean “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” Under this definition, a modification occurs only if two things happen: (1) there must be a “physical change or change in the method of operation”; and (2) the change must result in an emissions increase.

In the context of the New Source Review program, the D.C. Circuit has opined that “Congress’s use of the word “any” in defining a “modification” means that all types of “physical changes” are covered.” *New York v. EPA*, 443 F.3d 880, 890 (D.C. Cir. 2006). In addition, the court determined that “the plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.” *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005).

However, the Supreme Court concluded that the § 111 definition of modification – which is

cross referenced in the statutory PSD provisions and, thus, applied in both the NSPS and NSR programs – does not have to have the same meaning under both programs. *Environmental Defense v. Duke Energy Corp.*, 127 S.Ct. 1423, 1434 (2007) (“Nothing in the text or the legislative history of the technical amendments that added the cross-reference to NSPS suggests that Congress had details of regulatory implementation in mind when it imposed PSD requirements on modified sources; the cross-reference alone is certainly no unambiguous congressional code for eliminating the customary agency discretion to resolve questions about a statutory definition by looking to the surroundings of the defined term, where it occurs.”). Thus, EPA has latitude within the context of § 111 to implement different rules regarding modifications – and, indeed, has done so from the inception of the NSPS program in the early 1970s.

In particular, EPA's regulatory definition of “modification” under the NSPS program provides several categories of activities that “shall not, by themselves, be considered modifications under this part.” 40 C.F.R. §60.14(e). Among other things, excluded activities include “maintenance, repair, and replacement which the Administrator determines to be routine for a source category,” and “an increase in production rate that can be accomplished without a capital expenditure.” *Id.* at §60.14(e)(1), (2). The term “capital expenditure” is defined to mean “an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of the Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code.” *Id.* at §60.2. These provisions have been included in the rules since the very beginning of the NSPS program in 1971. They reflect the fact that Congress established the NSPS program for “new” sources. Without these exclusions, even the most minor activities would convert an existing source into a “new source.” The premise behind characterizing these activities as not being “changes” is that they all contemplate that the plant will continue to be operated in a manner consistent with its original design and thus is not a “new” facility.

In addition, EPA has established a method of measuring emissions increases under the NSPS program that differs markedly from the approach used under the NSR program. Under §60.14(b), the emission rate must be expressed as kg/hr of any pollutant to which the standard is applicable. The rule specifies that emissions factors should be used, unless the Administrator determines the use of such factors will not clearly demonstrate that emissions will increase or decrease as a result of a change. In this case, material balances, continuous monitoring data, or manual emissions test may be used. Testing must be conducted under conditions based on representative performance of the facility. And, all operating parameters that may affect emissions must be held constant to the maximum feasible degree.

To be sure, EPA has authority to adopt rule-specific modification provisions that differ from these general provisions. *See, e.g., Id.* at §60.14(f) (“Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provision of this section.”). However, EPA clearly has the burden of explaining how such “special provisions” comport with the statute and why such “special provisions” should be adopted in lieu of the general provisions. EPA has failed in both regards with respect to the Subpart OOOO definition of

“modification.”

EPA fails in the proposal to explain why a recompletion is a physical change that should automatically trigger the application of NSPS Subpart OOOO. EPA merely asserts that it is a modification without any explanation or justification on the record. This assertion is particularly unavailing in light of the longstanding routine maintenance and capital expenditure exclusions from the definition of modification. Routine maintenance, for example, is a multifactor analysis that tries to arrive at a “common sense” finding based on the specific facts of a particular affected facility. In Section 15.11, API estimates that there are 1205 completions per year nationwide. These recompletions can certainly vary in nature, extent and cost and should be assessed individually, rather than automatically assumed to be a modification. This failure to explain, in the first instance, why recompletions can not constitute excluded routine maintenance or production increases achieved without a capital expenditure are arbitrary and capricious and represent a critical failure to provide an adequate explanation of “the major legal interpretations ... underlying the proposed rule.” CAA § 307(d)(3)(C).

EPA also fails to provide a rational explanation as to why a recompletion must, in all cases, result in an emissions increase. First, this, assumes that there are actual emissions associated with a recompletion, which for reasons discussed in other parts of these comments, is not a correct assumption. Second, if there are emissions, there may not be an increase. In fact, the emissions estimates in the TSD show that recompletions should not be expected to cause an emissions increase at all. Table 4-2 of the TSD shows that uncontrolled emissions from “natural gas well completion with hydraulic fracturing” are expected to be 158.55 tons of methane, 23.13 tons of VOC, and 1.68 tons of HAP per event (TSD at 4-7). Table 4-2 also reports emissions estimates for the same pollutants for “natural gas well recompletion with hydraulic fracturing.” Notably, EPA presents information that the emissions estimates for recompletions *are exactly the same* as the estimates for completions; however, they are lower unless a new zone is fractured.

Even more fundamentally, EPA's general provisions require emissions to be measured based on the “representative performance of the facility,” with all relevant operating parameters held constant. In other words, an apples-to-apples comparison must be made of pre- and post-change emission rates. This raises two critical questions EPA has not addressed. First, why are emissions from completions relevant to the emissions analysis when it is clear that emissions from completions are not representative of the performance of the facility? As explained above, for the vast majority of its operating lifetime, the only emissions from a well come from fugitive leaks. The initial completion and periodic recompletions certainly are not representative of normal operations and, therefore, emission rates during these periods should not be used to characterize emissions from the wells.

Second, even if emissions from completions and recompletions are relevant to the NSPS modification analysis, an “apples-to-apples” analysis should be done – *i.e.*, the emission rate during a recompletion should be compared to the emission rate during the initial completion to determine whether the recompletion results in an increase in emission rate. As shown above, because EPA has determined that emissions from recompletions are the same as

emissions from completions, there can be no emissions increase attributed to recompletions. EPA's failure to investigate and explain its departure from these key aspects of the §60.14 definition of "modification" render the proposal arbitrary and violate EPA's obligations under § 307(d)(3)(C).

5.6.3. Leak Detection and Repair (LDAR).

LDAR process units often use the concept of "capital expenditure" to prevent the addition of a few minor components from triggering modification. API believes that EPA needs to clarify the meaning of "capital expenditure" for the purposes of NSPS Subpart OOOO. A detailed discussion of "capital expenditure" can be found in Section 19.4.4.

6. DEFINITIONS [NSPS OOOO]

Confusion has occurred in the past when definitions have been used to both describe the meaning of the term for clarity and additionally limit applicability of the regulation. While this is often convenient and efficient in terms of creating regulatory text, it can cause unintended consequences. The definitions suggested below have attempted to keep the definition restricted to the meaning of the term, if that term is used within industry. Some terms are unique to EPA regulations, such as "in VOC service". In these instances, efforts have made to be consistent with other regulations, to reduce confusion.

6.1. Petroleum Product Definitions

The definitions of "crude oil" and "condensate" should not be based on API Gravity; the difference in these two products is in their origin. Physical properties of the products overlap and are not good indicators of product type. Also, natural gas was an undefined term and should be clarified.

Suggested Rule Text:

§60.5430

Condensate. *Condensate* means a ~~hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in §60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate~~ natural gas liquid recovered from associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60 degrees Fahrenheit.
[Definition from Energy Information Administration glossary]

Crude Oil. *Crude oil* means ~~crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.~~ a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- [Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well \(casinghead\) gas in lease separators, and that subsequently are commingled with the crude stream without being separately measured.](#)
- [Small amounts of non-hydrocarbons produced with the oil.](#)
[Definition from Energy Information Administration glossary]

Natural Gas. [Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. LNG is not considered natural gas, since impurities such as VOCs and HAPs have been removed.](#)

[Basis of definition is NSPS Subpart Da]

6.2. Low VOC Streams

The definitions below should be added or modified as discussed in Section 5.1.2. The "In VOC service" definition is needed, even though it is in the definitions section of NSPS Subpart VVa, because that section of NSPS Subpart VVa is not referenced from Subpart OOOO.

Suggested Rule Text:

§60.5430

In VOC Service. [In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.](#)

[Copied from NSPS Subpart VVa]

In Wet Gas Service. *In wet gas service* means that a compressor or piece of equipment contains or contacts [wet gas.](#) ~~the field gas before the extraction step at a gas processing plant process unit.~~

Wet Gas. [Wet gas means field gas before the extraction step at a gas processing plant process unit that is >X% VOC by weight. Wet gas does not include gas streams that are >50% by weight inert gases \(nitrogen or carbon dioxide\).](#)

[API recommends X be equal to or greater than 5; see Section 5.1.2]

6.3. Natural Gas Processing Plant

The term "natural gas processing plant" is important to the Equipment Leaks, Acid Gas Recovery, and Pneumatic Controllers Sections. The definition of "natural gas processing plant" should be revised to add "forced" before extraction to clarify which extraction processes are included. See Section 19.4.1 for additional details.

Suggested Rule Text:

§60.5430

Forced Extraction. *Forced extraction of natural gas liquids* means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids or fuel treatment skids.

[based on EPA's proposed definition in *Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule* (76 FR 56050)]

Natural Gas Processing Plant. *Natural gas processing plant (gas plant)* means any processing site engaged in the forced extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

6.4. Modification

EPA should not redefine the term "modification" in Subpart OOOO. The definition of modification in §60.14 of NSPS General Provisions should apply to Subpart OOOO.

It is unnecessary and confusing to include increases in emissions of both VOCs and natural gas in the proposed definition of modification. On 76 FR 52756, EPA states "this proposed rule does not include standards for regulating the GHG emissions." Including natural gas in the definition of modification, without defining it as requested in Section 4.1, will result in regulation of natural gas streams that have little or no VOCs, such as coal bed methane.

As discussed in Section 5.6, EPA should rely on the Part 60 General Provisions for defining modification. However, if EPA chooses to define modification in this subpart, the references to natural gas and recompletions should be removed.

Suggested Rule Text:

§60.5430

Preferred Option:

~~*Modification* means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC ~~or natural gas~~ emitted into the atmosphere by that

facility or which results in the emission of VOC ~~or natural gas~~ into the atmosphere not previously emitted. ~~For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

6.5. Orphaned Definitions

EPA has defined the terms “pneumatic pump”, “plunger lift system”, “reduced emissions completions”, and “reduced emissions recompletion”. None of these terms are used anywhere in the proposed rule. These definitions should be eliminated.

7. COMPLIANCE DATE

The compliance date of the final rules should be delayed because of the following:

7.1. Congressional Review Act

The Congressional Review Act states that a major rule shall become effective 60 days after publication in the Federal Register (see 5 USC 801(a)(3)(A)(i); unless other processes take longer). 5 USC 804(2)(A) states that a major rule is one that has “an annual effect on the economy of \$100,000,000 or more”. EPA states that “this action is an “economically significant regulatory action” because it is likely to have an annual effect on the economy of \$100 million or more (see 76 FR 52794). Thus, the compliance dates of the final rule need to be extended to at least the effective date (60 days after the publication in the Federal Register) to comply with the Congressional Review Act.

7.2. NSPS Effective Date for Completions

42 USC 7411(a)(2) defines new sources as those commencing construction after the proposal date of the performance standard. Currently, the proposed rule triggers compliance on the date of publication of the final rule in the Federal Register. However, an unintended consequence of defining temporary/construction/maintenance activities as affected facilities (see Section 2.4) is that flowback immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore commencing after August 23, 2011 will be defined as new affected facilities, but may be completed before the effective date of the rule. Some regulatory text makes it appear that compliance activities must be completed before the effective date of the rule (i.e., the control requirements of §60.5375 and the notification and recordkeeping requirement of §60.5420(a)(2) and (b)(2) respectively). The rule, of course, cannot impose requirements prior to its effective date. Moreover, it is not possible to impose, upon the effective date of the rule, control measures on activities that have been completed prior to the effective date of the rule.

This retroactive compliance was stated to not be intended by EPA personnel in conference calls and meetings. This intent needs to be made clear in the final rule text. Please see Section 15.5 of the completion section for more details.

7.3. Manufacturer Compliance

The compliance requirements for certain affected facilities (i.e., pneumatic controllers and vapor combustors for controlling storage vessels) are a part of the equipment design that is controlled by

the equipment manufacturer, not the owner/operator. It is difficult for the owner/operator to be assured that he is meeting the requirements of the regulation with the equipment he purchases and installs, unless EPA allows sufficient time for the manufacturer to review the equipment design and label it as complying with the regulatory requirements of this rule.

For example, there are currently few if any manufacturer "guarantees" that continuous bleed pneumatic controllers are "low bleed" as required by proposed §60.5410(d)(3). Additionally, there are few if any continuous bleed pneumatic controllers that are even capable of a bleed rate of less than six scfh under all operating conditions. Variability in operating conditions, such as increases in instrument gas supply pressure, complicates the ability of a manufacturer to guarantee continuous bleed pneumatic controller performance.

NSPS Subpart JJJJ recognized that the manufacturers needed time to design, certify and manufacture equipment, and thus required compliance only for new sources manufactured after given manufacture dates when that equipment could reasonably be available from the manufacturer in quantities to meet the demand.

The same type of allowance provided for in NSPS JJJJ is needed in Subpart OOOO. Thus, while API believes a design verification is more appropriate for pneumatic controllers than a guarantee, we recommend that any equipment design guarantee required for pneumatic controller manufacturers be delayed by two years from the effective date of the rule. For additional discussion of the "guarantee" issue for pneumatics, please refer to Section 17.10.

A similar scenario exists for the option to have the performance test of a control device conducted by the manufacturer. The requirements in NSPS OOOO for storage tank control devices cite the performance test requirements specified in §63.772(e) of NESHAP HH, which include a provision for the performance test to be conducted by the manufacturer as specified in §63.772(h). It will obviously require considerable lead time, however, before such "manufacturer certified" control devices are readily available. We request that the effective date of the storage tank requirements under NSPS OOOO be delayed for 3 years to allow time for the specified control devices to become available.

7.4. Availability of Equipment for Reduced Emissions Completions

The equipment required for Reduced Emission Completions (REC) is not "off the shelf" equipment, but is typically custom built by the owner/operator or service company to meet the anticipated reservoir properties. Additionally, service companies would have to hire and train sufficient personnel to operate the REC equipment to meet the regulatory requirements. EPA should specify a compliance period for implementing the REC requirements that realistically accounts for the limitations on availability of equipment and trained personnel needed for widespread use of REC. Please see Section 15.4 for more detailed information, and for specific recommendations on revisions to the regulatory language. Such a compliance period is well within EPA's authority and, under the circumstances, the REC requirement cannot be justified without it.

By defining each new well as an affected facility, the proposal would cause the requirement to implement RECs to become effective industry-wide upon the effective date of the final rule. As described in Section 15.4, this means that 1,300 sets of equipment would be needed to accommodate

without unreasonable delay the expected number of affected completions. Only 300 sets of equipment currently exist in the industry, which is far short of what would be needed under the proposed rule. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. As a result, as proposed, the REC requirement simply cannot be implemented upon the effective date of the final rule without causing widespread delays in new well development and imposing the substantial business interruption costs associated with such delays.

This means that the proposed requirement to implement RECs immediately upon the effective date of the final rule does not constitute "the best system for emission reduction" (BSER) for three independent reasons. First, § 111(a)(1) requires that BSER must be "achievable." This requirement is not satisfied when the selected control measures (in this case RECs) are not available to a significant portion of affected facilities. Second, § 111(a)(1) requires that BSER must have been "adequately demonstrated." Implicit in this obligation is that the given control measure not only has been shown to be effective in controlling emissions from the given affected facility, but also that it is sufficiently available that it can be obtained and applied by all affected facilities that trigger the control requirement. In this respect, the REC requirement has not been adequately demonstrated. Third, EPA must demonstrate that BSER is cost effective. EPA has failed to account for the costs of delay in obtaining REC equipment, which renders invalid its determination that RECs constitute BSER.

EPA could easily rectify this problem by bifurcating its BSER determination for well completions such that: (1) BSER is no additional control for a period of two years after the effective date of the final rule; and (2) REC constitutes BSER for well completions beginning two years after the effective date of the final rule. Such an approach would require EPA to adopt a "future effective" BSER determination for well completions. EPA has definitively determined that it has such authority under § 111.

Specifically, the so-called "Clean Air Mercury Rule" ("CAMR") was a § 111 standard that implemented mercury control requirements for power plants in two phases. In adopting this rule, EPA provided a detailed explanation as to why it was authorized under the law to do so:

In *Portland Cement Association v. EPA* (486 F.2d 375) (DC Cir. 1973), the Court rejected the argument that the words "adequately demonstrated" in CAA section 111 meant that the relevant technology already must be in existence and that plants now in existence be able to presently meet the proposed standards. Rather, the CAA's requirement that the degree of emission limitation be "adequately demonstrated" means that a plant now in existence must be able to meet the presently-effective standards for existing units, but that insofar as new plants and future requirements are concerned, section 111 authorizes EPA to "look toward what may fairly be projected for the regulated future, rather than the state-of-the-art at present." The court said:

The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry. 478 F.2d at 629. As there, the question of availability is partially dependent on "lead time," the time in which the technology will have to be available. Since the standards here put into effect will control new plants immediately, as opposed to one or two

years in the future, the latitude of projection is correspondingly narrowed. If actual tests are not relied on, but instead a prediction is made, "its validity as applied to this case rests on the reliability of [the] prediction and the nature of [the] assumptions." (citation omitted).

See also *Lignite Energy Council v. EPA*, 198 F.3d 930 (DC Cir. 1999) (section 111 "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present") (quoting *Portland Cement*). These cases address CAA section 111(b) standards for new sources, where achievement of the standards is mandated on a short-term basis....The cases make clear that while a determination about a technology or performance standard's achievability may not be based on "mere speculation or conjecture," a technology or standard that may not necessarily be considered "adequately demonstrated" at present nonetheless can be considered "adequately demonstrated" for a compliance date in the future.

While CAMR was vacated by the D.C. Circuit, the court did not address the CAMR future effective BSER determinations and the court's decision to overturn the rule was not grounded in any concern about these determinations. Thus, EPA's conclusion that it is authorized to make future effective BSER determinations still stands.

Given that EPA has definitively determined that it has authority to under § 111 to establish such future effective BSER determinations, and in light of the record evidence indicating that sufficient REC equipment will not be available upon the effective date of the final rule but can become available within two years after the effective date of the rule, EPA has ample legal and factual justification to defer the REC requirement.

7.5. Adding Control to Existing Tanks

If an exempt affected storage vessel exceeds the exemption level at some point in the future, the regulation should allow for some period of time after exceeding an exemption level to comply with the control requirements. For example, the additional throughput from bringing on a new well to an affected storage vessel may trigger control requirements for a previously exempt tank. Since the throughput exemption is an annual amount, sources might not know if the exemption was lost until the end of the year. An existing affected storage tank that triggers the control requirements after the effective date of the final rule would then have to meet the control requirements as soon as it no longer meets the exemption, which might not be apparent into; the end of the year. In order to avoid any compliance concerns, an owner/operator may be forced to reduce production to ensure the storage vessel continues to meet the exemption or shutdown production until the storage vessel is modified to meet the control requirements.

API therefore recommends EPA include in the final rule a provision to allow time after exceeding an exemption level to implement controls. The time should be sufficient for designing, ordering, and installing the equipment necessary to meet the control requirements. Although this type of scenario would not be a modification, EPA could use a similar approach used in §60.14(g) and allow 180 days to come into compliance with all the applicable standards. For reference, the language used in §60.14(g):

Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

Furthermore, we recommend proposed §60.5395(a)(1) and (2) be clarified to state that the exemptions are based on calendar year annual averages. A calendar year basis is most appropriate because it avoids surprises from fluctuating operations and minimizes burdens by matching the time period used for emission estimating and other reporting, where tank throughput data is needed.

Suggested Rule Text:

§60.5370

- (a) You must be in compliance with the standards of this subpart no later than **60 days after** the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later except for the provisions of §60.5370(a)(1)-(5) below:
- (1) Compliance with §60.5375 is required beginning [two years after the effective date]. From the [effective date] until [two years after the effective date] comply only with §60.5375(a)(1)(ii).
 - (2) Compliance with §60.5390 is required beginning [one year after the effective date], except for the following
 - (i) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (ii) Compliance with §60.5410(d)(3) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (iii) Compliance with §60.5420(c)(4)(iii) is required (for any new, modified, or reconstructed affected facility) beginning two years after the effective date
 - (3) Compliance with §60.5395 is required beginning [three years after the effective date].
 - (4) If your new or reconstructed process unit equipment is subject to §§60.5400, 60.5401, and 60.5402, you must be in compliance no later than 180 days after startup.
 - (5) If you become subject to §§60.5400, 60.5401 and 60.5402 due to modification under provisions of §60.14, the group of all equipment within that process unit must be in compliance with the work practice provisions of §§60.5400, 60.5401, and 60.5402 of this subpart no later than a year after the modification. If any equipment upgrade is required in order to achieve initial compliance (e.g., pump seal and pressure relief device upgrades), you must complete all equipment upgrades and comply with §§60.5400, 60.5401 and 60.5402 for that equipment no later than three years after the modification.

7.6. Compliance Dates for NESHAP Subparts HH and HHH

NESHAP Subparts HH and HHH have been revised. EPA has made allowances for new compliance dates for specific types of equipment that have new or revised compliance requirements because of the proposed revisions [§63.760(f)(7)-(10)]. However, other proposed revisions do not appear to have new compliance dates associated. This practice may have the unintended consequence that the

new text may be interpreted as having retroactive compliance requirements. The following list illustrates some of these unintended consequences.

7.6.1. Major Source Definition Changes

Changing Subpart HH to include all tanks in lieu of tanks “with the potential of flashing emissions” in the affected source will cause some facilities to become major sources. However, EPA has provided no beginning effective date for this change, has not provided any provisions for existing facilities to come into compliance with the newly applicable regulations, or even adequately made the regulated public aware that they need to recalculate their applicability to major per the new Subpart HH definitions and obtain compliance with major source requirements if necessary. API recommends that, consistent with §63.6(c)(5) of the Part 63 General Provisions, EPA allow such facilities 3 years to obtain compliance with these new requirements. Regulatory text will need to be added to §63.760(f) to add the new compliance time. Regulatory text revisions should also be added in the definitions of “associated equipment” and “major source” to indicate the effective dates of the changes take effect.

LDAR Requirements.

EPA revised the requirements for LDAR monitoring to a leak rate definition of 500 ppm within the text of §63.769(c). In doing so, it is not apparent that regulated facilities have not always been required to meet the 500 ppm leak rate definition. API believes (see Section 19 for further discussion) that EPA must clarify that compliance with the 500 ppm leak rate definition only applies after the compliance date established in this rulemaking.

EPA should allow new or reconstructed facilities 180 days and existing facilities at least a year to implement work practice requirements and 3 years to come into compliance with new requirements requiring investment after the effective date of this rule

7.6.2. SSM Events

The revisions around the SSM events have no start date associated. Without this, agency personnel without the knowledge of the regulatory history could try to enforce the provisions around affirmative defense and SSM events retroactively. If EPA continues with these revisions (see Sections above), regulatory text should be added/revised to make a clear distinction of when these provisions become effective.

7.6.3. Performance Testing

Many of the revisions to the control equipment requirements of §63.771 apply to equipment that is currently required. No provisions have been made to indicate when these requirements were changed. EPA should revise the proposed rule so that the new performance testing requirements apply only to control equipment installed for the purpose of complying with this subpart after the effective date of this rule.

8. NSPS COMPLIANCE REQUIREMENTS (NOTIFICATION, RECORDKEEPING, REPORTING, MONITORING, PERFORMANCE TESTING, AND THIRD PARTY VERIFICATION).

In most instances, EPA has followed the precedent of previous NSPS regulations for the proposed rule. However, this proposed rule is unprecedented in the number of affected facilities it will regulate, the average sizes of the sites, and the remote, dispersed and unmanned nature of these sites. The proposed NSPS imposes considerable administrative burden associated with compliance (permitting, recordkeeping, reporting obligations) including first-time regulation (e.g., triggering minor source NSR "facility" permitting in several states) for minor individual pneumatic controllers.

These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. The proposed NSPS results in unnecessary burden for notifications, monitoring, recordkeeping and reporting without a commensurate benefit.

Implementation concerns, potential rule conflicts (e.g. §60.5 determination of construction or modification, §60.14 modification, §60.15 reconstruction), and issues resulting from selective adoption of the General Provisions (40 CFR 60, Subpart A; see Table 3 of Subpart OOOO) is problematic for the proposed rule and is unnecessarily complicated. API suggests that NSPS Subpart OOOO, Table 3 sections designate that §60.7 – Notifications and Recordkeeping and §60.8 Performance Testing do not apply and that the specific requirements are defined within this final rule.

8.1. Excessive Cost Burden

Defining a very small individual piece of equipment (i.e. component-level) as an affected facility is illogical and defies the common sense definition of "facility". Unnecessary burden for notifications, permitting, reporting and recordkeeping would be introduced without commensurate benefit. For example, regulation by an NSPS has implications under state air quality regulations – e.g., permitting may be mandated. Although Subpart OOOO includes a provision that precludes Title V permitting, many states require permitting of NSPS affected sources. This would incur significant burden from reporting and recordkeeping, and new permitting requirements would result in some states. While EPA may attempt to preclude state rules implementation burdens and costs from consideration, the rule costs incurred from state permit actions are significant, add compliance risk though unnecessary rule complexity, can be estimated, and should not be summarily dismissed, disregarded, or ignored.

In the preamble, EPA "estimate(s) that over 20,000 completions and recompletions annually will be subject to the proposed requirements [76 FR 52747]. These completions and recompletions likely correspond to approximately 100,000 new pneumatic devices, thousands of new storage vessels, and associated new compressors. Each of these will be a new "facility" and the totals provide an indication of the magnitude of the annual industry cost burden for notification, recordkeeping, reporting (initial and on-going annual), permitting, and management activities.

Table 8-1 provides a summary of the myriad of equipment and facility-specific notification, recordkeeping, and reporting requirements and burdens imposed by the proposed rule. This table illustrates the magnitude of effort to track and comply with these requirements and also highlights

potential cost impacts that have not been properly categorized or considered in the cost-benefit portion of the proposed rule.

Table 8-1. Summary of Recordkeeping and Reporting Requirements of Subpart OOOO^B

Proposed Regulatory Provision	Requirement	Applies to:	Due Date:	Start Date:
60.5420(a)(1)	Submit written notification required in 60.7(a)(1)	Construction of all affected facilities except pneumatic controllers	30 days after commencement of construction or reconstruction	8/23/11
	Submit written notification required in 60.7(a)(3)	Startup of all affected facilities except pneumatic controllers	15 days after initial startup	8/23/11
	Submit written notification required by 60.7(a)(4)	Physical or operational change that increase emission rates to any affected facility except pneumatic controllers	60 days prior to the commencement of change or as soon as practicable	8/23/11
60.5410(a)(1); 60.5420(a)(2)	Advance notification of well completion operation; commencement date of well completion; lat/long of well.	Gas wellhead completions and recompletions	30 days <u>prior</u> to commencement of well completion	8/23/11
60.5410(a)(2)	Maintain a daily log for completion including compliance with REC and deviations per 60.5375(b)	Gas wellhead completions and recompletions	Daily during completion operations	8/23/11
60.5410(a)(3); 60.5420(b)(1)-(2)	Initial annual report for wellhead affected facility (company name and address; list of affected facilities; reporting period; list of well completions; deviations; completion logs)	Gas wellhead affected facilities	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(1)	Annual report (company name and address; list of affected facilities; reporting period)	All affected facilities	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5410(c)(1)	Continuously monitor number of hours of operation	Well completions	Annual reporting	8/23/11

^B Start date associated with each requirement is August 23, 2011 except for compressor rod packing hour tracking under 60.5420(c)(3)(i)-(ii) that starts either the date of FR final rule or previous rod packing replacement, whichever is later.

Proposed Regulatory Provision	Requirement	Applies to:	Due Date:	Start Date:
60.5420(b)(2)	For gas wellhead affected facilities, list of well completions, deviations, and completion logs	Gas wellhead affected facilities	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(3)	For centrifugal compressors, documentation that each one is equipped w/ dry seals	Centrifugal compressors	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(4)	For reciprocating compressors, documentation that rod packing is replaced at least every 24,000 hours, cumulative hours of operation as specified	Reciprocating compressors	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(5)	Date, location and mfr specs; reason for high bleeds; documentation that each controller has 0 NG emissions.	Pneumatic controllers installed at PFs	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
	Date, location, mfr specs, mfr guarantee that bleed rate is <6scf/hr,	Pneumatic controllers not installed at PFs	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(6)(i)	For storage vessels with condensate throughput >1 bbl/d and crude oil >21 bbl/d, records required by 63.774(b)(2)-(8)	Storage vessels	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(b)(6)(ii)	For storage vessels with condensate throughput <1 bbl/d and crude oil <21 bbl/d, documentation of throughput	Storage vessels	1 year after initial startup or 1 year after final rule publication, whichever is later; annually thereafter	8/23/11
60.5420(c)	[60.7(f)] Maintain records of continuous monitoring tests, calibrations, maintenance, etc.	All affected facilities	Maintain records	8/23/11
60.5420(c)(1)(i)	Records of each completion operation during the reporting period	Gas wellheads	Maintain records	8/23/11
60.5420(c)(1)(ii)	Records of any deviations in completion operation requirements	Gas wellheads	Maintain records	8/23/11
60.5420(c)(1)(iii)	Logs for completion operations	Gas wellheads	Maintain records	8/23/11

Proposed Regulatory Provision	Requirement	Applies to:	Due Date:	Start Date:
60.5420(c)(1)(iii)(A)	Location of well, duration of flowback, recovery to sales line, combustion, venting; and reasons for venting	Non-delineation wells	Maintain records	8/23/11
60.5420(c)(1)(iii)(B)	For delineation wells, all of the above except for duration of recovery to sales line + record the distance, in miles, to nearest gathering line	Delineation wells	Maintain records	8/23/11
60.5420(c)(2)	Maintain records of type of seal system installed	Centrifugal compressors	Maintain records	8/23/11
60.5420(c)(3)(i)-(ii)	Maintain records of (i) cumulative hours of operations as specified and (ii) date and time of rod packing replacement	Reciprocating compressors	Maintain records	Date of FR final rule or previous rod packing replacement, whichever is later
60.5420(c)(4)(i)	Date, location, and mfr specs for each installed pneumatic controller	All pneumatics	Maintain records	8/23/11
60.5420(c)(4)(ii)	Use of high bleed pneumatic is predicated and why	High bleed pneumatics	Maintain records	8/23/11
60.5420(c)(4)(iii)	Mfr's guarantee that emissions are <6scf/hr	Pneumatics not at PFs	Maintain records	8/23/11
60.5420(c)(4)(iv)	Documentation of use of only instrument air controllers	Pneumatics at PFs	Maintain records	8/23/11
60.5420(c)(5)(i)	For storage vessels with condensate throughput >1 bbl/d and crude oil >21 bbl/d, records required by 63.774(b)(2)-(8)	Storage vessels	Maintain records	8/23/11
60.5420(c)(5)(ii)	For storage vessels with condensate throughput <1 bbl/d and crude oil <21 bbl/d, documentation of throughput	Storage vessels	Maintain records	8/23/11
60.5421(a)	Comply with requirements of 60.486a	NG Processing plants	Maintain records	8/23/11
60.5421(a)(1)	When leak is detected, mark with visible identification until repaired	Pressure relief devices	Maintain records	8/23/11

Proposed Regulatory Provision	Requirement	Applies to:	Due Date:	Start Date:
60.5421(a)(2)(i)-(x)	Record leaks in log including instrument and operator id, date of leak and attempts to repair, repair methods, delay of repair information, signature of o/o who decided repair could not be made w/o process shutdown, expected date of repair, lift of id numbers for equipment designated for no detectable emissions	Pressure relief devices	Maintain records for 2 years	8/23/11
60.5422(a)	[Vva] 60.487a(a)-(c)(2)(i)-(iv), (vii) - LDAR requirements for valves, pumps and compressors	Equipment components	6 mos after startup; semi-annually thereafter	8/23/11
60.5422(b)	Number of pressure relief devices in gas/vapor service subject to quarterly monitoring requirements	Pressure relief devices	6 mos after startup; semi-annually thereafter	8/23/11
60.5422(c)	Number of pressure relief devices in gas/vapor service for which leaks were detected and number of devices for which leaks were not repaired	Pressure relief devices	6 mos after startup; semi-annually thereafter	8/23/11
60.5423(a)	Retain records of calculations and measurements of 60.8 performance test	Sweetening units	Retain records for 2 years	8/23/11
60.5423(b)	Excess emissions reports for any 24 hour period of excess sulfur emissions	Sweetening units	Semi-annually	8/23/11
60.5423(c)	Certify exemption analysis that facility's design capacity is <2 LT/D of H2S	Sweetening units	Retain records for life of facility	8/23/11
60.5423(d)	Alternative compliance demonstration for sulfur removal efficiency for facilities with a design capacity <150 LT/D of H2S	Sweetening units	Retain records for life of facility	8/23/11

8.2. Stated Goal Is Inconsistent with Proposed Rule Text and Requirements

EPA’s intent to simplify, streamline, and minimize the burden associated with notification, recordkeeping, and reporting has not been translated into rule text that accomplishes the stated goal and objectives. EPA has significantly underestimated the magnitude of the annual industry cost burden for notification, recordkeeping, reporting (initial and on-going annual), permitting, and management activities. For example the rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility.

Based on EPA's estimate of 20,000 completions/recompletions per year, this would result in 80,000 notifications being filed annually.

EPA states in the preamble that they desire to minimize duplication of notification through incorporating KKK and LLL requirements into OOOO.

“In addition, we are proposing to incorporate the requirements in 40 CFR 60, Subpart KKK and 40 CFR 60, Subpart LLL into the new subpart OOOO so that **all requirements applicable to the new and modified facilities would be in one subpart**. This would **simplify and streamline** compliance efforts on the part of the oil and natural gas industry and **could minimize duplication of notification**, recordkeeping and reporting. [emphasis added]” FR Vol. 76, 52746

EPA also provides additional support for their intention to reduce the burden associated with notification and reporting requirements:

“Given the number of these operations, we believe that **notification and reporting must be streamlined** to the extent possible to **minimize undue burden** on owners and operators, as well as **state, local and tribal agencies**.” [emphasis added]” FR Vol. 76, 52747

While we agree with this goal, the overwhelming administrative burden that would be imposed by the proposed rule falls far short of achieving this outcome.

8.3. Notifications

Affected facilities are so small that all notifications should be eliminated or limited to a single notice coincident with the first annual report. The requirements as proposed could literally lead to daily notifications, as activities change.

Newly added rule administrative costs for notifications and compliance management have *not* been included in cost-effectiveness analyses. These exclusions impose a low bias on compliance costs for *all* emission sources. If EPA elects to retain multiple notification requirements, these obligations need to be streamlined into a single year end summary notice and the cost benefit analyses need to be revised to more accurately reflect actual burdens.

Upset notification in HH and OOOO within 2 days and documentation of affirmative defense is unnecessary and burdensome. As proposed, these notifications would be required for the smallest of emission exceedances with no reportable quantity threshold being set. This is contradictory to other EPA reporting rules such as those under CERCLA and EPCRA where reportable quantities are established for unauthorized releases. Requirements for immediate reporting of unauthorized releases of VOCs should be left to the states as they are best equipped to handle any response that might be required as a result of the release. Immediate reporting to the EPA serves no purpose (see Section 10.2.1 for further details).

8.3.1. Well Completions - Multiple Notification Requirements for Well Completions

The rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility which include:

- Post-marked 30 days after construction [§60.7(a)(1)],
- Post-marked 15 days after initial startup [§60.7(a)(3)],
- Post-marked 60 days or as soon as practicable before the changed is commenced [§60.7(a)(4)], and
- 30 days of the commencement of the well completion operation [§60.5410(a)(1) or §60.5420(a)(2)].

Based on EPA's estimate of 20,000 completions/recompletions per year, this would result in 80,000 notifications being filed annually. The necessary additional staff to manage the notification requirements has not been included in the cost-benefit analysis.

API requests that all the §60.7(a) General Provisions notification requirements be eliminated since they are not appropriate for completions operations. The definitions of both "construction" and "initial start-up" do not apply to the flowback and cleanup portions of the well completions operations. Please see Section 15.7 for further discussion on the completions notifications.

8.4. Recordkeeping

Many of the recordkeeping requirements proposed are ambiguous and need further clarification. API requests the following clarifications to the recordkeeping requirements.

Suggested Rule Text:

§60.5420

- (c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section.
- (1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).
- (i) Records identifying by API well number and date flowback ended, each flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facility ~~well completion operation for each gas wellhead affected facility~~ conducted during the reporting period;
- (ii) Record of deviations and reasons for the deviations in cases where ~~well completion operations with flowback immediately following~~ hydraulic fracturing stimulation at natural gas wellhead facilities onshore were not performed in compliance with the requirements specified in §60.5375.
- (iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. ~~You must maintain the records specified in paragraphs (e)(1)(iii)(A) and (e)(1)(iii)(B) of this section. (A)~~ For each flowback immediately following hydraulic

fracturing stimulation at natural gas wellhead facilities onshore ~~gas wellheads affected facility~~ required to comply with the requirements of §60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion including but not limited to wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, and where combustion is not allowed due to fire hazard, conditions that may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. The duration must be specified in hours of time.

~~(B) For each gas wellhead affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.~~

* * * * *

- (4) For each continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~ affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(~~iv~~iii) of this section.
- (i) Records of the date, and location ~~and manufacturer specifications~~ for each gas-driven pneumatic controller installed.
 - (ii) Records of the determination that the use of high bleed gas-driven pneumatic controllers ~~devices~~ is predicated and the reasons why.
 - ~~(iii) If the pneumatic controller affected facility is not located at a natural gas processing plant, r~~Records of the manufacturer's specifications. For low bleed pneumatic controllers, specifications must verify guarantee that the device is designed such that weak stream ~~natural gas~~ emissions are less than 6 standard cubic feet per hour.
 - ~~(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used.~~
- (5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.
- (i) If required to reduce emissions by complying with ~~§63.766, §60.5395(b)~~, maintain the following records ~~specified in §63.774(b)(2) through (8) of this chapter~~.
 - (A) A copy of the operating plan if using §60.5415(e)(1).
 - (B) A copy of manufacturer certification if using §60.5415(e)(2)
 - (C) A record of the measured values of the parameters monitored.
 - (ii) Records of the determination of the throughput, pressure, and emissions using the methods in §60.5395(c) to demonstrate emissions are below 12 TPY. ~~that the annual average condensate throughput is less than 1 barrel per day per storage vessel and~~

~~crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under §60.5395(a)(1) and (a)(2).~~

8.5. Reporting

Proposed compliance assurance approaches, including electronic reporting, should be revised or excluded from the Final Rule.

8.5.1. Annual Report Timing

Annual NSPS Subpart OOOO reports at Title V Permitted facilities should be allowed to be combined and submitted with other Title V reports for the same facility. For non-Title V permitted facilities, the report should be submitted a year and 60 days after final publication of the rule in the federal register to allow for submittal of a single report for multiple facilities versus a year after the anniversary date of the initial startup date.

8.5.2. Exception Reporting

The rule as proposed requires that for every source category you must report all the records gathered. However, it is excessive and burdensome to both industry and the agencies to require reporting of all the records versus just deviations from the rule. Most of the NSPS regulations require only reporting of deviations such as in 40 CFR 60, Subpart J under §60.107(c) or 40 CFR 60, Subpart Kb under §60.115b. Requiring that all the records are reported will result in a great deal of work for industry to prepare the reports and for the agencies to review all the information supplied to find deviations. In order to reduce this unneeded burden on both industry and agencies, API recommends that only deviations be reported in the annual report.

Suggested Rule Text:

§60.5420

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due ~~1 year after the initial startup date for your affected facility or~~ 1 year and 60 days after the date of publication of the final rule in the Federal Register, ~~whichever is later, or with a Title V report the year after~~ publication of the final rule in the Federal Register. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

* * * * *

(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) ~~through and~~ (b)(2)(iii) of this section.

- (i) An identification by API well number and date flowback ended of each flowback immediately following hydraulic fracturing stimulation at natural gas wellhead facilities onshore ~~well completion operation, as defined in §60.5430, for each gas wellhead affected facility~~ conducted during the reporting period;
- (ii) A record of deviations and reasons for the deviations in cases where ~~well completion operations with~~ flowback immediately following hydraulic fracturing stimulation at gas natural wellhead facilities onshore were not performed in compliance with the requirements specified in §60.5375 for each gas well affected facility.
 - ~~(iii) Records specified in §60.5375(b) for each well completion operation that occurred during the reporting period.~~
- (3) For each centrifugal compressor affected facility installed during the reporting period, documentation ~~that if~~ the centrifugal compressor ~~is was not~~ equipped ~~with dry seals as specified in §60.5380(a).~~
- (4) For each reciprocating compressor affected facility, ~~the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.~~
 - ~~(i) The cumulative number of hours of operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.~~
 - ~~(ii) Documentation that if~~ the reciprocating compressor rod packing was due for replacement according to one of the frequencies described in §60.5385(a), but was not replaced as specified ~~before the cumulative number of hours of operation reached 24,000 hours.~~
- (5) For each continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~ affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(~~iv~~iii) of this section.
 - (i) The date, site name, location and quantity of high bleed gas-driven manufacturer specifications for each pneumatic controllers installed.
 - (ii) ~~If applicable, d~~Documentation that the use of high bleed gas-driven pneumatic controllers devices is predicated and the reasons why.
 - (iii) For all low-bleed gas driven controllers installed, a statement certifying that each controller was designed to meet the emissions threshold of less than 6 standard cubic feet per hour. ~~For pneumatic controllers not installed at a natural gas processing plant, the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.~~
 - ~~(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions.~~

- (6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.
- (i) If required to reduce emissions by complying with paragraph §60.5395(a)(1), ~~the records specified in §63.774(b)(2) through (b)(8) of this chapter.~~ the API number of the location of the tank and date of installation.
- (ii) If exempt from §60.5395 in accordance with §60.5395(a), the API number of the location of the exempt tank and date of installation. ~~Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in §60.5395(a)(1) or (a)(2).~~

8.5.3. Electronic Reporting.

8.5.3.1 Electronic or Administrator Reporting Requirements in §63.775(g)

API is opposed to mandatory electronic reporting and supports voluntarily reporting at the operator's discretion. 40 CFR Part 63 Subpart HH, §63.775(g) requires electronic submittal of performance test results to EPA's Central Data Exchange (CDX) after January 1, 2012. API believes electronic reporting should not be mandatory and should only be voluntary. The electronic reporting tool (ERT) is used to electronically create and submit stationary source sampling test plans to regulatory agencies and, after approval, to calculate and submit the test results as an electronic report to the regulatory agency. Paper notification, test plans, and reports may still be required to satisfy individual state requirements. API does not advocate duplicate effort and until state requirements for redundant reporting have been eliminated it is premature to consider mandatory electronic performance test reporting. The added burden for preparing and inputting data into the ERT is cumbersome and the cost has not been adequately addressed.

Additionally, rule language is also unnecessarily vague with respect to test methods that need to be reported to the Electronic Reporting Tool (ERT). Specifically, of the 18 test methods referenced in Subpart HH, only six (6) methods (Methods 1, 2, 3A, 4, 10, and 25A) are compatible with the ERT. API submits that the ERT is still in its infancy and requires additional time to develop the remaining test methods, data elements, and incorporation of alternative emission calculation methodologies that are currently not included in this system. API recommends that the rule language be modified to indicate the following:

- Electronic reporting is voluntary (i.e., not mandatory);
- Test Methods 1, 2, 3A, 4, 10, and 25A are the test methods that can be reported to the ERT voluntarily; and
- Test results are due 90 days after the completion of a test, beginning with tests performed three (3) years after the publication of the final rule.

Reporting under multiple rules for a variety of purposes are likely to result in conflicting data and add a burden on operators to provide detailed emission assumptions and methodologies that are not well suited to rigidly defined data entry fields in electronic database reporting formats. For example, reporting VOC, NMHC, THC, GHGs, and HAP emissions under different programs is likely to result in confusion and misinform the public based on overlapping compounds, test method differences, and emission factor based approaches. Redundant reporting under different rules is unnecessary, burdensome, and not cost effective. For example, many state agencies require an annual emission inventory.

Experience with some existing EPA reporting tools indicate that they do not enhance reporting efficiency and require an inordinate amount of time to enter data, verify data entries, and tailor available data to the prescribed fields. Further, the security measures for data entry involve additional burden through time-consuming responses to multiple security questions for each entry.

Furthermore, based on the timetable associated with the current comment/response cycle for this rule, we do not anticipate that the rule will be finalized by the end of this year. However, §63.775(g) requires electronic submittal of performance test results after January 1, 2012. Given this language, EPA is effectively requesting that the data be submitted prior to the effective date of this rule. API does not believe that this is logical, rational, and strongly advocates a measured review process and an adequate beta test period for any electronic reporting tool, either voluntary or mandated.

EPA should also consider confidential business information or proprietary data limitations as this reporting requirement is reviewed and the cost burden is reassessed. EPA should examine the likely business impact from the disclosure of required data elements before they are reported and potentially subject to public availability. Any electronic reporting would likely burden owners/operators.

8.5.3.2 Requested Comments on Electronic Reporting for NSPS Subpart OOOO (V.D.3.).

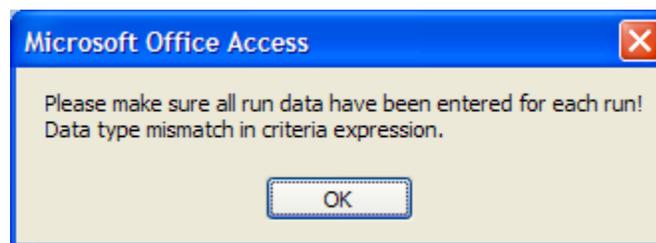
EPA has requested comment on electronic reporting. API believes electronic reporting should not be mandatory and supports only voluntary electronic reporting at the operator's. Electronic reporting is already required for many of these sources in the Mandatory Greenhouse Gas Reporting Rule (40 CFR, Part 98). Reporting conventions associated with VOC, NMHC, THC, and GHG emissions will result in conflicted data and add a burden on operators to provide detailed emission assumptions. Redundant reporting under different rules is unnecessary, burdensome, and not cost effective. If retained, the cost for duplicative reporting requirements should be addressed and justified. Any electronic reporting would burden owners/operators. Furthermore, experience with some existing EPA reporting tools indicate that they do not enhance reporting efficiency. Delays in the final version of the Electronic Greenhouse Gas Reporting Tool (e-GGRT) for the GHG MRR and the e-GGRT system for Subpart W show the difficulty in creating a

tool that is useful to both the EPA and industry. The experience with e-GGRT indicates that a more efficient system needs to be developed before requiring usage by industry. Another difficulty associated with electronic reporting is the reporting of new and/or alternative test methods that are slow to be incorporated into the system. Small companies could also be disproportionately burdened as they typically lack personnel specifically dedicated to environmental management issues.

8.5.4. EPA Should Not Require Use of the Electronic Reporting Tool (ERT)

While EPA continues to make improvements to the Electronic Report Tool (ERT), it still needs much more refinement before it is a useable tool by industry. Outlined below are some of the ongoing concerns with the ERT's ability to allow submittal of accurate, consistent and complete test data. EPA should resolve these issues before requiring its use in a regulatory program.

- a. The range of stack test methods which can be used in the ERT is narrow. Not only does the ERT lack the capability to accommodate all of EPA's test methods, there is only limited provision for use of other state, local or consensus standard methods. In the latest version (v4) EPA incorporated a "custom method" option; however, this is limited to methods which are analogous to EPA Method 5 (using extractive sampling and displacement gas volume meters) or instrumental methods like EPA 3A, 6C, 7E or 10. This feature allows one to enter a custom pollutant, but there is no provision to change the calculations or configure the data inputs to reflect different types of test instrumentation (e.g., for methods that use a rotameter or venturi and time to determine sample volume), different standard temperatures, blank corrections, etc.
- b. ERT has serious functional flaws that can cause calculation, printing and other errors. Error handling is very poor; error messages are not very helpful (e.g., see below), or the program may crash.



- c. Handling of detection limits is not integrated in a manner that would assure appropriate data calculations and data flagging in the test report. Entry of detection limits in comment fields and manual formatting of test data (e.g. [<3.2] for a result below detection limits at a detection limit of 3.2) almost assures that data will not be handled correctly or consistently.
- d. Analytical lab data can only be entered as a single net result for each sample fraction, rather than as individual values for each measured value. This requires testers or laboratories to make an intermediate calculation prior to data entry. For example, gravimetric results generally consist of two weights (tare and final) for each sample

fraction. Each weighing is the result of several replicate weights until the difference between two sequential weighings is less than a certain value (0.5 mg for Method 5). Method 5, for example, does not specify whether the first weight, the second weight or the average of the two weights should be reported, and different testers and labs use different conventions. Thus, there can be a total potential error of as much as 2 mg in the net weight of a Method 5 sample fraction, depending on convention. This can represent a large error compared to sample weights for many modern sources leading to inconsistent results and poor data comparability. As another example, many instances of incorrect intermediate calculations were found in the ICI Boiler and EGU ICRs. For example, many testers failed to correctly handle detection limits when summing values for the five analytical fractions comprising total mercury in EPA Method 29 measurements when some fractions were detected and some undetected. This introduces serious potential data quality issues for mercury measurements by this method. EPA states that one of the benefits of ERT is to improve consistency of results; however, this oversight allows one of the most significant sources of inconsistency to persist.

- e. Some state and local test methods use a different standard temperature than EPA's standard temperature of 20 C (68 F). Standard temperature is hard coded into ERT with no provision for the user to change it, neither in any of the current method templates nor in the custom method option. This limits the use of ERT for local reporting requirements, requiring the tester to prepare separate test reports for WebFIRE and for local use.
- f. Some state and local agencies have different protocols for handling undetected results (e.g., substitution of ½ detection limits or zero for undetected results). As noted above, ERT does not correctly flag undetected results in the test report nor allow for alternative detection limit protocols. Testers would need to prepare separate test reports for local use and WebFIRE use.
- g. There are numerous instances of ambiguous wording and nomenclature in ERT. For example, in Test Plan field 7b, a column is headed "Corrected analyte" and another is "Corrected %". If the intent is to list the diluent indicator (e.g., O₂ or CO₂) and diluent reference concentration, these should say so and the calculations should be handled accordingly.
- h. ERT does not allow for all common diluent corrections. O₂ diluent corrections embedded in ERT only work if the diluent is air. If a combustion source uses O₂ or nitrogen enrichment such that O₂ concentration in the diluent is not 20.9% by volume, the diluent-corrected test result would be incorrect.
- i. The laboratory(ies) performing sample analysis is not identified by name in the test report, unless the tester chooses to do so in a comment field. All organizations involved in the test program should be identified in the report.
- j. There doesn't appear to be a way to handle DGM (dry gas meter) volumes during non-sampling periods, e.g. leak checks.

- k. ERT can handle only three test runs. For some processes it is necessary to make more than three test runs to obtain representative emissions factors.
- l. The number format in the test report is not configurable so that values are reported with an appropriate number of significant digits. This generally gives a highly misleading impression of results precision. For example, the Emissions Summary page uses scientific notation with 3 significant figures (2 decimal places), while the Stack Data Results Summary and Stack Data Results Detail pages use decimal format. In one example, the mass of water gained in the impingers is reported to 11 significant figures (8 decimal places) and all average results are reported to three decimal places, ranging from 2 to 9 significant figures depending on the parameters. The appropriate number of significant figures will vary, depending on specific details of a given test and parameters.
- m. Some document control errors persist e.g. page count for one example test report was incorrect, resulting in last page numbered as "12 of 13".
- n. Data flags and comments entered on the lab data tab (e.g., ADL, BDL, DLL) are not carried forward to the results summary or detailed results report pages, presenting a misleading impression of high data quality.
- o. ERT does not include printing of all primary input data (e.g., point to point run data, lab data with flags and comments, impinger weights, etc.) among the report options. This is a key shortcoming for quality control review and auditing of test reports.
- p. Some formatting issues remain (e.g., in one example several pages of the printed test report had headers but no data).

8.6. Performance Test Methods and Compliance Monitoring Requirements

8.6.1. General

- a. The use of extensive cross referencing to a myriad of other rules and test methodologies renders the requirements in Subpart HH nearly impossible to follow, confusing to the extent that it unnecessarily adds to the compliance burden, and likely to lead to errors and misunderstanding.
- b. The test protocols, requirements, and methodologies specified in the rule are unnecessarily complex, likely not technically achievable in certain instances, and unnecessarily costly.
- c. The requirements for continuous monitoring of parameters to demonstrate continuous compliance are similarly unnecessarily complex, likely not technically achievable in certain instances, and unnecessarily costly.
- d. EPA should redraft the performance testing and continuous compliance monitoring requirements of the rule to:

- i. simplify requirements,
- ii. include only requirements appropriate for the large number and type of dispersed small sources which would be subject to the rule,
- iii. reduce the extensive cross referencing in the testing and monitoring requirements to reduce the confusing nature of the proposed rule and lessen the chance that the confusing construction of the rule will inadvertently lead to non-compliance incidents through misunderstanding, and
- iv. reduce the unnecessary economic burden.

8.6.2. Applicable to Subpart OOOO and Subpart HH/HHH

Requirements for using an enclosed combustion device for HAP or VOC control under NSPS Subpart OOOO or NESHAP Subpart HH or HHH are specified in §63.771.

- a. Paragraph 63.771(d)(1)(i) specifies that an enclosed combustion device must meet one of the following performance criteria:
 - (A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §63.772(e); or
 - (B) Reduces the concentration of either TOC or total HAP in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of §63.772(e); or
 - (C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §63.772(e), operates at a minimum temperature of 760 degrees C.
- b. Operational conditions in the oil and natural gas production sector are very different from those experienced at refineries or chemical plants. Conditions of intermittent, variable and turbulent flow and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API requests:
 - i. The requirement in §63.771(d)(1)(i)(A) should be modified to require reduction of either TOC or HAP emissions by 95% on a volumetric concentration basis using a “carbon balance” methodology for analysis of the exhaust stack effluent from an “enclosed combustion device” being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO₂ and O₂, and 10 for CO should be specified for testing of the stack effluent gas. The CO₂ measured

using Method 3A should be adjusted downward by the latest published atmospheric CO2 concentration, as reported from the Mauna Loa monitoring site by NOAA’s Earth System Research Laboratory, multiplied by the ratio of O2 measured in the stack effluent as compared to the ambient O2 content of 20.8 volume %. (3A measured CO2 (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O2 (ppmv)/208,000 (ppmv) ambient O2 concentration).

Destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(CO2_c +CO)/(CO2_c +CO+(3*TOC))$$

where:

CO2_c = CO2 ppmv concentration measured in the stack via method 3A minus the ambient CO2 ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following table shows this calculation and outcome for an assumed stack effluent composition:

Outlet CO2	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O2	150,000	
Ambient O2	208,000	
Ambient CO2	388	
Outlet CO2 _c from combustion	29,720	Outlet CO2 - ((Ambient CO2 X (Outlet O2/Ambient O2))
Destruction Efficiency	99.70%	(CO2 _c +CO)/(CO2 _c +CO+(3*TOC))

The suggested carbon balance methodology is similar to that described in EPA’s Technical Report “EPA-AA-SDSB-80-05” “Carbon Balance and Volumetric Measurements of Fuel Consumption” used by EPA for vehicle testing and is identical to that described in the UNFCCC CDM methodology found at:

http://cdm.unfccc.int/filestorage/C/6/X/C6XWJCBZSTR2S0SQKE7ZFQYEDIBNPZ/Procedure%20to%20determine%20the%20flare%20efficiency%20based%20on%20the%20flame%20temperature%20in%20an%20enclosed%20flare.pdf?t=bmh8bHYyeTJ0fDAPxze0_d4bXBK2OcnA8D9I and also described on page 630 of the “John Zink Combustion Handbook” available for purchase from Amazon books.

- ii. Modify the requirement in §63.771(d)(1)(i)(B) of the proposed rule to demonstrate that TOC (as propane – method 25A) concentration in the stack exhaust from an enclosed combustion device is less than 200 ppmv corrected to 3% CO₂ in the stack. Using the carbon balance methodology described above a 200 ppmv TOC would correspond to slightly above 98% destruction efficiency which leaves a wide margin between the alternative of 95% destruction efficiency.

As proposed, the rule indicates an alternative control device exhaust concentration requirement of less than 20 ppm corrected to 3 percent oxygen. Typically, combustors have carbon dioxide concentrations of approximately 3% and oxygen concentrations of approximately 16%. 20 ppm corrected to 3 percent oxygen corresponds to an in-stack actual concentration of approximately 5 ppm which would likely correspond to a destruction efficiency approaching 100% (the alternative requirement is 95% destruction). API believes this is a simple mistake and the correct formulation would be corrected to 3 percent CO₂. For the type, small size, and number of sources subject to these requirements API believes a more appropriate formulation would be correction to 3% CO₂. This would be consistent with §§63.772(h)(6)(vi) and 63.772(h)(7)(i)(B), where the proposed rule indicates the concentration limits for the manufacturers of combustors conducting a performance test and specifies an exhaust concentration requirement of being less than 10 ppm corrected to 3 percent carbon dioxide. This appears inconsistent with the 3% oxygen correction stated in §63.771(d)(1)(i)(B), where it outlines the general field performance test requirements. As stated, the manufacturers of combustors would actually have a less restrictive limit than owners conducting a field performance test.

- iii. Modify the requirements in §63.772(h) to conform with the carbon balance test methodologies described above for field performance testing. The ppmv performance criteria stated in §63.772(h)(7)(i)(B) should be modified to 100 ppmv TOC (as propane) corrected to 3% CO₂ which corresponds to ~99% destruction efficiency and provides ample buffer between a manufacturers tests for certification and the required 95% destruction efficiency for field demonstration. As currently constructed, the manufacturers certification testing must show ~ 99.97% destruction which is unreasonable and certainly not supportable from the standpoint of rule cost effectiveness.
- iv. Remove §63.772(h)(7)(i)(C) to eliminate the consideration of CO concentration in the manufacturers certification testing. By imposing a CO concentration, EPA is effectively converting the destruction efficiency testing to combustion efficiency testing which is not required by nor appropriate for the proposed rule.
- v. Eliminate the requirements for measurement of inlet flow to an enclosed combustion device and outlet flow from an enclosed combustion device, as per §63.772(e)(3)(i)(A), or outlet flow from an enclosed combustion device, as per §63.772(e)(3)(i)(A). As described above, these measurements are unnecessary to accurately determine destruction and removal efficiency (DRE) for the control device.

Additionally, requiring Method 2, 2A, 2C, or 2D to determine volumetric inlet flow is not appropriate and likely not technically feasible for accurate measurement. The waste gas inlet stream to an enclosed combustion device being used for control for either a storage tank or a small or large dehydrator will be a low pressure (essentially atmospheric) low flow stream with very low velocity which is almost impossible to measure accurately using any of the specified methods. Rather than attempting to measure such a stream EPA should specify the use of E&P TANK or a process simulation model such as ProSim or HySys to determine the inlet flow and composition of a waste gas stream routed to an enclosed combustion device from a storage tank and GlyCalc 3.0 or higher dehydrator model or a process simulation model such as ProSim or HySys to determine the inlet flow and composition of a waste gas stream routed to an enclosed combustion device from either a small or large dehydrator. The problems with attempting to measure such a stream are more completely described in Attachment H which is incorporated in these comments by reference.

The outlet flow from a typical enclosed combustion device has the same low pressure, low velocity, and difficulty for measurement issues as the waste gas inlet. If EPA insists on a mass balance approach rather than the much simpler and accurate carbon balance approach, API recommends the rule enable the use of Method 2B to calculate outlet flow for the combustion device using the model output information discussed above to calculate inlet flow and composition to the combustion device.

- vi. Eliminate the proposed rule revisions that change the temperature monitoring device accuracy requirements from +/- 2 to +/- 1 percent of the temperature being monitored expressed in degrees C. In the preamble, EPA states:

"we are proposing to revise the temperature monitoring device minimum accuracy criteria ... to better reflect the level of performance that is required of the temperature monitoring devices. We believe that temperature monitoring devices currently used to meet the requirements of the NESHAP can meet the proposed revised criteria without modification."

However, EPA provides no data or analysis to support the need for a more stringent accuracy requirement. At typical incinerator temperatures, any change, in combustion efficiency and emissions caused by a temperature change represented by the difference between 1 and 2 percent accuracy is most likely not detectable. Further, EPA contradicts the need for the rule revision by stating that it believes that current temperature monitoring devices can meet the criteria without modification. If current devices are sufficiently accurate, why is there a need for a new accuracy standard? Absent data and analysis that demonstrate that the new accuracy requirements would provide better emissions control, there is no need to revise the existing accuracy criteria. The primary rule revision effect would be to unnecessarily burden operators to modify internal procedures and recalibrate select devices. Simply because a certain standard of accuracy can be attained is not sufficient to demonstrate that it should be required.

vii. Clarify that the requirements in §63.771(d)(1)(i) for enclosed combustion control devices for "sources except small glycol dehydration units" (i.e., large dehydration units and tanks) is correctly interpreted as:

- Operators may comply with the requirements to reduce HAP emissions in accordance with §§63.771(d)(1)(i) (A), (B), (C), or (D).
- Operators that comply with the requirement to reduce HAP emissions in accordance with §63.771(d)(1)(i)(C) are only required to conduct an initial performance test that demonstrates that the combustion zone profile has a minimum temperature of 760°C. "Uniform" should be deleted from §63.771(d)(1)(i)(C) because uniform is not defined in the rule and the complex interactions of flame zone reactions, mixing, and convective and radiative heat transfer preclude "uniform" combustion zone temperature profiles. Rather, it appears that EPA's intent is that the combustion zone profile must have a minimum temperature of 760°C such that there are no low temperature pathways for HAPs to escape destruction. API recommends the following rule revision:

§63.771

(d)(1)(i)(C) For a control device that can demonstrate a ~~uniform minimum~~ combustion zone temperature of 760°C during the performance test conducted under §63.772(e), ~~operates at a minimum temperature of 760 degrees C.~~

- In addition, the rule appears confused because the requirements for demonstrating "a uniform combustion zone temperature" are not specified in the performance testing section, nor otherwise discussed in the rule. Therefore, API recommends that the following initial performance testing requirements to determine a combustion zone profile be added as §63.772(e)(3)(vii):

§63.772

(e)(3)(vii) To determine compliance with the minimum combustion zone temperature of 760°C specified in §63.771(d)(1)(i)(C), the owner or operator shall profile the combustion zone temperature as follows:

(A) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the measurement sites in the combustion zone.

(B) The gas temperature at each measurement site shall be determined using a temperature monitoring device having a minimum accuracy of ±2 percent of the calibrated range expressed in °C, or ±2.5 °C, whichever is greater.

- Operators that comply with the requirements to reduce HAP emissions in accordance with §63.771(d)(1)(i)(D) are not required to conduct a performance test because this compliance option is an operating standard and does not have a numerical component.

8.6.3. Applicable to Subpart OOOO – Tanks controlled with an enclosed combustion device

- a. Specifying Subpart HH/HHH hazardous air pollutant requirements for testing and performance demonstration of VOC control from tanks is completely inappropriate, unnecessary, and yields unnecessary complexity, confusion, and burden.
- b. API requests that EPA include a separate performance demonstration and monitoring section which is specific to and appropriate for Subpart OOOO rather than simply referring to the requirements in Subpart HH/HHH. This separate performance demonstration and monitoring section should adapt the methodologies described above appropriately for VOC control using enclosed combustion devices. See Section 16.8 for suggested rule text to specify storage tank requirements within Subpart OOOO.

8.6.4. Applicable to Subpart HH/HHH – Dehydrators controlled with an enclosed combustion device

- a. §63.771(f)(1)(i) provides requirements for enclosed combustion control devices for small glycol dehydration units, and lacks compliance options parallel to §63.771(d)(1)(i) (C) and (D).
- b. API requests that compliance options parallel to options §63.771(d)(1)(i) (C) and (D) and appropriate for small dehydrators be added to §63.771(f)(1)(i).
- c. In §63.772(e)(3)(iii)(B)(4) the proposed rule refers to using GRI-GLYCalc 3.0 or higher for determining the mass emission rate of TOC and HAP at the inlet to a control device. It is confusing because it refers to GRI-GLYCalc 3.0 or higher but then later in the same paragraph it refers to EPA Methods 18 and 25A, which of course are testing methods.
- d. API requests that §63.772(e)(3)(iii)(B)(4) be modified to clearly allow use of GRI-GlyCalc to determine the mass emission rate of TOC and HAP at the inlet to a control device.

8.6.5. Other Comments

- a. It is not apparent that ASTM D6420–99 (2004) can be used for HAP measurements. The rule should clarify that ASTM D6420–99 (2004) - in addition to Method 18 in 40 CFR part 60, appendix A and any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A – are applicable for measuring benzene, BTEX, or total HAP emissions from any affected source.
- b. §63.772(f)(3) states: “For inlet gas flow rate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under §63.772(h). However, §63.772(h) only applies to manufacturer performance tested combustion control devices and would not apply to dehydrators that are not equipped with manufacturer performance tested combustion control devices.

- c. §63.772(i)(1) requires the continuous monitoring of the inlet flow rate for manufacturer performance tested combustion control devices. The flowmeter is required to have an accuracy of +/- 2%.

As previously discussed, flowmeters for this type of low pressure low velocity stream application and service are not feasible and demonstration of flow to the enclosed combustion device should rely on appropriate models (E&P TANK or process simulation model for tanks, GlyCalc or process simulation model for dehydrators) to set volumetric operating parameters for conforming with a manufacturers range for a combustion device. For example, a process simulation model may be used to establish a lower and upper limit for oil throughput in a storage tank which corresponds with a manufacturers Btu operating range for a combustion device. An operator could then use their average production rates, as determined by normal production volume accounting methods and frequencies, to ensure they are within this range and demonstrate compliance.

API requests that EPA modify the proposed rule to eliminate continuous flow metering to control devices and enable the use of appropriate models to set limits on normally measured parameters to demonstrate compliance. Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce burden while providing for compliance demonstration and monitoring.

- d. §63.772(i)(2) requires that a pilot flame be present at all times of combustion control device operation. This requirement is not applicable for combustion control devices equipped with electronic ignition systems. For combustion control devices equipped with electronic ignition systems, the rule should add a requirement that these be operational at all times of combustion control device operation.

API recommends the following revision to the rule language:

§63.772

- (i)(2) For combustion control devices equipped with pilot flames, a pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with §63.773(d)(3)(i)(H)(2). For combustion control devices equipped with electronic ignition systems, the electronic ignition systems shall be operational at all times of combustion control device operation.

API recommends the following revision to the rule language:

§63.773

- (d)(3)(i)(H) For a control device model whose model is tested under §63.772(h),²

~~(1) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.~~

~~(2) A~~ heat sensing or UV sensing (fire-eye) monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

- e. §63.772(i)(3) requires monthly visible emissions tests using Method 22 of 40 CFR 60, Appendix A. Monthly testing is excessively burdensome and not needed to assure combustor compliance because continuous monitoring of combustion control ignition is already required and the materials being combusted are inherently combustible.

API recommends that the rule be revised to require testing every six months with an allowance for less frequent testing for units that routinely pass the visible emissions test. For example, for a unit that passes two consecutive emission tests, the next test would be required in 12 months. If EPA insists on retaining the onerous monthly testing requirement, then similar relaxed testing requirements for a compliant unit should be added. For example, for a unit that passes two consecutive monthly tests, the next test would be required in 2 months, and so forth until an annual testing schedule is achieved.

- f. §63.772(i)(4)(iii) requires the replacement of fuel nozzle(s) and burner tubes after one failed visible emissions test. EPA should *not* stipulate specific equipment replacement or maintenance practices that may be unnecessary and wasteful, or possibly not address the problem. The rule should delete these requirements and state that operators must perform maintenance and/or replace equipment as needed to restore combustion control device functionality.
- g. §63.773(b) requires semi-annual inspections of manufacturer performance tested combustion control devices. EPA should *not* stipulate a specific inspection frequency; rather inspection and maintenance practices should be based on manufacturer specifications and requirements as documented in the required inspection and monitoring plan.
- h. §63.773(d)(1)(iii) requires that the owner or operator conduct CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months. EPA should *not* stipulate a specific frequency for CPMS checks and audits. Rather, the appropriate frequency should depend on the monitoring parameters and equipment. API recommends that the frequency of CPMS checks and audits will be documented in the site-specific monitoring plan, and supported by manufacturer recommendations.
- i. §63.773(d)(3)(i)(A) in the redline version of the proposed rule states:

“For a thermal vapor incinerator that demonstrates during the performance test conducted under §63.772(e) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in °C, or ± 2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative in the combustion chamber downstream of the combustion zone temperature.”

This rule passage is poorly written and confusing. It infers that a thermal vapor incinerator performance test that does not demonstrate that combustion zone temperature is an accurate indicator of performance is not required to install a temperature monitoring device. Further, demonstration that “combustion zone temperature is an accurate indicator of performance” would require testing over a range of temperatures and correlating performance with temperature. This is not a performance testing requirement in the proposed rule nor should it be. In addition, the proposed rule does not define or discuss how to determine “a location representative of the combustion zone temperature.” To address these issues, API recommends the following revisions to the Federal Register version of §63.773(d)(3)(i)(A):

§63.773

(d)(3)(i)(A) For a thermal vapor incinerator ~~that demonstrates during the performance test conducted under §63.772(e) that the combustion zone temperature is an accurate indicator of performance~~, a temperature monitoring device equipped with a continuous recorder shall be installed at a location in the combustion chamber downstream of the combustion zone. The monitoring device shall have a minimum accuracy of ~~±12~~ percent of the calibrated range temperature being monitored in degrees C, or ±2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location ~~representative of the combustion zone temperature~~ or downstream temperature measurement during the performance test.

The phrase “or downstream temperature” has been added to the recommended rule text because of the practical considerations associated with measuring combustion zone temperatures. The high temperatures and reactive chemical species rapidly degrade in-situ measurement devices. Equipment properly installed for downstream temperature measurements typically have a much longer operational life and provide an accurate indication of combustion conditions. As long as the compliance temperature is in the same location as the temperature measured during the performance test, that location provides compliance assurance.

- j. §63.773(d)(3)(i)(C) should clarify that a heat sensing monitoring device to indicate continuous ignition of the pilot flame is not required for flares equipped with electronic ignition systems.
- k. For boilers and heaters where the waste gas is not mixed with or used as the primary fuel, to address the temperature sensor location issue previously discussed for thermal vapor incinerators, API recommends the following revisions to the Federal Register version of §63.773(d)(3)(i)(D):

§63.773

(d)(3)(i)(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder shall be installed. The temperature monitoring device shall have a minimum accuracy of ~~±12~~ percent of the

calibrated range ~~temperature being monitored~~ in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature or downstream temperature measurement during the performance test.

- l. The current rule flow meter accuracy requirement of $\pm 10\%$ for regenerative-type carbon adsorption systems should be retained in §63.773(d)(3)(i)(F)(1). EPA has not demonstrated the need for a revised flow meter accuracy requirement including how this revision will improve emission control, nor demonstrated that the additional cost to replace existing equipment and install more accurate flowmeters is justified.
- m. The checks of mechanical connections for leakage required by §63.773(d)(3)(i)(F)(1) should be performed every three months, rather than monthly, in concert with the required visual inspections. Absent moving parts, mechanical connections are extremely slow to develop leaks and more frequent checks add unnecessary labor and recordkeeping burden.

8.6.6. Complete Rewrite Required

API is not attempting to provide a full “mark-up” of the current proposed rule language due to the confusing complexity and extensive cross-referenced manner of its current construction. However, we would certainly be willing to draft, or work with EPA to draft, replacement testing and monitoring requirements and rule text. The replacement requirements must be appropriate for the large number of dispersed small sources subject to the rule with the rule text constructed in a straight forward and non-confusing manner with minimization of the use of cross-references. It is likely that cooperating on this issue will yield better results in a quicker time period.

8.7. Use of NESHAP Emission, Monitoring and Performance Testing Standards in NSPS

The proposed Subpart OOOO would impose a 95% control requirement on affected storage vessels. But, it would do so by incorporating by reference the Subpart HH MACT storage vessel control requirements. *See* 76 Fed. Reg. at 52800 (proposed §60.5395(a)). The preamble and TSD purport that the 95% control requirement is the product of an objective BDT analysis. *See, e.g., id.* at 52763-4; TSD at Section 7. And, EPA proposes that the consistency between the MACT and NSPS storage vessel requirements provides a coincidental opportunity for regulatory streamlining. *See* 76 Fed. Reg. at 52764 (“Because the controls used to achieve the 95-percent HAP reduction are the same as the proposed BSER for VOC reduction for storage vessels (*i.e.*, VRU and flare),” EPA proposes “that storage vessels subject to the requirements of subpart HH are exempt from the proposed NSPS for storage vessel in 40 CFR part 60, subpart OOOO.”).

But, on closer inspection, the storage vessel BDT determination was hard-wired to achieve the same level of control as Subpart HH – undermining the BDT determination and effectively (and unlawfully) extending Subpart HH major source MACT requirements to area source storage tanks. For example, in the BDT analysis, EPA explains that, “We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent.” *Id.* at 52763; *see also* TSD at 7-12. EPA does not explain in the preamble or the TSD why other control efficiencies were

not examined or assessed – it simply begins the BDT analysis with the conclusion that 95-percent control is appropriate.

Having selected its preferred control techniques and control efficiencies, EPA is then forced to back-calculate vessel throughput levels that produce costs satisfying the statutory BDT cost criterion. 76 Fed. Reg. at 52763-4. Yet, this analysis precludes other potentially relevant regulatory alternatives – such as marginally less effective controls that might be applied to a broader range of storage vessels. The Agency's failure to consider other control techniques and other levels of control efficiency that might be achieved by its preferred techniques is arbitrary and capricious.

Even if the same control standard of 95% reduction is selected and economically justified, the more stringent monitoring and performance testing requirements required by the CAA in section 112 for HAPs are not required in section 111 for criteria pollutants. This is discussed in more detail in Sections 16.6 and 16.13 of these comments.

8.8. Third Party Verification

EPA asks for comment on the possibility of requiring affected facilities to provide “third party verification to assure compliance” with well completion requirements. 76 Fed. Reg. at 52750. According to EPA, assuring compliance with these requirements could be “very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers” because “emission sources in the oil and natural gas sector, especially well completions, are widely geographically dispersed (often in very remote locations.” *Id.* A third party verification system could be used to “leverage compliance assurance efforts of the EPA and state, local and tribal agencies” by relieving them “of the burden of receiving thousands of paper or e-mail well completion notifications each year, yet still provide them quick access to the information.” *Id.* EPA also posits that such a system could benefit affected sources, for example by reducing the advance notice for well completions to “much less than 30-days” and eliminating the need for a 2-day follow up notification. *Id.*

There are several problems with this proposal. First, it is not clear what role third party verifiers would play. In part of the discussion of this issue, EPA suggests that the role would be limited to developing and maintaining a “clearinghouse” of information. EPA clearly envisions that such a “clearinghouse” would assist regulators (and the public) by providing easy access to well completion notifications. But, by establishing a clearinghouse, it does not seem that third-party verifiers would do more than the ministerial function of accepting notifications and putting them in an accessible database.

Alternatively, EPA describes the role of third party verifiers as substantive – *i.e.*, “verification of the data collection, compilation and calculations.” In addition, EPA suggests that the scope of third party verification might be extended to required electronic reporting using the ERT. The third party verifiers might assume the task of “review[ing] and verify[ing] that the information submitted to the EPA is truthful, accurate and complete.” *Id.* However, no further details about the scope and authority of the third party verifiers' substantive role is provided. For example, what happens if a third party verifier determines that a calculation error occurred. Would the verifier make the needed correction, or return the notification to the affected facility for correction and resubmission, or

perhaps report a potential violation to EPA? The proposal does not say. Similarly, would third party verifiers make field inspections to verify the information submitted in notifications and/or assess well completions determined not to be subject to Subpart OOOO? Again, the proposal does not say.

This lack of clarity is compounded by the fact that no proposed rule text is provided. As a result, commenters do not have adequate notice of how the third party verification system would work and cannot ascertain whether the regulatory text would faithfully implement the concept. To resolve these problems, EPA must repropose the third party verification requirement before finalizing it.

More fundamentally, EPA has not explained where it finds legal authority to impose a third party verification requirement. To be sure, EPA has broad authority to require such monitoring, recordkeeping, notification, and reporting requirements as are reasonably needed to assure compliance with Part 60 emissions standards. However, there is nothing on the face of the statute (and the statute cannot reasonably be construed as) authorizing EPA to require affected facilities to hire contractors to do EPA's work. EPA freely admits in the proposal that assuring compliance with the well completion requirements would be "very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers." The clear purpose of the third party verification requirement would be for the third party verifiers to relieve this burden. Simply put, EPA does not have authority under the CAA to require affected facilities to hire contractors to do work on behalf of the Agency.

Moreover, such a requirement would run afoul of the Anti-Deficiency Act. A third party verification requirement clearly would circumvent the limited Congressional budget appropriation for EPA enforcement activity. Such circumvention violates the prohibition against authorizing expenditures "exceeding an amount available in an appropriation or fund for the expenditure." 31 U.S.C. § 1341(a)(1)(A).

For these reasons, even with a reproposal, EPA is without authority to impose a third party verification requirement.

8.9. Equipment Specific Notification, Recordkeeping and Reporting Requirements

8.9.1. Storage Vessels Monitoring

Installation and operation of a CPMS on each storage vessel control system is required under §60.5410(e)(4). The CPMS must be installed and operated in accordance with §63.773(d) requirements, which include hourly data collection/measurement and recording. At remote, unmanned locations, the required data collection would be difficult due to the lack of electrical power that would be needed for a continuous data system. Installing electrical generation equipment would be prohibitively expensive given the small size of these emission sources. Therefore, API recommends that the final rule allow manual data collection on a schedule that matches an owner's site visit schedule.

8.9.2. Sweetening Unit Recordkeeping and Reporting

Under §60.5365(g)(3) "Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to

comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §60.5405 through §60.5407 and paragraphs §60.5410(g) and §60.5415(g) of this subpart.”

Although these units are exempt from the standards and monitoring requirements, they remain subject to unnecessary recordkeeping and reporting requirements. API recommends a change to §60.5365(g)(3) as follows: “Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §§60.5405 through §60.5407 and paragraphs §60.5410(g) and §60.5415(g) **and paragraphs §60.5423(a), (b), (d) or (e)** of this subpart.”

9. COMBUSTION DEVICE REQUIREMENTS

9.1. Flares - “Flame Present At All Times”

EPA has deferred to the general design requirement for flares in §60.18 and §63.11 if a flare is to be used as a control device. Since oil and gas operations are not always steady state, flares with continuously lit pilots (24/7) can sometimes unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emissions stream being burned. An example would be a flare installation used as a backup control device when a VRU is used. And in some cases, fuel gas has to be purchased where there is insufficient gas available from the production stream to fuel a flare pilot. EPA can resolve this issue in two ways.

9.1.1. Clarify What is Meant By “Flame Present At All Times”

Please clarify what is meant by “flame present at all times” by adding new regulatory text in §60.5415(i) and §63.769(c)(8) stating that “flame present at all times” in §60.18 and §63.11 refers to a pilot that must only be lit at all times while a VOC or waste stream is being sent to the flare for emissions destruction.

9.1.2. Allow Use of Electronic Flare Ignition Devices

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 303. Presumably this was published because EPA approves of the design and recognizes its benefits and wanted to promote its use in industry. EPA should not lose the benefits of this control technology enhancement by disallowing its use in this rule. With this being an established and preferred technology in Natural Gas STAR, operators should not have to petition EPA for approval under its new control technology provision. See Sections 15.3.8 and 16.11.

9.2. “Completion Combustion Devices” Are Not Considered Flares

Section 60.5375(a)(3) provides that “You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”

EPA appears to have chosen the term “completion combustion device” so that the pit flares, which the preamble states at p. 52758 are not a “traditional flare control device” would not be subject to §60.18. The preamble indicates that this is the case “because of the multiphase slug flow and intermittent nature of the discharge of gas, water and sand over the pit.” As a result, pit flares cannot comply with the technical requirements of this section.

However, Subpart OOOO also includes a definition of flare at §60.5430 which reads as “*Flare* means a thermal oxidation system using an open (without enclosure) flame.” This definition would include pit flares because they use an open flame to oxidize the gas portion of the flowback. Likewise, while pit flares are typically used and may not have been intended to be defined as flares, some operators may choose to use traditional flare devices or be required to do so by state or local rules. These would more clearly be subject to §60.18.

Suggested Rule Text:

§60.5430

Flare means a thermal oxidation system using an open (without enclosure) flame. [Completion combustion devices are not considered flares.](#)

9.3. Proper Cite for NSPS Flare Requirements is §60.18(b)

Subpart OOOO cites the requirements in the Part 60 General Provisions for flares, but the cite given is overly broad. The proper cite is §60.18(b), but the rule more generally cites §60.18.

Suggested Rule Text:

§60.5401

* * * * *

(f) Flares used to comply with this subpart must comply with the requirements of §60.18(b), [except as provided in §60.5415\(i\)\(1\) and \(2\).](#)

§ 60.5415

* * * * *

[\(i\) Flares used for compliance with this section must comply with §60.18\(b\), except as provided in §60.5415\(i\)\(1\) and \(2\).](#)

[\(1\) A “flame present at all times” as required in §60.18\(c\)\(2\) means that a pilot must be present at all times while a VOC or waste stream is being sent to the flare for emissions destruction, or](#)

[\(2\) thru the use of an electronic ignition device.](#)

9.4. Equipment Routing Vapors From Affected Facilities To Process Are Not Considered Control Devices

EPA has recognized that many of the emission reductions provided for in this rule may be able to be routed back into the process and sold as natural gas or petroleum products. In Subpart HH, at §63.761, EPA defines a “closed-vent system” such that “If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system.” EPA also included a definition of “routed to a process or route to a process” in the proposed rule text of §60.5430. API requests that EPA add a new provision in §60.5415 to exclude equipment that route the vapors back to the process and meet the definition provided in §60.5430 from being considered as control device or closed vent system for the purposes of this subpart.

Suggested Rule Text:

§60.5415

(j) For the purposes of this subpart if the vapors from the affected facility are routed back to process and meet the definition provided for *routed to process* in §60.5430 then this equipment is not considered a control device or closed vent system.

10. STARTUP, SHUTDOWN, AND MALFUNCTION PROVISIONS

Given that the SSM exemption in Part 63 Subpart A has been vacated by the courts, API supports EPA's edits to Table 2 of NESHAP Subpart HH that render SSM references in the General Provisions not applicable. API also supports EPA's proposal to address malfunctions as distinct from routine operating conditions, but we object to the manner in which EPA proposes to do so. API believes EPA is not authorized to subject malfunction events to an emissions standard for which EPA did not consider the emissions or costs of control associated with malfunctions. API endorses the comments submitted separately from the SSM Coalition on this issue (See Attachment D), particularly with respect to establishing an alternative emissions limitation for malfunctions. We address flaws in EPA's legal analysis below, followed by specific recommendations for a work practice as an alternative emissions limitation for malfunctions. In the comments on a work practice as a standard for malfunctions, Subpart HH references are given first, with Subpart OOOO references in brackets.

10.1. EPA's Legal and Technical Analyses of SSM Events are Fundamentally Flawed

10.1.1. Flawed Analysis of NESHAP SSM

EPA observes in the preamble that the startup, shutdown, and malfunction (“SSM”) provisions contained in the Part 63 General Provisions were vacated by the D.C. Circuit in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) (“*Sierra Club*”). 76 Fed. Reg. at 52787. The Agency then explains that “[w]e are proposing the elimination of the SSM exemption in the two oil and gas NESHAP” and that “[c]onsistent with *Sierra Club v. EPA*, the EPA is proposing to apply the standards in these NESHAP at all times.”

With regard to periods of startup and shutdown, EPA asserts that “operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard.” *Id.* Consequently, “we have not proposed different standards for these periods.” *Id.* As to malfunctions, “EPA has determined that malfunctions should not be viewed as a

distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times.” *Id.* However, EPA does propose to establish “an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions in both of the MACT standards,” which would be available if affected sources can prove by a preponderance of the evidence that qualifying criteria have been met. *Id.* at 52788.

The proposal to eliminate the SSM provisions in the two existing rules is not based on an accurate reading of *Sierra Club*, is not supported by any rational explanation as to why the elimination of the SSM provisions is justified, and is arbitrary and capricious given that EPA fails to provide any analysis of why affected sources reasonably can be expected to meet the emissions limitations and standards that the Agency proposes to apply during periods of SSM.

To begin, EPA's proposal “that the standards in these rules apply at all times” is not, as EPA claims, “[c]onsistent with *Sierra Club v. EPA*.” The decision in that case was grounded in the court's assertion that § 112 requires emissions standards to apply at all times. *Sierra Club* at 1027 (“Congress has required that there must be continuous section 112-compliant standards.”). Based on this, the court held the SSM General Provisions do not comport with § 112 because, in the eyes of the court, the SSM provisions are not “section 112-compliant” emissions standards. *Id.* at 1028 (“Because the general duty is the only standard that applies during SSM events — and accordingly no section 112 standard governs these events — the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously.”). Notably, the court did not hold that EPA is prohibited from setting separate standards for periods of SSM. It simply held that standards for such periods must be developed according to the § 112(d) MACT process.

Thus, the proposal to eliminate the SSM provisions from the two source categories (Subparts HH and HHH) subject to this proposal is not “consistent” with *Sierra Club* because there is nothing in that case that supports the conclusion that vacatur of the Part 63 General Provisions necessarily requires “the established standards in these rules [to] apply at all times.” EPA's flawed legal analysis provides no support for the proposal to eliminate the SSM provisions in the two rules.

This fundamental legal flaw is magnified by the Agency's failure to provide any explanation whatsoever as to why it is appropriate to now apply the existing emissions standards to periods of SSM. For example, EPA made no effort to obtain emissions information from the two source categories for periods of SSM and provides no other evidence or analysis supporting its assertion that it is appropriate to apply the existing standards to periods of SSM. Moreover, EPA fails to investigate the record data developed during the promulgation of the existing standards to assess whether those data are characteristic and representative of emissions during periods of SSM. In short, the Agency simply asserts with no record basis that the existing standards should apply to periods of SSM. This unsupported assertion provides no basis for extending the existing standards to periods of SSM – the failure to seek relevant data, assess existing data, and investigate whether the existing standards should appropriately apply to periods of SSM is facially arbitrary and capricious and provide wholly

inadequate support for the Agency's proposal.

With regard to malfunctions, EPA's proposal to provide an affirmative defense for periods of malfunction is without merit. Comments recently submitted by the "SSM Coalition" on EPA's proposed standards for Sewage Sludge Incinerators explain in detail that: (1) EPA must take malfunctions into account when setting § 112 emissions standards; (2) the proposed affirmative defense is not a permissible substitute for setting emissions standards for periods of malfunction; and (3) the proposed affirmative defense is unreasonable and impracticable. *See* Letter to EPA Docket Center (EPA/DC) from the American Chemistry Council, *et al.*, Comments on Proposed Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Docket ID No. EPA-HQ-OAR-2009-0559, at 6-20 (Nov. 29, 2010). We incorporate these comments by reference.

A further flaw in EPA's reasoning is that it has failed to account for the costs of a standard that does not accommodate malfunctions. To assure continuous compliance, affected facilities have only two choices – install redundant processing and pollution control equipment so that operations can continue during a malfunction, or shut down the affected facility until the malfunction can be rectified. In either case, affected facilities would incur substantial costs directly attributable to the standard that have not been accounted for in the formulation of the rule.

For these reasons, EPA should set aside the proposed affirmative defense for periods of malfunction and, instead, set a work practice standard for such periods.

10.1.2. Flawed analysis of NSPS SSM

Consistent with its proposed approach to the oil and gas NESHAPs, "EPA is proposing standards in [the Part 60] rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction." 76 Fed. Reg. at 52766. EPA claims that it "has taken into account startup and shutdown periods" in the proposed Part 60 standards. *Id.* And, EPA proposes "to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions." *Id.* To qualify for the affirmative defense, an affected source "must prove by a preponderance of the evidence that it has met" specified criteria. *Id.*

With regard to applying the proposed standards to periods of startup and shutdown, EPA has failed to provide record evidence as to how it has "taken into account startup and shutdown periods" in the proposed rules. Thus, EPA's assertion that the standards accommodate emissions during periods of startup and shutdown is unsupported and fundamentally arbitrary. EPA further undermines its position by asserting that "any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim." *Id.* In essence, EPA is trying to remake the law by asserting that its unsupported conclusions will be adopted *unless* commenters prove these unsupported conclusions to be wrong. This cannot be. EPA unambiguously has the obligation to support its proposed standards with substantial evidence

and must include in the proposed rule “the factual data on which the proposed rule is based.” CAA § 307(d)(3)(A). EPA has failed on both counts with regard to its unsupported assertion that the proposed standards should apply to periods of startup and shutdown.

EPA's proposal to provide an affirmative defense for malfunctions is equally flawed. EPA begins its analysis by asserting that it “has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards.” 76 Fed. Reg. at 72766. In support of this assertion, EPA first cites *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1058 (D.C. Cir. 1978) for the proposition that “nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards.” 76 Fed. Reg. at 52766.

Yet, *Weyerhaeuser* is inapposite – it is a Clean Water Act case that has no bearing on EPA's authorities and responsibilities under CAA § 111. More directly relevant cases – those decided under § 111 itself – tell a very different story. As explained in the SSM Coalition's comments (Attachment D), the courts have long recognized that a “technology based standard discards its fundamental premise when it ignores the limits inherent in technology.” *NRDC v. EPA*, 859 F.2d 156, 208 (D.C. Cir. 1988). For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that “‘start-up’ and ‘upset’ conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated.” *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are “necessary to preserve the reasonableness of the standards as a whole.” *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held CAA technology-based standards must be capable of being met “under most adverse circumstances which can reasonably be expected to recur,” such as during periods of SSM. 627 F.2d at 431 n.46. Thus, the relevant case law makes clear that EPA is authorized and obligated to account for periods of malfunction when setting Part 60 standards.

Nevertheless, EPA presses on by arguing that “it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards” because “[t]he “application of the best system of emission reduction” is more appropriately understood to include operating units in such a way as to avoid malfunctions.” 76 Fed. Reg. at 52766. This rationale makes no sense because EPA effectively is defining BDT as an affected facility that does not malfunction. EPA has asserted no record basis for such a determination and could not if it tried because malfunctions are inevitable, notwithstanding best efforts. In any event, as explained above, EPA has failed to estimate and take account of the added costs associated with a rule that requires compliance during malfunctions (*i.e.*, the costs of installing redundant equipment or the business interruption costs of shutting down).

EPA lastly asserts that “even if malfunctions were considered a distinct operating mode, we

believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for affected facilities” because “it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category.” *Id.* Four decades of operating under the existing Part 60 malfunction provision belie this claim. A work practice requiring best efforts to minimize emissions during malfunction events consistent with the application of good air pollution control practices is a tried and true way to “account for the myriad different types of malfunctions that can occur.” EPA’s failure to explain why such an approach cannot continue to be successfully applied represents a critical flaw in its conclusion that standards cannot and should not be developed for malfunction events.

10.2. Notifications and Reports for Malfunctions

Proposed paragraph §63.762(d)(2) [§60.5415(h)(2)] would require a notification of a malfunction to be submitted within 2 business days after the initial occurrence of the malfunction in order to preserve an affirmative defense. This paragraph would additionally require a report within 45 days after the malfunction. These deadlines are arbitrary, unrealistic, and unwarranted.

10.2.1. The Proposed 2-Day Notification is Unrealistic and Unnecessary

The provisions of §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] would specify a 9-step procedure for determining whether a given malfunction event qualifies for the affirmative defense. In most cases, it would not be realistic to complete this determination process within 2 days following the occurrence of the event. Facilities might therefore tend to routinely submit the 2-day notification in order to preserve the potential for an affirmative defense, even in cases which subsequently are determined to not qualify. Furthermore, there is no environmental benefit that would accrue from this notification, and similar provisions in refinery consent decrees do not require it. The result of this unrealistic and unnecessary requirement, then, would be to burden both the facility and the regulatory agency having jurisdiction with the processing of paperwork that has no associated environmental benefit. As proposed, these notifications would be required for the smallest of emission exceedances with no reportable quantity threshold being set. This is contradictory to other EPA reporting rules such as those under CERCLA and EPCRA where reportable quantities are established for unauthorized releases. Requirements for immediate reporting of excess emissions of VOCs should be left to the states as they are best equipped to handle any response that might be required as a result of the release. Immediate reporting to the EPA serves no beneficial purpose. However, if EPA insists on a notification requirement, the rules should allow at least 15 business days following the occurrence of the event for this notification to be submitted.

10.2.2. Malfunction Reports Should Be Submitted with the Semi-Annual Reports

The rule already requires, at §63.775(e) [§60.5423(b)], the submission of excess emissions reports on a semi-annual basis, and EPA has established the semi-annual basis as being appropriate for all compliance-related reporting through numerous rulemakings. In fact, EPA promulgated the Recordkeeping and Reporting Burden Reduction Rule for the

expressed purpose of simplifying and unifying reporting schedules. EPA stated this intent in the preamble to that rule:

“The Agency now believes that the semiannual reporting frequencies contained in recently promulgated NSPS and NESHAP regulations and proposed in this rulemaking for all types of information are generally appropriate. . . EPA sees no reason to retain different reporting frequencies in the NSPS and NESHAP General Provisions compared to the reporting frequencies contained in recently promulgated rules.”^C

As noted by EPA, there is no reason to require a reporting frequency that differs from the semi-annual basis adopted by the agency. It would be contrary to the agency's own assessment of an appropriate reporting frequency to arbitrarily require malfunction reports to be submitted within 30 days.

10.3. EPA Has No Mandate To Impose SSM Requirements in NSPS Rules.

EPA states that “In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods” (see 76FR52766). However, API has found nothing in the Docket to support such a statement for the NSPS Subpart OOOO standards. In particular, the Technical Support Document (EPA-OAQR-0505-0045) does not have any statement about startup, shutdown emissions. The only reference to malfunctions is in a discussion about workovers being performed to address malfunctions of downhole pumps and this type of equipment mechanical malfunction has no emissions to atmosphere. EPA has predominately added work practices (i.e. compressor seal change and RECs). Although an SSM event could potentially cause the owner/operator to exceed the requirements of a work practice, it is unclear how the exceedance of a work practice would be tied to an “emission exceedance”. It is also not clear how an SSM event would cause “emission exceedance” in the case of a design standard such as the proposed requirements for pneumatic controllers. Finally, even though the sulfur recovery standard is an emission standard, it is simply a strengthening of the standard promulgated in the mid-1980s. No consideration of SSM events was found in the Technical Support Document as discussed above.

EPA has no mandate by the Court to cover periods of SSM in NSPS emission standards. In fact, EPA would have an obligation to show that covering such SSM periods within the NSPS emission standard was cost effective. Simply stating that SSM events have been considered is insufficient. By definition, SSM events have emissions in excess to the standard. API has not found any instance where EPA has defined what the SSM events are, the emission associated with the event, the control required obtain the emission standard and the cost effectiveness of requiring that control. The Clean Air Act (CAA) does not contain any provision allowing EPA to ignore cost effectiveness when setting NSPS and SSM events are no different. For these reasons, API recommend that EPA remove all references to SSM provisions from NSPS Subpart OOOO. If EPA continues to impose the emission standards at all times (including during SSM events), EPA must identify the SSM events, the controls required to maintain the emission standard and justify the cost impact of including the emission standard during the SSM event.

^C 61 Federal Register 47840-47852, September 11, 1996; page 47844, first two columns.

10.4. §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] Should Constitute a Work Practice for Compliance

For the reasons set forth in the comments above on the legal analysis, the steps specified in §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] should be specified as a work practice for compliance in the event of a malfunction, rather than being specified as a basis for an affirmative defense. In the preamble to the proposed rulemaking, EPA presents numerous reasons for not accounting for malfunctions in the setting of emission standards for routine operating conditions, yet proposes to apply these emission standards to malfunction events. This is logically inconsistent and statutorily inappropriate. If the standards are to apply to malfunction events, then the emissions and costs of control associated with malfunction events should have been included in the evaluation of the standards. As explained by EPA, however, not only was this not done – it would not be feasible to do so.

On the one hand, then, EPA is obligated to set standards that are “achievable” under section 112(d)(2) of the Clean Air Act. On the other hand, it is not feasible to develop an emission standard that governs malfunction periods. This scenario is expressly addressed in section 112(h) of the Clean Air Act, which allows EPA to set work practice standards for situations where “it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . .” Malfunctions fit within the situations described in the definition of “not feasible to prescribe or enforce an emission standard” as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Consequently, EPA should set work practice requirements to address periods of malfunction. The steps set forth in §63.762(d)(1)(i)-(ix) [§60.5415(h)(1)(i)-(ix)] would constitute an appropriate work practice standard for malfunctions, in which case the notifications specified in §63.762(d)(2) [§60.5415(h)(2)] should be replaced by a semi-annual reporting requirement.

10.5. Address Weather and System Outage Issues

Excess emissions can result from weather conditions or gathering system/processing plant outages that are beyond the control of the operator. Many well sites are remotely located and most are unmanned facilities. Inspection and maintenance visits occur on average anywhere from weekly to twice per month, depending on the location and time of year. In some areas, winter weather makes it difficult to visit sites causing extended periods between site visits. Although telemetry is often utilized for new production well sites to optimize the need for operator attention, weather conditions can affect not only the control device (flare flameout) but can also affect telemetry which would catch and report such discrepancies. System outages to the gathering system, gas treating plants, or gas processing plants occur infrequently but can occur several times during the year. These outages immediately result in a stop in production. Wells that are equipped to automatically shut down, do so. However, most wells must be visited manually in order to shut in the well and associated equipment. Once the system is restored and open to production flow, operators must begin the process of visiting the wells to open them back to production and restore associated operating equipment and control devices. EPA should specify how they would consider weather and “system” outages that are beyond the control of the upstream operator in a malfunction work practice.

10.6. Provide an Allowance for Reasonable Periods of Maintenance

EPA should provide an allowance for a reasonable period of routine maintenance for the control device. Proper operation of a control device includes periodic routine maintenance, and manufacturers of control devices typically recommend preventive maintenance on a semi-annual basis. EPA has stipulated in other rulemakings^D that standards do not apply during planned routine maintenance, other than a work practice standard that such periods shall not exceed 240 hours per year and records must be maintained to document such periods.

11. REVISING THE MACT FLOOR

Once EPA establishes a MACT standard for a particular source category, the Agency has the authority under § 112(d)(6) to “review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years.” In other words, EPA does not have unfettered discretion to revisit a prior MACT determination once that determination has been issued. Rather, EPA may revise a prior determination only “as necessary” according to explicit statutory criteria. *Cf. New Jersey v. EPA*, 517 F.3d 574, 582 (D.C. Cir. 2008) (Thus, EPA can point to no persuasive evidence suggesting that [the statute’s] plain text is ambiguous. It is therefore bound by [the statute] because “for [] EPA to avoid a literal interpretation at *Chevron* step one, it must show either that, as a matter of historical fact, Congress did not mean what it appears to have said, or that, as a matter of logic and statutory structure, it almost surely could not have meant it,” *Engine Mfrs. Ass’n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996), showings EPA has failed to make.”).

In the proposal, EPA explains that, “Pursuant to CAA sections 112(d)(2) and (3), we are proposing MACT standards for subcategories of glycol dehydrators for which standards were not previously developed.” 76 Fed. Reg. at 52746. Similarly, EPA states that, “We are also proposing MACT standards for storage vessels that are currently not regulated under the Oil and Natural Gas Production NESHAP.” *Id.* These statements make it clear that EPA is not invoking § 112(d)(6) as the authority for the new proposed standards – indeed, the preamble provides no analysis of “developments in practices, processes, and control technologies” to justify the proposed standards, as would be required if EPA were relying on § 112(d)(6). And, there is no mention of § 112(d)(6) in relation to the proposed new standards. EPA unambiguously drives home this point – “For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we are proposing no revision to the existing NESHAP pursuant to section 112(d)(6) of the CAA.” 76 Fed. Reg. at 52747. Instead, the Agency is invoking §§ 112(d)(2) and (3) directly, as if MACT standards for these source categories do not already exist.

EPA does not have such authority. As explained above, once EPA makes a MACT determination for a particular category, § 112(d)(6) provides the only authority for the Agency to later review and possibly revise the determination. Section 112(d)(6) expressly authorizes EPA to review existing determinations and provides specific criteria to guide and constrain the review. The existence of this express authority forecloses the Agency’s ability to directly invoke §§ 112(d)(2) and (3) for a given source category when a MACT determination has already been issued for the source category.

Notably, even if the Agency had invoked § 112(d)(6) as authority for revising the existing MACT standards, it still would not have authority to regulate the emissions points for which standards were not established in the first round of MACT rulemaking. Prior MACT determinations may be revised only “as necessary (taking into account developments in practices, processes, and control technologies).” Perceived “gaps” in the

^D Examples of regulatory provisions for maintenance of the control device include §60.102a(f)(3) and §63.119(e)(3) & (4).

original MACT determinations are not “practices, processes, and control technologies” that are properly within the scope of a § 112(d)(6) review.

In any event, it is not a reasonable exercise of authority to establish new emissions limitations under existing MACT standards when there is no significant risk associated with emissions from sources in the given source category. As explained in Section 20 of these comments, the available data overwhelmingly show that the current standards protect public health with an ample margin of safety. Establishing new standards under these circumstances is patently unreasonable and cannot be justified under § 112(d)(6) because the so-called regulatory “gaps” in the current rules clearly are not contributing to unacceptable risk. This is regulation for the sake of regulation and, as such, contradicts Congress’s clear intent that an ample margin of safety is an appropriate stopping point for emissions limitations under § 112.

12. CHANGE IN THE PROTOCOL FOR DETERMINING RESIDUAL RISK FOR NESHAP

As noted in the Federal Register (FR) announcement, EPA is required under section 112(f) of the Clean Air Act (CAA) to evaluate the risk to public health that remains after implementation of the technology-based national emission standards for hazardous air pollutants (MACT standards). EPA proposes, in this rulemaking, to change the manner in which this “residual risk” is evaluated. API has several concerns with respect to these proposed changes. Please see Attachment E which contains the Residual Risk Coalition letter commenting on this issue.

12.1. Lack of Statutory Authority for the Changes

As EPA notes, the process that the agency has followed for residual risk evaluations was established in accordance with a protocol mandated by the CAA, including preparation and submission to Congress of the methods to be employed. These methods include the two-step process described in the FR announcement. The first step in this process is to determine whether the maximum individual lifetime cancer risk (MIR) exceeds a presumptive limit of approximately 1-in-10 thousand. When the MIR is determined to be below this limit, the residual risk is deemed to be acceptable and the analysis moves to the second step. The second step, for situations in which the MIR is above 1-in-1 million, is to determine whether the standard provides an “ample margin of safety” to protect human health. EPA has established certain metrics for the determination of ample margin of safety through both the agency’s report to Congress and an extensive history of subsequent rulemaking.

API believes that EPA lacks statutory authority to make significant and substantive changes unilaterally to this procedure that has been established in accordance with CAA mandates, vetted with Congress, and ratified by precedent. There has been no indication from Congress or experience which indicates that the established procedure for evaluating residual risk has failed to be protective of human health. API objects to arbitrary changes which are unnecessary and unauthorized, and which needlessly add further uncertainty and complexity to a process that is already unduly burdensome.

12.2. Inappropriateness of the Changes

The new measures which EPA proposes to apply to the determination of acceptable risk and ample margin of safety are inappropriate. These new measures include:

- “total facility” consideration; consideration of risk from the total facility (facility-wide risk), rather than from only the portion of the facility subject to the rule,
- “demographic” consideration; consideration of risk across selected social, demographic, and economic groups within the population living near the facility, and
- “allowable emissions” consideration; consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard (versus the actual emissions from the facility).

Each of these considerations is discussed below and in Attachment E.

12.2.1. The “Total Facility” Approach to Conducting Risk Assessment Exceeds EPA’s Authority Under §112(f)

EPA explains in the proposal that, “To put the source category risks in context, we also examined the risks from the entire ‘facility,’ where the facility includes all HAP-emitting operations within a contiguous area and under common control.” 76 Fed. Reg. 52774. Because the CAA requires residual risk determinations to be conducted on a category by category basis, EPA does not have authority to consider the combined emissions from entire facilities when making a § 112(f) risk assessment for a given source category.

Section 112(f)(2)(A) unambiguously requires EPA, within 8 years after adopting a MACT standard for a given source category or subcategory, to “promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health.” Section 112(f)(2)(A) further dictates that, “Emissions standards promulgated under this subsection shall provide an ample margin of safety to protect public health.” It is not reasonable to construe these provisions as authorizing EPA to consider emissions from entire facilities in conducting risk assessments and potentially revising the underlying rule for the simple reason that the Congress clearly envisioned that full implementation of the MACT program would take longer than 8 years. Consequently, it would be impossible for EPA to fulfill its unambiguous obligation for § 112(f) standards to protect public health with an ample margin of safety in cases where facilities contain sources in a category where the 8 year deadline for conducting the § 112(f) risk review precedes the adoption of MACT standards for other sources at the facilities.

This is not mere hypothetical conjecture. The standards under review in this proposal provide a case in point. Certain of the facilities containing sources affected by one of the standards under review in this proposal also contain industrial boilers that will be subject to the MACT standard for industrial boilers. As a result, EPA currently is without authority to conduct a § 112(f) risk assessment for co-located industrial boilers because those boilers are not yet subject to a MACT standard due to the stay of the final rule. Thus, it is impossible for EPA to assure an ample margin of safety from total facility emissions for sources affected by the standards covered by this proposal. This demonstrates why the statute cannot be interpreted to allow consideration of emissions from entire facilities when conducting a § 112(f) risk review.

In addition, § 112(f)(2)(A) further provides that, “If standards promulgated pursuant to subsection (d) of this section and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to *emissions from a source in the category or subcategory* to less than one in one million, the Administrator shall promulgate standards under this subsection for such source category” (emphasis added). This provision unambiguously requires the § 112(f) risk assessment to be focused exclusively on “emissions from a source in the category or subcategory.” For this reason alone, EPA does not have authority to consider emissions from any sources other than those in the source category or subcategory under review at that time.

12.2.2. Demographics May Not be Considered in Conducting Risk Assessments Under §112(f).

EPA explains that, “To examine the potential for any environmental justice (EJ) issues that might be associated with each source category, we performed a demographic analysis of population risk.” 76 Fed. Reg. at 52774. Although EPA conducted an “environmental justice” assessment for the two rules covered by this proposal, EPA determined that those analyses do not provide a basis for imposing additional control measures in order to assure an ample margin of safety.

Because the term “public health” cannot reasonably be interpreted to include consideration of environmental justice in the § 112(f) context, EPA’s proposal to consider demographic analyses in conducting risk reviews under § 112(f) is not a proper exercise of Agency authority. Section 112(f)(2)(A) expressly instructs EPA to impose additional emissions controls if needed to provide an ample margin of safety “to protect public health.” The term “public health” is not defined in § 112 or in EPA’s Part 63 regulations.

In the context of EPA’s national ambient air quality program (“NAAQS”), the Supreme Court has observed that the “primary definition of the term” should be applied – *i.e.*, public health means “the health of the public.” *Whitman v. American Trucking Associations, Inc.*, 531 U.S. 457, 465 (2001). This conclusion emphasizes that the scope of the term “public health” should be dictated by the meaning of the word “public.” In relevant part, Websters Free Dictionary defines the adjective “public” to mean “of, relating to, or affecting all of the people or the whole area of a nation or state” and “of or relating to people in general.” These definitions emphasize that the word “public” should be construed expansively as describing the people as a whole, and not particular demographic segments.

EPA’s established approach to assessing potential impacts on public health under the NAAQS program is consistent with this meaning. EPA reasonably interprets the term “public health” to include consideration not only of potential impacts to the population as a whole, but also to sensitive subpopulations – recognizing that the objective is to protect the group rather than any particular individual in the group. *See, e.g.*, 71 Fed. Reg., 61144, 61145 fn. 2 (Oct. 17, 2006). But, sensitive subpopulations are identified according to their particular health-based sensitivities (*e.g.*, asthmatics) rather than demographic classifications

unrelated to particular health-based sensitivities (e.g., population without a high school diploma).

With this backdrop, it is not reasonable to construe the term “public health” as used in § 112(f) as allowing consideration of demographic classifications that bear no relationship to the potential health effects presented by the HAPs at issue for the given source category or subcategory. EPA’s proposal would unreasonably inject racial, ethnic, and other policy considerations into a program designed to provide protection for the public at large. For example, EPA suggests that the population without a high school diploma should receive extra scrutiny, yet does not afford the same scrutiny to other reasonably definable educational groups, such as those with a high school diploma, those with college degrees, and those with advanced degrees. There is simply no principled way to identify and define those groups that should receive extra scrutiny from those that do not. In short, EPA’s approach would inappropriately cause arbitrary policy and political considerations to trump objective scientific analysis. This is patently unreasonable and, as such, is not a supportable interpretation of § 112(f).

12.2.3. EPA Fails to Provide a Rational Basis for Using Allowable Emissions in Conducting Risk Assessments Under §112(f).

EPA uses the term “MACT allowable” emissions in the preamble to mean “the highest emission level that could be emitted by the facility without violating the MACT standards.” 76 Fed. Reg. at 52770. The Agency asserts that considering MACT allowable emissions in determining residual risk under § 112(f) “is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards.” *Id.* Without further explanation as to why it might be appropriate to determine and apply MACT allowable emissions in § 112(f) risk assessments, the Agency goes on to explain that it developed a ratio method of estimating MACT allowable emissions and applied these ratios in the risk assessment. Based on this analysis, EPA proposes to find that the “risks are unacceptable” under the current Subpart HH “due to MACT-allowable emissions” and, therefore, EPA proposes “to eliminate the 0.9 Mg/yr compliance alternative for dehydrators.” *Id.* at 52780.

EPA cannot lawfully use MACT allowable emissions in the proposed risk assessments and residual risk determinations because the Agency has failed to provide any reasoned explanation for why risk assessments based on actual emissions estimates are inadequate. It is noteworthy that § 112(f)(1)(A) required EPA to report to Congress on “methods of calculating the risk to public health *remaining, or likely to remain*, from sources subject to regulation under this section after the application of standards under subsection (d) of this section” (emphasis added). Section 112(f)(1)(B) required EPA also to report on “the *actual health effects* with respect to persons living in the vicinity of” affected sources” (emphasis added). These requirements clearly signal that Congress expected EPA to focus on actual risk and not hypothetical risk in implementing the requirements of § 112(f). Thus, it is not reasonable in the first instance for EPA to construe § 112(f) as authorizing the Agency to conduct risk assessments based on hypothetical “MACT allowable” emissions.

Moreover, the Agency's risk assessment methodology already is rife with conservative assumptions. For example, health benchmarks, such as acute reference doses, typically incorporate two to three orders of magnitude of conservatism to account for uncertainties, such as the extrapolation of animal toxicity testing data to humans. Similarly, the dispersion models used to predict off-site ambient HAP concentrations attributable to emissions from affected sources incorporate numerous conservative assumptions to simplify the analysis of highly complex factors, such as meteorology and atmospheric chemistry. In addition, risk assessments assume exposure to the most exposed individual on a continuous basis for an entire lifetime.

In light of the conservatism that already is inherent to EPA's risk assessment methodology, it makes no sense to apply yet another layer of conservatism – this time based on the hypothetical assumption that affected sources should be expected to emit more than the actual data indicate – to § 112(f) risk assessments. EPA has provided no data or analyses indicating that its current methodology results in negative bias. EPA has provided no data demonstrating that affected sources actually do emit at levels significantly higher than the actual data show for any significant period of time. In short, EPA's proposal to use hypothetical emissions levels in § 112(f) risk assessments is justified on nothing more than the bald assertion that sources *might* emit at these higher levels. The failure to provide a reasoned explanation as to why this approach is justified and the failure to provide any record evidence supporting the use of MACT allowable emissions render this proposal insupportable under the law.

13. AFFECT OF PROPOSED REGULATIONS ON STATES

13.1. Direct Regulatory Burden to State Environmental Regulatory Agencies.

The proposed rule will add tens of thousands of affected facilities annually. These affected facilities will result in a flood of notifications for new affected facilities that will each result in the submittal of annual reports, primarily into the State air pollution control agency. For this reason, API believes that consultation with the “appropriate representatives of the Governors and of State air pollution control agencies” of oil and natural gas producing states, as required by 42 USC 7411(f), is particularly important. The experience of these agencies is necessary to insure that only the notification and report information that is most beneficial to the agency is required to be submitted. API believes that the notification and recordkeeping requirements included in the proposed rule will flood the agencies with paperwork and effectively hide the useful information. API has made recommendation for the reduction of compliance assurance documentation below. However, EPA needs to recognize that these burdens are not only shouldered by industry, but the regulatory agencies as well.

13.2. Minor New Source Review (NSR) Permitting Programs

As discussed in Section 2, the proposed rule regulates affected facilities (i.e., individual pneumatic controllers and compressors, as well as RECs) that have not typically been regulated in an NSPS or NESHAP regulation in the past. Many states have developed minor source NSR permitting programs that go far beyond the requirements of the PSD (Prevention of Significant Deterioration) NSR or Title V Operating permitting programs. These programs typically have annual mass

emission thresholds similar to those included in the recent Tribal Lands FIP for Minor Sources (76 FR 38747, July 1, 2011; see Table 1, 76 FR 38792-3 for thresholds). However, some states also have an overriding requirement to permit facilities that contain NSPS or NESHAP affected facilities. This could result in a constant stream of permit revisions for very minor equipment activity (i.e., routine change out of equipment that occurs frequently). This unintended consequence of the proposed rule will bring a great burden to states that have this type of requirements and the O&G industry that operates within them for no environmental benefit. The NSPS/NESHAP programs are self implementing, thus do not require a permit to codify their requirements to make them enforceable. We recognize that EPA has already stated that the proposed regulation will not trigger Title V permitting requirements but we recommend that EPA expand this to include a recommendation in the preamble that "NSPS/NESHAP applicability alone should not trigger minor source NSR permitting requirements". We realize that such a statement will not bind the States, but it will be helpful in addressing this issue with the States

14. OFF-SHORE FACILITIES

API has found no evidence in the docket that EPA has considered the impact of the proposed rules on the offshore facilities that are under the EPA's jurisdiction for air quality issues. Offshore operations have unique and significant issues that directly impact the cost of compliance such as space on the platform for emission control equipment, weight allowance for additional equipment on the platform, remoteness of the platform, etc. Because of the unique circumstances around drilling and producing from offshore platforms and exploration vessels, complying with requirements designed for onshore activities is much more difficult and the costs are significantly higher when applying those same requirements to offshore facilities. For example, performing reduced emission completions on a new well completed on an existing offshore platform would most likely require a special separate installation to accommodate the additional REC equipment. The space on an offshore rig or platform is limited and designed to hold the equipment normally associated with drilling or necessary to manage the fluids expected during production. In addition, any recovered gas not meeting sales quality and capable of being flared, would be controlled using an existing flare typically designed as an emergency or safety control device. The flares used offshore are not designed to meet the §60.18 requirements. In Alaska, the vessels used for exploration are often foreign owned and operated and many times not designed to meet EPA stationary source standards. If the NSPS apply to offshore activities, drilling and subsequent production in Alaska will be significantly delayed until exploration rigs meeting the NSPS can be secured and moved to Alaska. With specific consideration of these issues for each of the standards EPA has proposed, API believes that the cost benefit requirement of the NSPS has not been satisfied. It is inappropriate for EPA to apply these standards to offshore facilities because of omission. API request that EPA specifically exempt offshore operations from the new standards it has proposed, as it has previously done in Subparts LLL and KKK.

TECHNICAL COMMENTS

15. WELL COMPLETIONS – NSPS SUBPART OOOO

API and its member companies are fully supportive of EPA's goals of minimizing VOC emissions from flowback immediately following hydraulic fracturing stimulation and have been among the earliest companies to adopt reduced such measures. Reduced emissions completions make sense in many scenarios, though not all. However, API does not support the manner in which EPA is proposing to regulate reduced emissions completions as discussed below in Section 15.1. Also, if EPA chooses to proceed in regulating reduced emissions completions, several issues must be addressed, as discussed in the rest of Section 15.

15.1. Legality of Regulation

Emissions from flow back immediately following hydraulic fracturing stimulation during well completions are fundamentally different than emissions regulated under any existing NSPS. It goes without saying that the purpose of gas wells is to produce natural gas. A well completion is not part of the normal operation of a well, in that completion activities do not continuously occur as a well is producing or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be "recompleted," this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

To date, EPA has not sought to impose § 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA has actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until "within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility." 40 C.F.R. §60.8(a). Similarly, performance test must be conducted under conditions reflecting "representative performance of the affected facility." *Id.* at §60.8(c). Periods of source construction and maintenance have never been determined to be "representative" of normal source operation under the NSPS program.

With this as a backdrop, EPA's proposal to set standards for well completions and recompletions is unfounded. To begin, as discussed more fully in Section 2 of these comments, production wells are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and gas production industry (such as natural gas processing plants) that EPA seeks to regulate in the proposed rule. EPA has not previously found and has not proposed to find that emissions from flowback immediately following hydraulic fracturing stimulation cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate flow back immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore under § 111.

In addition, EPA has not explained why it has reversed a decades-long practice under § 111 of regulating only emissions from normal operation of affected facilities and expressly excluding construction-related emissions from regulation. The proposal to regulate construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of § 111. The failure to explain why this departure is justified and the failure to present the legal basis for regulating non-routine emissions is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C). EPA should remove the requirements for reduced emissions completions from the proposed regulation. If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, EPA should repropose the requirements and include sufficient justification for their departure from not regulating construction-related emissions and present the legal basis for regulating non-routine emissions, under § 111, as discussed in Section 2. Furthermore, there are several issues that EPA needs to address which are discussed in the remainder of Section 15.

15.2. EPA Should Not Prescribe the Equipment Required for Reduced Emissions Completions

If EPA chooses to proceed in regulating flowback immediately following hydraulic fracturing stimulation, API is concerned with the prescriptive nature of the rule proposal for gas wellhead affected facilities. Section 60.5375(a) establishes three separate and prescriptive work practices, each of which must be followed in order to comply with the rule:

- Minimization of venting and routing recovered gases to the gas gathering line
- Use of specified equipment to maximize resource recovery^E and minimize releases to the environment
- Direction of flowback emissions that cannot be sent to a gathering line to a completion combustion device

Section 111 of the Clean Air Act establishes a strong presumption against prescribing control technologies:

CAA section 111(b)(5) "Except as otherwise authorized under subsection (h), nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."

Section 111(h) allows work practice standards where "it is not feasible to prescribe or enforce a standard of performance," API concurs that it is not feasible to prescribe a standard of performance for gas wellhead.

However, an underlying presumption of section 111 is that a standard of performance should allow the affected facility flexibility to meet a standard, rather than be required to use specific controls. Likewise, the NSPS rules are directed at criteria pollutants, which for the gas wellhead affected

^E The maximization of resource recovery is not a proper subject of regulation in a New Source Performance Standard under the Clean Air Act. Such considerations are appropriate only under RCRA.

facilities are VOCs. For this reason, we propose that the rule text be greatly simplified to provide objectives for the control of VOCs, rather than specify methods. This proposed rule text also reflects the complexity of completions and the variability of conditions that can be encountered in natural reservoirs. If EPA chooses to regulate flowback immediately following hydraulic fracturing stimulation, API proposes that EPA adopt a management system approach to well completions rather than trying to specify methods that may work well in one well or region, but be wholly unsuited in another. EPA has used this approach in many rules, such as Part 68, but has also used this approach in NSPS Ja for flares.

15.2.1. The Rule Should Not Specify Use of Specific Equipment

Paragraph 60.5375(a)(2) states that “You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations”. Any one of these pieces of equipment may not be necessary for any given flowback and cleanout operation, or not necessary for the entire time, so it is not appropriate to mandate it. Industry should be allowed to determine what equipment is required to safely minimize emissions.

15.2.2. The Rule Needs To Be Expanded To Allow For Use of Other Emission Reduction Techniques

Currently the proposed rule presumes a very simplistic understanding of completions - that all wells are simply flowed back using the reservoir energy to pits or flowback tanks. As structured, the rule precludes the use of other completion techniques which may be necessary to clean out a well and which may have equally low emissions in comparison to reduced emission completions. For instance reverse circulation completions have been utilized in a number of areas/wells with good success and low emissions. Reverse circulation completions have been presented in several Natural Gas STAR workshops and should not be ignored or precluded by the rule as proposed. In the future, new completion techniques and options may be developed which adequately clean-up the reservoir while providing for reduced emissions when compared to an uncontrolled “normal” flow-back. The rule, as proposed, would stifle this innovation and effectively preclude progress in better reservoir clean-up and reduced emissions.

15.2.3. The Rule Should Not Require Routing Liquids to a Storage Vessel

Sometimes flowback contains sands and other injection fluids that can damage storage vessels and make the condensate not salable; therefore, some of the flowback may get sent to a pit versus a storage vessel. The ability to flowback to a pit should be allowed.

15.2.4. The Rule Should Recognize Commercial Viability

The rule should recognize that installation of a collection line, to enable gas sales and REC's, prior to drilling or completing a well is only justifiable from an economic and surface disturbance/habitat disturbance perspective when the probability of a commercially successful well is almost assured. This is typical only for well developed areas with very well-known reservoir extent and productivity where the new wells are “in-fill” between existing wells. Although EPA attempted to deal with this uncertainty by excluding

exploration and delineation wells from the REC requirements the exclusion is not broad enough. API requests that EPA broaden this exclusion to include any well which the owner determines does not have a very high probability of success. The operator would be required to document their evaluation of wells probability of commercial success.

Suggested Rule Text: In order to address these concerns and others in later sections of these comments, API proposes two options. The preferred option would be to require the development and implementation of a management plan of how you will minimize VOC emissions associated with flowback immediately following hydraulic fracturing stimulation at gas wellhead facilities onshore instead of requiring specific equipment. The alternative option that API is proposing to replace requiring specific equipment would be to “*Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. When the well head pressure (in absolute units) immediately following perforation is four times the static sales meter pressure then the operator is obligated to flow the well to an available sales line or document the reasons for failing to flow to sales.*” This would specify when it would even be feasible when gas can be routed to the sales line which is discussed further in Section 15.3.2.

Preferred Option:

§60.5375

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

- (a) Except as provided in paragraph (f) of this section, for flowback immediately following ~~with~~ hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) ~~through and~~ (a)(32) of this section.
- (1) You must minimize the VOC emissions associated ~~with venting of hydrocarbon fluids and gas over the duration of~~ with flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, utilizing one or more of the following options routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system:
- (i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator.
- (ii) Capture and route VOC emissions associated with flowback immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore that cannot be directed to the gathering line to a completion combustion device except when conditions may result in a fire hazard, conditions may result in an explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion

devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to §60.18.

(iii) Other method that minimizes VOC emissions associated with flowback immediately following hydraulic fracture stimulation.

~~(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.~~ Develop and implement a management plan for each basin for how you will minimize VOC emissions associated with flowback immediately following hydraulic fracturing stimulation at a natural gas wellhead facilities onshore utilizing the options in §60.5375(a)(1). The plan must include:

(i) Methods and techniques to enhance direction of gas during the flowback immediately following hydraulic fracturing to the natural gas gathering system.

(ii) Equipment to be used.

(iii) Operating procedures

(iv) Definition of roles and responsibilities for implementation of the plan.

(v) Review of the effectiveness of the plan in minimizing VOC emissions every 2 years.

~~(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.~~

(b) You must maintain a log records for each well completion operation at each gas wellhead affected facility. ~~The log must be completed~~ on a daily basis and must contain the information records specified in §60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by §60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by §60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

- (f) For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(3)(1)(ii) of this section. ~~You must also maintain records specified in §60.5420(e)(1)(iii) for wildcat or delineation wells.~~
- (g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing at a natural gas wellhead facility onshore that ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f)

Alternative Option:

§60.5375

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

- (a) Except as provided in paragraph (f) of this section, for ~~flowback of each well completion operation with~~ immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) ~~through (a)(3)~~ of this section.
- (1) You must minimize the VOC emissions associated ~~with venting of hydrocarbon fluids and gas over the duration of~~ flowback duration of immediately following hydraulic fracturing stimulation that occurs at a natural gas wellhead facility onshore, as defined in §60.5430, utilizing one or more of the following ~~options: by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.~~
- (i) Route salable natural gas to a natural gas gathering line if available when deemed safe and practicable by the operator. When the well head pressure (in absolute units) immediately following perforation is four times the static sales meter pressure then the operator is obligated to flow the well to an available sales line or document the reasons for failing to flow to sales.
- (ii) Capture and route flowback emissions that cannot be directed to the gathering line to a completion combustion device except when conditions may result in a fire hazard, or explosion, gas is not combustible, or not allowed by state, tribal, or local requirement. Completion combustion devices must be equipped with a reliable ignition source over the duration of flowback but are not subject to §60.18. For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, reduce emissions by

using a completion combustion device when not precluded by one of the conditions described above.

(iii) Other methods that minimize VOC emissions associated with flowback immediately following hydraulic fracture stimulation.

~~(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.~~

~~(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.~~

- (b) You must maintain ~~a log~~ records for each well completion operation at each gas wellhead affected facility. ~~The log must be completed~~ on a daily basis and must contain the information ~~records~~ specified in §60.5420(c)(1)(iii).
- (c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by §60.5410.
- (d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by §60.5415.
- (e) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.
- (f) For wells meeting the criteria for wildcat, appraisal, or delineation wells or where production equipment or a natural gas gathering line is not reasonably available, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)~~(3)~~ (1)(ii) of this section. ~~You must also maintain records specified in §60.5420(c)(1)(iii) for wildcat or delineation wells.~~
- (g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f).

15.3. Need Ability to Combust or Vent

Paragraphs 60.5375(a)(1) and (2) require “routing recoverable liquids to storage vessels and routing the recovered gas into a gathering line or collection system” and “all salable quality gas must be routed to the gas gathering line as soon as practicable.” API appreciates that EPA is trying to provide flexibility in the proposed rule language, but additional clarity is needed in the rule to

address the many operational and safety constraints to routing all salable gas to gathering line. There are several operational and safety constraints that limit the ability to meet these requirements. These constraints include but are not limited to:

15.3.1. Lack of Availability of a Natural Gas Gathering Line and Production Equipment

Unless a well's probability of commercial productivity is almost assured, natural gas gathering lines and production equipment may not be installed prior to completion and it is unreasonable and not cost effective to require that they be installed to enable REC's. This limits the "footprint" as well as the financial risk associated with a well that may never produce. Non-producing wells are known as "dry holes". According to the US Energy Information Administration (EIA), in 2010 8.9% of total wells drilled were dry holes^F and approximately 39.2% of total exploration wells drilled were dry holes^G. Commercial viability of the well must be considered when requiring to route gas to a natural gas gathering line. The Wyoming Department of Environmental Quality "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance" revised March 2010^H only applied to concentrated development areas and the Jonah Pinedale Development Area of Wyoming, not to smaller development areas where reservoir extent, productivity, compositions, and pressures are not well established. Furthermore, in these concentrated development areas current development is "in-fill" drilling where the probability of success is almost assured, there is already sufficient natural gas production to justify the installation of a natural gas gathering line and the main gas gathering line/system is already in place. Permitting, designing, and installing a natural gas gathering system (including pipelines, compression, gas plant) takes a great amount of time and money. Sufficient natural gas production in the area is required to justify the cost and burden for permitting, designing, and building the natural gas gathering system. Companies may drill multiple wells prior to determining whether an area can be economically produced and justify the investment necessary. An exemption from sending natural gas to a natural gas gathering line should be extended to wells where commercial viability is not assured prior to installation of equipment and pipelines.

Before natural gas production can be sent to natural gas gathering line, all of following must be done:

- **A natural gas gathering line/system must be permitted, installed and operational in the area.** Permits are required for right-of-way, installation, compressor site air quality, etc. for the natural gas gathering line/system before it is installed which take much longer than getting a permit to drill a well. Designing and installing a natural gas gathering system (including a pipelines, compression, gas plant to send the gas to, etc) takes considerable time and money. Furthermore, designing and installing a gas

^F <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0407>

^G <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0406>

^H Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

gathering line depends on having enough natural gas production to justify the exceptional cost and burden for the gas gathering system.

- **A contractual right to flow into the gas gathering system with the company that owns the gathering line.** In most cases the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added.
- **Acquire necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system.** Permits and right-of-way are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary right-of-way can be difficult and require a court decision.
- **The natural gas must meet the specifications of the natural gas gathering line.** Contracts with the gathering company include specifications for entering the gas gathering line including concentrations of inert gases such as carbon dioxide or nitrogen, and H₂S. Carbon dioxide and nitrogen are often used to energize well stimulations to assist with flowback and cleanup. The carbon dioxide and nitrogen flowback and can not be routed to the pipeline because they make the gas not salable. The natural gas gathering system operator ultimately controls when an operator can send gas to sales.
- **There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well and not choke it.** This has been discussed in further detail under Section 15.3.2 below and Attachment F (Reservoir Performance) which is incorporated in these comments by reference.
- **The natural gas gathering line must be operational at the time of the completion.** Natural gas gathering lines can be down for a multitude of reasons including but not limited compressor maintenance or repair, line maintenance, line inspection, the gas plant being shut down, etc.

Furthermore, there are many reasons to complete a well and flowback without a natural gas gathering line or production equipment in place including but not limited to:

- **Avoiding lease jeopardy by establishing production in paying quantities.** Mineral leases contain expiration clauses tied to specific milestones to encourage the development of a lease hold in a timely fashion. One of the typical milestones is performance of a well completion. If the date is missed, the lease expires, causing the rights owner not only to lose the cost of the lease, but the investment in assessing the lease and preparing to drill it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to unavailability of REC equipment create an additional risk that the operator could fail to live up to steps in the contract and negate the contract causing the operator to lose their rights to the minerals.

- **Waiting for the necessary permits for installing the pipeline or the production equipment.** For major sources and minor sources in some states or on Tribal land, a permit for installing the production equipment must be obtained prior to construction of the source. Due to lease requirements, the well may have to be drilled within a certain time period as discussed above. If the air permit for collection system compression or the well site (if required) has not been obtained in time, the well could have to be drilled due to performance provisions in the lease agreement before the production equipment can be constructed. Furthermore, permits are needed to install the pipeline to connect to the natural gas gathering system. Time for approval of permits depends on the agency reviewing them and is out of the control of the company owning the well.
- **Not knowing the composition of gas limiting ability to design the production equipment or pipeline.** In some areas, the production equipment and pipeline are not installed until the composition of the gas is known in order to design the equipment to handle the gas and condensate, particularly for sour gas fields where the level of H₂S is critical for the design requirements. This is particularly significant in areas where the reservoir and properties are not well known and delineated.
- **Getting the surface rights for installing production equipment.** In many cases the owners of the mineral rights are different from the surface rights; therefore, surface rights must be obtained for construction of a pad to drill a well and subsequently install the production equipment. These surface rights are size/area limited and in many cases not sufficient to have in place both the completions equipment and the production equipment at the same time so companies wait to install the production equipment until after the drilling and completions equipment are gone. This also limits the “footprint” of surface disturbance to the area.

API requests that any well that does not have production equipment or a natural gas gathering line reasonably available based on when the well is flowed back should be able to be treated the same as a delineation or wildcat well under the rule and be able to combust or vent the natural gas. At a minimum, we would appreciate concurrence that the issued discussed above are conditions in which routing to a sales line are not practicable.

15.3.2. Pipeline Pressure

When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure and maintain adequate velocity to clean-up the well and reservoir. Any time this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline. This allows clean up of the well bore and is critical to minimize the potential for formation damage. It is possible that sensitive zones can lose productivity due to increased clean-up time required if back pressure is added to the well because of the line pressures. Once a fracture stimulation is pumped, flowback and cleanup must proceed regardless of sufficient pressure to enable sales or severe and permanent reservoir damage is likely. Adding compression to overcome line pressure on low energy wells has been tried several times and found to be not feasible for technical reasons. Furthermore it adds additional emissions for engines to power the compressors while greatly increasing the cost.

The Colorado Oil and Gas Commission requirements under 805(b)(3) are written to apply only to “on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater.” Based on conversations with industry and agency participants in the rule making, the threshold of 500 psig was based on ensuring the reservoir pressure was high enough to overcome the line pressure, clean out the well, and not choke the well based on the reservoir and line pressures within Colorado. Based on the wide range of variability across the US in reservoir and line pressures, setting a specific pressure threshold would be difficult. API recommends that any well whose reservoir pressure (measured at the wellhead immediately after perforation) is less than 4 times (in absolute units) line pressure measured at the flow meter would be exempt from any requirement to flow to sales during the flowback period. Please see Attachment F (Reservoir Performance) which is incorporated into these comments by reference for additional information.

15.3.3. Drilling Fracture Plugs and Running Tubing

Nitrogen may be added to the fluid stream when drilling fracture plugs to help assist flowback and debris removal. The nitrogen content prevents the gas from meeting pipeline specifications and may render the gas unable to support combustion. A well must be flowed while drilling out plugs to remove cuttings/debris and prevent “pack off” around the tubing which is likely to result in stuck tubing. Flow may be sent to a pit or flow-back tank and atmospheric pressure rather than sales to reduce back pressure to enable fracture-plug debris and sand to be more efficiently removed from the well. Furthermore, higher back pressures which may occur if “pack off” around the tubing occurs, may result in cross flow from high pressure zones to low pressure zones, which results in the inefficient cleanup of low pressure zones and may cause irreparable formation damage.

15.3.4. Hydrates and Maintenance

Pressure drops across a flow-back choke can initiate hydrate formation. The additional equipment and piping associated with flareless completions creates an even greater opportunity for hydrates (which form at elevated temperatures while the stream is at elevated pressure). Hydrate formation can plug the pipeline, wellhead equipment, or production equipment. If any of the components must be taken out of service, the well may be routed to the flare until the hydrate problems are solved and the system is back on line. Cold weather operations need additional flexibility to flare to prevent hydrates during clean-up operations.

15.3.5. Depressuring High Pressure Wells

Routing initial flow from a high pressured well to the sales line can create a safety issue. When there is a large difference between the well pressure and the sales line pressure, the decrease in pressure results in a significant temperature drop. This cold gas stream can cause the equipment to freeze up. Initial well flow after drilling or shut-in will be flared until the gas is warm enough to be routed to sales safely. Some companies require the use of a line heater to prevent freezing and choking the well.

15.3.6. Exempt Appraisal Wells from Going to Sales.

The proposed Subpart OOOO does not require reduced emissions completions for “wildcat” and “delineation” wells because such wells are “generally not in close proximity to a gathering line.” 78 FR 52745. These two terms are defined as follows:

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists

These terms probably work reasonably well in conventional oil and gas reservoirs to define the early stages in field development where a gathering system would not be expected to be present.

However, unconventional reservoirs such as shale gas reservoirs present different issues in determining whether infrastructure investment in gathering systems is appropriate. The issue is related to understanding well performance and ultimate well recovery. The decline of wells in unconventional reservoirs is not as well understood and most of the 'new' shale plays have only limited production history. It often takes several wells and significant production history before enough production data exists to properly characterize the well and area potential. Aside from the lesser degree of production history, shale plays have two other characteristics that may delay infrastructure investment:

- Horizontal wells are more costly to drill and prepare than typical conventional wells, so that good production history is important to determine if more wells are economically viable
- Shale reservoirs often have gradual gradients from oil to gas. Oil remains more valuable as a commodity than natural gas, so that one function of field appraisal is to find the economically viable areas of a shale reservoir, not its technical geologic boundary

API recommends adding “Appraisal wells” as a third category of well that is exempt from the REC requirements of §60.5375(a). The suggested definition shown below has been drawn from definitions used by the Energy Information Agency and other federal agencies such as the USGS and SEC.¹

Because the term “proved reserve” has an important regulatory and financial reporting meaning, companies have a very strong incentive to accurately report areas and amounts of proved reserves.

We believe this additional definition better reflects the universe of wells for which a gas gathering system will not be available. It also avoids a potential “chicken before the egg” problem where a shale play appraisal well system is effectively compelled to install a

¹ http://www.eia.gov/dnav/ng/TblDefs/ng_enr_shalegas_tbldef2.asp

gathering line system before the wells are determined to be economically viable, in order to assure compliance with NSPS Subpart OOOO.

Suggested Rule Text:

§60.5430

Appraisal well means a well drilled in an area where the reservoir has not been classified for that area as containing proved reserves of natural gas.

Proved reserves of natural gas are reserves which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas -- oil and/or gas -- water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

15.3.7. Allow for Venting Versus Flaring

The rule allows for venting in “conditions that may result in a fire hazard or explosion.” However, there are also times when the gas may not be burnable due to low BTU content from use of nitrogen or CO₂ in the fracturing operation which would require venting. Also, there are areas of the country that do not allow for the use of a combustion device due to fire hazard such as San Juan County, CO or areas where burn bans are put in place.

15.3.8. Allow For Electronic Igniters

The rule currently requires a completion combustion device with a “reliable continuous ignition device.” In many cases electronic igniters are used instead of a continuous ignition device. API requests that the rule be modified to explicitly allow the use of electronic igniters. (See Section 9.1.2 of general comments for more details.)

15.3.9. Completion Combustion Device Not Subject to §60.18

Section 60.5375(a)(3) provides that “You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.”

EPA appears to have chosen the term “completion combustion device” so that the pit flares, which the preamble states at p. 52758 are not a “traditional flare control device” would not be subject to §60.18. The preamble indicates that this is the case “because of the multiphase

slug flow and intermittent nature of the discharge of gas, water and sand over the pit.” As a result, pit flares cannot comply with the technical requirements of this section.

However, Subpart OOOO also includes a definition of flare at §60.5430 which reads as “*Flare* means a thermal oxidation system using an open (without enclosure) flame.” This definition would include pit flares because they use an open flame to oxidize the gas portion of the flowback. While pit flares are often used, some operators may choose to use temporary portable “field flare” flare devices or be required to do so by state or local rules. These temporary portable “field flares” may or may not be capable of meeting the full requirements of §60.18 and API requests that they receive the same exclusion from the requirements of §60.18 that are afforded to pit flares.

Suggested Rule Text:

§60.5430

Flare means a thermal oxidation system using an open (without enclosure) flame. [A completion combustion device is not a flare.](#)

Suggested Rule Text: Please see suggested rule text for §60.5375 under Section 15.2.

15.4. Availability of Equipment and Experienced Operators

Paragraph 60.5370(a) requires that “You must be in compliance with the standards of this subpart no later than the date of publication of the final rule in the Federal Register or upon startup, whichever is later.” EPA is required to complete the final rules by February 28, 2012 which is the deadline established in the consent decree EPA negotiated with WildEarth Guardians and San Juan Citizens Alliance. Obtaining the necessary equipment and experienced staff for reduced emissions completions (REC) is a significant issue as discussed below. The processes and equipment used for doing reduced emissions completions have taken industry over 10 years to develop and vary greatly depending on the reservoir type, gas composition, hydraulic fracturing medium used, etc. Currently most of the larger operators are employing REC where it makes economic sense; however, the majority of smaller and independent operators are not currently doing REC. As written, every gas well hydraulically fractured would require REC as discussed further in Attachment G (RIA Review), which is incorporated into these comments by reference.

Due to the limited availability of appropriate and safe equipment and experienced and trained personnel to perform REC's, API requests that compliance with the reduced emissions completions portion of the rule, except for routing gas to a completion combustion device, be delayed for 2 years to allow for manufacturing of equipment and training of operators. This delayed compliance date is necessary to ensure the implementation of safe equipment and practices and enable the ability of companies to comply with the proposed requirements. Under 40 CFR 60 Subpart A, Ja, AA, JJJ, and KKKK, EPA allowed for an effective date for compliance with the rule after the final rule was published in the federal register. The Wyoming Department of Environmental Quality allowed over a year from the time their “Oil and Gas Production Facilities Chapter 6, Section 2 Permitting

Guidance" revised March 2010^J was approved until permits were issued for reduced emissions completions to give all companies time to acquire the needed equipment and train operators on doing the completions for only part (concentrated development areas and the Jonah Pinedale Development Area) of the State of Wyoming. With the nationwide coverage of Subpart OOO the magnitude of the gap between current availability and necessary equipment and experienced personnel will be much larger and a longer delay will be required.

15.4.1. Availability of Equipment

With implementation of the rule required so quickly after the rule is finalized, equipment will not be available to meet these requirements. There is already a shortage of the specialty equipment required due to the recent WYDEQ BACT Policy and the expansion of the rule to all of the US will make this shortage unmanageable. It will take a significant amount of time for the vessel/equipment manufacturers to expand their capacity to manufacture adequate equipment which meets API and pressure-vessel code specifications in the quantities required to comply with the rule. Maintaining the current aggressive rule implementation schedule will force one of two outcomes:

- (1) The pace of drilling of new wells and recompletion of existing wells will be sharply reduced which will result in job losses, supply disruption, higher natural gas prices, and higher electricity prices.
- (2) In order to comply, companies will be forced to use or quickly manufacture/modify equipment which may not meet fabrication codes and standards and could be less safe to use.

In short, the current schedule contemplated by the rule is very likely to unnecessarily create unsafe conditions and operations or supply disruptions and job losses.

Today there is something on the order of 300 sets of REC equipment in existence. This equipment has the ability to process approximately 4,000 wells a year. To allow 20,000 wells to flow to sales in a year would require about 1,300 additional sets of equipment. This equipment is fairly specialized, the shops licensed to make it are limited, and some of the components require a long lead time. It should be expected with today's demand for other pressure vessels that it will be on the order of one year before the first set of additional equipment can be delivered. From that point, industry can probably deliver about 50 sets per quarter, so about 7.5 years will be required to meet the anticipated demand. For this reason, API also requests that the applicability be further limited and that the specific equipment not be specified as discussed further below. As discussed in Section 7.4, if the equipment is not available it does not constitute "the best system of emission reduction."

A related problem with meeting the equipment demand is the availability of capital to fund the necessary new equipment given the current economic conditions and credit availability. Manufacture of a single set of high-pressure code compliant REC equipment is expected to

^J Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

cost about \$467,000 per set. With the estimated 1,300 additional sets necessary this implies a capital investment in excess of \$600 MM to manufacture the equipment. The majority of the pressure vessel manufacturers are not large companies and will likely not commit the capital and effort to expanding the equipment base until the rule is finalized and detailed requirements are known. Even when the rule is finalized, detailed requirements known, and manufacturers chose to construct additional equipment they may not be able to access the funding required. This could further extend the time required for the necessary suite of equipment to be manufactured and deployed.

The current flowback language requires that this equipment must be available prior to stimulation even if it is known that the reservoir pressure/energy, pipeline pressure, and prior well behavior in an area preclude or make highly unlikely that a well can flow to sales. Requiring equipment on site even when it is known that REC's cannot be reasonably accomplished will unnecessarily exacerbate the equipment and personnel shortage problems with zero benefit while imposing unnecessary costs on the operators and ultimately the public. This unnecessary requirement will exacerbate the likely reduced well activity with the consequent job loss, lowering of gas supply, and raising of natural gas and electricity prices.

An additional potential economic harm is the requirements included in mineral leases. If the spud date of a well is delayed by very many months due to equipment availability, then there is a real risk that companies can find themselves in violation of leasing agreements that allow those agreements to be cancelled by the mineral owner. This "lease jeopardy" situation is a real danger in oil & gas operations and production companies take special pains to avoid it where possible. Requirements of REC will create a real risk that companies will lose leases that otherwise would have represented substantial value.

15.4.2. Availability of Experienced Operators

An additional significant concern with requiring implementation of the rule so quickly after the rule is finalized is that industry will have a shortage of experienced contractors or staff for complying with §60.5375(a) or doing "reduced emissions completions". Reduced emissions completions are very complicated and involve many safety issues/concerns with unique risks. The high pressure flow rates of fluids and sand can be quite dangerous. Inexperienced staff will not have adequate knowledge to properly manage the unique risks and prevent incidents from occurring. Industry will not have time to adequately train contractors or staff on how to safely do "reduced emissions completions" which again is likely to create unsafe conditions and operations.

Suggested Rule Text:**§60.5370**

- (a) You must be in compliance with the standards of this subpart no later than 60 days after the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later: ~~except for the provisions of §60.5370(a)(1)-(5) below:~~
- (1) Compliance with §60.5375 is required beginning [two years after the effective date]. From the [effective date] until [two years after the effective date] comply only with §60.5375(a)(1)(ii).

15.5. Timing of Requirements

EPA has stated during conference calls on the rule and at a meeting with API that it was EPA's intent that well completions at gas wellhead affected facilities commenced after the August 23, 2011 proposal date for NSPS OOOO where the completion was commenced before the effective date of the final NSPS OOOO ("Proposal Period Wells") did not require compliance with the emissions control requirements of §60.5375(a). This appears to be consistent with section 111(e) of the Clean Air Act, which reads as follows:

(e) After the effective date of standards of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source.

If the completion work is commenced before the effective date of the final rule, the owner or operator of an affected natural gas wellhead facility will not be operating the well in violation of the requirements of §60.5375 (or other provisions of Subpart OOOO that apply) after the effective date of the final rule. Thus, the requirements of Subpart OOOO do not apply to Proposal Period Wells. However, the applicability section of the rule is written as follows:

§60.5365 Am I subject to this subpart? If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart.

This can be read to require that Proposal Period Wells comply with the emissions control requirements of §60.5375. This concern is magnified by the recordkeeping requirements in §60.5420(c).

§60.5420 (c) Recordkeeping requirements. You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

- (1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).
- (i) Records identifying each well completion operation for each gas wellhead affected facility conducted during the reporting period;

- (ii) Record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.
- (iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section.

In particular, subparagraph §60.5420(c)(ii) appears to state that it is a “deviation” (i.e. a violation of Subpart OOOO) if Proposal Period Wells are not completed in accordance with the requirements specified in §60.5375(a)

To clarify the applicability of Subpart OOOO to Proposal Period Wells, API recommends that Section §60.5375 be amended to add a new paragraph (g):

Suggested Rule Text:

§60.5375

(g) The provisions of this section notwithstanding, a gas wellhead affected facility that commenced construction, modification, or reconstruction after August 23, 2011 but flowback immediately following hydraulic fracturing ends prior to [two years after the effective date] shall not be required to comply with §60.5375 (a) through (f).

Most of the recordkeeping provisions applicable to gas wellhead affected facilities are tailored to documentation of compliance with §60.5375(a). We are suggesting recordkeeping requirements for Proposal Period Wells which require documenting that the well is not required to comply with emissions control requirements in §60.5375(a). We have also suggested that owners and operators have until two years after publication of the final rule in the federal register or worst case 60 days after publication of the final rule in the federal register to comply with these reporting and recordkeeping obligations, so that owners and operators have a reasonable compliance period to provide these notifications and ensure that proper exemption documentation relating to Proposal Period Wells is in place after the effective date.

API believes that neither section 111(e) (set forth above) nor section 111(a)(2)^K prevent EPA from allowing Proposal Period Wells additional time after the effective date of NSPS OOOO to comply with reporting, recordkeeping and notification requirements^L. That is because these requirements are not standards of performance as that term is defined in section 111:

Section 111(a) For purposes of this section:

^K (2) The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

^L This comment is not intended to suggest that EPA lacks authority under Section 111 as a general matter to allow for compliance dates after the effective date of an NSPS rule. Other sections of API's comments discuss other requirements for which API believes additional time should be allowed for compliance after the effective date of NSPS OOOO.

- (1) *The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction.*

Thus, it is only the standard for emissions of air pollutants that is referenced in section 111(e). Reporting, recordkeeping and notification requirements are not, therefore, standards of performance so that section 111(e) need not be read to require compliance with these requirements on the effective date of NSPS OOOO. This appears to a distinction already recognized by EPA as general matter, since EPA already allows time after the effective date of rules to submit reports and notifications for other new sources.

15.6. Applicability Issues

Further clarity is needed in various parts of the rule text as to where reduced emissions completions applies.

15.6.1. §60.5365(a)

As discussed in Section 5.6.2 (modification) of the comments, §60.5365 states, “For the purposes of this subpart, a well completion operation refracturing that occurs at a natural gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the natural gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.” First, this general section is the wrong location for this text. It only adds confusion. At a minimum, it needs to be moved to §60.5365(a) which discusses the affected source. More importantly, it adds to the confusion of what the affected source is or should be. As discussed in Section 5.4.1, the affected source has been defined as the wellhead, when the emissions being regulated are emissions from the flowback immediately following hydraulic fracture stimulation. API believes that this contradiction will lead to decades of confusion and disagreements by regulators and industry alike. API believes that this contradiction must be eliminated by the consultation and supplemental proposal previously discussed. However, if EPA refuses to do so, then EPA should clarify its intent through a series of definitions and regulatory text revisions that makes its intent much more clear than does the proposed rule.

Currently, there is no time limit placed on “following” hydraulic fracturing or refracturing. Thus, as written, once a well has been hydraulically fractured, any subsequent well work could be subject to the reduced emissions completions requirements. Furthermore, it does not limit the applicability to the flowback immediately following hydraulic fracturing at a natural gas wellhead facility onshore. Also, EPA mistakenly states that the rule applies “before” August 23, 2011.

Suggested Rule Text: See suggested rule text for §60.5365 under Section 5.4.3

15.6.2. §60.5375

Under §60.5375, it states that “for each well completion operation with hydraulic fracturing” the operational procedures of reduced emissions completions applies. However, as with §60.5365, there is no time limit placed on “with hydraulic fracturing or refracturing” and could be interpreted that any subsequent well work could be subject to reduced emissions completions. Also, it does not limit the applicability to the flowback immediately following hydraulic fracturing. Furthermore, “gas wellhead” is never mentioned which could be interpreted that all hydraulically fractured wells, gas and oil, would be subject to these requirements.

Suggested Rule Text: See suggested rule text for §60.5375 under Section 15.2.4.

15.6.3. Definition of Modification

As discussed earlier in the comments, a “modification” should apply to flowback of a recompletion immediately following hydraulic fracturing that has a reasonable expectation to be greater than the original completion. Wells that are recompleted within the same reservoir/zone that was previously hydrofractured will necessarily have fewer emissions than previously experienced due to the depletion of reservoir pressure. However, a well that is recompleted in new reservoir may have more or less emission than in original completion operations. By including recompletion in the definition of modifications, EPA has exceeded the intent of the CAA. The definition of modification should remain under §60.14. However, if EPA chooses to define modification in this subpart, the recompletions portion of the definition of modification should be removed.

Suggested Rule Text:

§60.5430

Preferred Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

Alternative Option:

~~Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.~~

15.6.4. Gas Wellhead Applicability Only

Based on EPA's discussion in Section 4 of the Technical Support Document, it appears the EPA's intent is to require reduced emissions completions only for natural gas wells. However, the rule needs to include "natural gas" versus "gas" throughout as API has proposed for clarity. API supports that EPA applied reduced emissions completions only to natural gas wellhead facilities and excluded oil wellhead facilities and other types of gas wells which have little or no VOC emissions. As shown on page 4-13 on Table 4.4 "Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions" of the Technical Support Document, there are only 134 TPY of VOCs emissions from oil well completions and recompletions for the entire U.S., which is not worth regulating.

15.6.5. Offshore Applicability.

Based on the Technical Support Document and preamble for the proposed rule, it was clear that EPA did not assess the feasibility and cost for doing reduced emissions completions offshore. Without a pipeline being available nor space for the specified reduced emission completions equipment, it is not feasible to do REC offshore. Furthermore, many offshore rigs are often foreign flagged and will not necessarily be designed to accommodate or achieve US regulatory requirements. Therefore, API request that reduced emissions completions only apply to onshore facilities.

Suggested Rule Text : See suggested rule text for §60.5365 under Section 5.4.3, for §60.5375(a) under Section 15.2.4, and for the definition of a modification under Section 15.6.3 above.

15.7. Multiple Notification Requirements

The rule as proposed is requiring four notifications for every well completion operation following hydraulic fracturing or refracturing at a gas well head facility which include:

- Post-marked 30 days after construction [§60.7(a)(1)],
- Post-marked 15 days after initial startup [§60.7(a)(3)],
- Post-marked 60 days or as soon as practicable before the changed is commenced [§60.7(a)(4)], and
- 30 days of the commencement of the well completion operation [§60.5410(a)(1) or §60.5420(a)(2)].

Furthermore, EPA requested comment on a "follow-up notification one or two days before an impending completion via telephone or by electronic means" which would mean five notifications for every completion operation. EPA predicted 20,000 hydraulic fracturing and refracturing events per year resulting in greater than 100,000 notifications per year. These multiple notifications will be excessively burdensome on both the Administrator and industry with no benefit to air quality. Industry would need full time employees to just do all these notification and re-notifications. EPA

solicited many comments on the notifications for completions on pages 52749-52750 of the Federal Register. In response to EPA's questions, API proposes the following changes.

15.7.1. Remove Subpart A Notifications

API requests that all the §60.7(a) notifications be removed since they are not appropriate for completions operations. The definitions of both "construction" and "initial start-up" do not apply to the flowback immediately following hydraulic fracturing. The flowback is a temporary operation that lasts only "3-10 days" as discussed in the preamble. Furthermore, predicting 60 days in advance of doing a completion operation is not possible. Even drilling of the well would not necessarily have even been started 60 days prior to the completion operation so predicting when the completions event would begin is even more difficult to predict. The timing for the flowback portion of the completions operation depends on the drilling schedule, availability of the drilling equipment, the time to drill the well, the schedule for the completion, the availability of the equipment for casing the well and running tubing, the schedule for casing the well and running tubing, the schedule for fracturing, the availability of the hydraulic fracturing equipment, the time to fracture the well, the number of fracture stages (individual or multi-stage), etc.

15.7.2. Remove the Notification to EPA 30 Days Prior to a Well Completion Operation or Change as Proposed

Paragraph 60.5420(a)(2) requires that you must submit a notification to the Administrator within 30 days of the commencement of the well completion operation. The notification must include the date of commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983." Based on the preamble and discussions with EPA, it is API's understanding that the intent was that notification be given to EPA 30 days prior to the doing a completion so that the Administrator could attend. Predicting a completion 30 days prior to its occurrence is extremely difficult as discussed above. In many cases the well may not have begun to be drilled. The actual date of the flowback depends on a multitude of factors as discussed above. EPA acknowledged this issue in the preamble stating "We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance" (pg. 52749-52750 of the FR). API requests that this notification requirement either be removed or reduced to a monthly report of the well completions scheduled to occur during the upcoming month. The notification could provide the tentative scheduled date for the start of the flowback immediately following hydraulic fracturing that will occur in the following month. The Administrator could contact the company with questions to request or more up-to-date timing of the flowback operations if needed. This would minimize the burden for reporting for each flowback operation for operators and give the Administrator a plan of the operations for the month ahead. Follow-up notification two days in advance seems excessive. With operations lasting 3-10 days, this should allow the Administrator sufficient time to attend part of the flowback operation.

Suggested Rule Text:

§60.5410

- (a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.
- (1) You have notified the Administrator monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month in which you have one or more hydraulic fractures scheduled, including within 30 days of the commencement of the well completion operation, the tentative scheduled start date of the well flowback and commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

§60.5420

- (a) You must submit the notifications required ~~in §60.7(a)(1), (a)(3) and (a)(4), and~~ according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in §60.5365. ~~For the purposes of this subpart, a workover that occurs after August 23, 2011-2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under §60.7(a)(4).~~

* * * * *

- (2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator monthly of all the well flowbacks immediately following hydraulic fracturing stimulation that are scheduled to occur at any gas wellhead facilities onshore during the upcoming month in which you have one or more hydraulic fractures scheduled~~within 30 days of the commencement of the well completion operation~~. The notification must include the tentative scheduled start date of the well flowback and commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

15.8. Clearer Definitions

The definitions for gas well, crude oil, well completions, well completions operation, and hydraulic fracturing in the rule are unclear and inconsistent with common industry understanding. Also, the definition of flowback should be edited as discussed in Section 5.4.2, and a definition should be added for well recompletion.

15.8.1. Definition of Gas Well

The definition of a gas well is unclear. "*Gas well means a well, the principal production of which at the mouth of the well is gas.*" The phrase "mouth of the well" is not a term used or defined in the industry, by the EIA, or commonly understood. For consistency with 40 CFR 98 Subpart W of the GHG Mandatory Reporting Rule and the EIA definition of a "gas well", API recommends using the definition of a gas well from 40 CFR 98.238 (which is based on the EIA definition) of "*Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.*"

Suggested Rule Text:

§60.5430

Gas well means a well, ~~the principal production of which at the mouth of the well is gas.~~ completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

15.8.2. Definition of Crude Oil

The definition of crude oil that EPA uses in the proposed rule conflicts with the definition of crude oil used in the Greenhouse Gas Mandatory Reporting Rule 40 CFR 98 Subpart W, by the EIA, and most states. The API gravity is not known for a well at the time a well is completed; therefore, with the definition of a gas well including crude oil and the definition of a gas well determining applicability for REC, the definition of crude oil should not contain an API gravity. API, therefore, recommends that EPA use the definition of crude oil from the EIA^M. This definition is also consistent with the definition of crude oil used in the Greenhouse Gas Mandatory Reporting Rule 40 CFR 98 Subpart W.

Suggested Rule Text:

§60.5430

Crude oil means ~~crude petroleum oil any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.~~ a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of non-hydrocarbons produced with the oil.

^M http://www.eia.gov/dnav/pet/TblDefs/pet_crd_pres_tbldef2.asp

15.8.3. Definition of Well Completions

Under §60.5430 a well completion is defined as “the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment.” Flowback of the well after hydraulic fracturing is potentially part of a well completion but a well completion may involve other activities such as perforating the production casing, stimulating the reservoir, and installing wellbore equipment such as tubing, packers, or liquid-lift tools.

API suggests the following definitions for well completion and well completion operations:

Suggested Rule Text:

§60.5430

Well Completions means the process ~~that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment~~ of making a new oil or natural gas well ready for production. It allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics and also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture stimulate and prop open new fractures in lower permeability reservoirs.

Well Completion Operation means any well completion ~~or well workover~~ occurring at a gas wellhead affected facility onshore.

15.8.4. Definition of Hydraulic Fracturing

The definition used for hydraulic fracturing is inconsistent with standard industry understanding. API recommends the following definition that is based on the definition of hydraulic fracturing in the Schlumberger Oilfield Glossary^N.

Suggested Rule Text:

§60.5430

Hydraulic fracturing means ~~process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that~~

^N <http://www.glossary.oilfield.slb.com/>

~~involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers~~ [a stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a fracture\(s\) to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.](#)

15.8.5. Definition of Flowback

As discussed in Section 5.4.2, to help prevent confusion of what is being regulated under §§60.5365(a) and 60.5375, API recommends that discussions of well completions and recompletions should only be included in the definition of flowback to prevent confusion of what is being regulated.

Suggested Rule Text:

§60.5430

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. [Flowback immediately following hydraulic fracture stimulation may occur in conjunction with a well completion, well recompletion, or fracture stimulation of the same zone in an existing well.](#)

15.8.6. Add Definition for Well Recompletion

The current proposed rule does not define *well recompletion*. This term has been included in the suggested revisions to the rule text. Therefore, API suggests the following definition for well recompletion be added to the proposed rule text.

Suggested Rule Text:

§60.5430

[Well Recompletion means completing a well again. See the definition of well completion.](#)

15.9. Remove the Requirement to Record the Distance to the Nearest Gathering Line

Paragraph 60.5420(c)(1)(iii)(B) requires that “For each gas wellhead affected facility required to comply with the requirements of §60.5375(f) “you must record the distance, in miles, of the nearest gathering line.” This could take an excessive amount of work to determine and provides no benefit to air quality. Before natural gas production can be sent to natural gas gathering line, all of following must be done as discussed in more detail under Section 15.3.1:

- A natural gas gathering line system must be permitted, installed and operational in the area a reasonable distance from the well.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must be in place.
- The necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system must be obtained.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well against the pipeline pressure without lowering the flow and velocity to the point where the well will not adequately clean-up.
- The natural gas gathering line and system must be operational at the time of the completion.

Suggested Rule Text:**§60.5420**

~~(c)(1)(iii)(B) For each gas wellhead-affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.~~

15.10. Emission Rates and Economics Are Unrealistic

Based on API's analysis, the data presented by the EPA for the cost effectiveness of reduced emissions completions does not take in account great variability of the VOC content of the gas, the flow rate of the gas, equipment needed for reduced emissions completions, etc. to adequately address requiring reduced emissions completions for all hydraulically fractured wells. Due to the vast variability, determining a threshold for cost effective reduced emissions completions is extremely difficult. EPA has looked at small subset of wells for the RIA which does not fully represent the diversity of wells across the US that are hydraulic fractured. Please see Attachment G (RIA Review) for more details. API estimates that the average cost per ton of VOCs without sales is \$33,748 versus EPA's estimate of \$1,516 and cost per ton of VOCs with sales is \$27,579 versus EPA's net gain of \$99. The overall cost to the industry for doing REC in 2015 would be \$782.6 Million versus EPA's benefit estimate of \$20.2 million.

15.10.1.EPA's Overestimate of Completions Emissions

In the preamble EPA stated "we estimate that uncontrolled well completion emissions for a hydraulically fractured gas well are approximately 23 tons of VOC, where emissions for a conventional gas well completion are around 0.12 tons VOC." Many of the formations currently being developed have very low concentrations of VOCs in the gas, particularly for some shale gas and coal bed methane formations.

An article published in *Oil & Gas Journal* March 9, 2009 titled "Compositional variety complicated processing plans for US shale gas" written by Keith A Bullin and Peter E Kroushop both of Bryan Research and Engineering had a series of tables that are summarized below:

Table 15-1. Average Compositions of US Shale Gas

Area	C1	C2	C3+	CO2	N2
Barnett Average	86.8%	6.7%	2.0%	1.7%	2.9%
Marcellus Average	85.2%	11.3%	2.9%	0.4%	0.3%
Fayetteville Average	97.3%	1.0%	0.0%	1.0%	0.7%
New Albany Average	89.9%	1.1%	1.1%	7.9%	0.0%
Haynesville Shale Average	95.0%	0.1%	0.0%	4.8%	0.1%
Shale Gas Average	90.8%	4.0%	1.2%	3.1%	0.8%

One API member furnished an average VOC content for coal bed methane wells (1,190 analyses) in the SW Colorado (Durango area) San Juan Basin area which indicates the following composition:

Table 15-2. Average VOC Concentrations of Coal Bed Methane Wells in SW Colorado

	C1	C2	C3	IC4	NC4	IC5	NC5	C6	CO2	N2
Mole %	94.694	0.332	0.062	0.010	0.009	0.002	0.001	0.002	4.330	0.280
Weight %	87.694	0.576	0.159	0.034	0.031	0.009	0.006	0.010	11.027	0.453

As these data illustrate, the variability of VOC content is broad and EPA's assumption of "average" VOC content is both high and does not reflect many of the producing areas. Consequently, EPA's analysis of cost per ton of VOC emissions controlled is both high and does not reflect the reality of gas compositions. For example, a 3 day flow-back period for a well with the Durango area average composition and EPA's assumed flow-back volume of ~9,175 mscf of gas would reduce VOC emissions by about 900 lbs at an EPA estimated risked cost of \$33,237 (~\$72,500 per ton) with no condensate recovery and a more likely maximum recovery of ~70%. With a 70% recovery the VOC reduction would be ~ 0.36 tons with an EPA estimated cost of \$33,237 and a total product sales revenue of ~ \$25,692 or a net cost of ~\$21,163/ton of VOC reduced which is clearly economically unreasonable. Given that API's analysis predicts sharply higher costs, lower overall volumes, and lower (<90%) recovery than EPA's estimate the costs of applying REC's to a well in the Durango area would approach \$500,000 per ton.

API requests that the final regulation include an applicability cut-off of 10% VOC by weight as discussed in Section 5.1.2. Actual data shows emissions range from 0 to 156 tons per flowback depending on the volume of the gas in the flowback, the VOC concentration, etc. (see Attachment G (RIA Review) for more details). However, the average emissions for shale gas wells are only 5.334 Tons of VOC per flowback. As the Tons of VOCs per

flowback drops to zero, the cost for doing reduced emissions completions per ton goes to infinity.

15.10.2. Cost of “Reduced Emissions Completions”

The estimated cost per well to do reduced emissions completions ranges from ~\$30,000 - \$200,000 per well according to an API survey depending on whether equipment is rented or owned, the equipment required, the time need for having the equipment on site, etc. (see Attachment G for details). In the preamble, EPA stated that, “Typical well completions last between 3 and 10 days and costs of performing REC are projected to be between \$700 and \$6,500 per day, including a cost of approximately \$3,523 per completion event for the pit flaring equipment.” This grossly underestimates the cost. The cost estimate per day in the RIA is reasonably close to the numbers reported in the API survey reported in Attachment G, but the RIA assumes that the equipment rental begins the very first day that it is needed and ends the last day of the flowback. This is unrealistic. The manpower and equipment required for completion events represent valuable resources that are in short supply. It is not normal practice to have stimulation equipment and personnel waiting for equipment installation. The respondents to the survey place the elapsed time for REC rental at 30 days more or less. So, for \$5,000/day a 30 day rental represents a \$150,000 outlay. Further, work around an active well site is very expensive. The respondents in the API survey estimated that mobilization/demobilization and operations of REC equipment adds approximately \$30,000 to the cost of the flowback. API estimates that a REC evolution to sales would add \$180,000 to the cost of the well. For low VOC wells, this additional cost represents a cost effectiveness that can be hundreds of thousands of dollars per ton. On CBM wells and those shale gas wells with very low VOC, the cost effectiveness can approach infinity. Production companies may have economic incentives to flow the well back to sales, but those incentives do not include a cost-effectiveness of VOC emission avoidance. A detailed economic analysis will be submitted later; however, the preliminary results indicate that the cost is much higher than EPA estimated.

15.11. Over Estimate of Number Re Completions per Year

In the TSD, EPA states that “10 percent of the wells being re-fractured annually (as previously assumed in Subpart W’s Technical Supporting Document³). From anecdotal information, API understands that this 10% re-fracture frequency per year was originally from work underlying the National Inventory and was developed based on one paper which evaluated the post re-stimulation performance of five (5) wells in the Barnett shale area which was then extrapolated to the population of unconventional wells nationwide. Obviously relying on extrapolation of somewhat unrelated information on five (5) wells in one area and one formation to the nationwide population of unconventional wells is completely unsupportable. API requests that EPA fully and completely explain the derivation of the 10% re-stimulation frequency per year rather than simply referencing the technical support document for Subpart W which simply makes the 10% assumption with no explanation or backup information. As the largest single reduction category in the proposed rule, this explanation is necessary to reasonably support EPA’s analysis.

According to a 1996 study by the Gas Research Institute (GRI)^O, only 2-3% of wells are refractured. This study found that only 15% of the well populations are potentially high potential restimulation candidates which should be subjected to additional analysis. Another study done in 1999 that was presented in a paper at a Society of Petroleum Engineers conference^P, showed that further analysis must be done to determine whether these 15% would actually benefit from restimulation. This paper presented an analysis of some 300 tight sand wells which had originally been hydraulic fracture stimulated, high-graded the top 15% of candidate wells for further evaluation and ultimately reduced the wells recommended for restimulation to five (5) of which 2 had been restimulated at the time the paper was written. In other words, only a small number (~2% of the total wells) of the top 15% candidate wells would actually be economic to restimulate anytime in their life. Other developing information suggests the percentage of wells refractured annually is less than 1%. Applying a 1% re-stimulation rate per year rather than a 10% would reduce the projected number of affected units to ~1,205 rather than 12,050 (90% reduction) and reduce the emissions reductions by the same magnitude.

16. STORAGE VESSELS

16.1. Applicability

There is considerable ambiguity under both Subpart OOOO and Subpart HH as to the population of storage vessels to which these rules are intended to apply. API requests EPA clarify that the boundaries listed below apply to the storage vessel provisions. Each of these issues is discussed more fully in the paragraphs that follow.

- **Storage vessel properly defined.** That is, defined as stationary vessels constructed of non-earthen materials, and which are distinct from process tanks.
- **Located in the oil and gas production source category.** That is, located upstream of the point of custody transfer between the production field and the liquid distribution pipeline.
- **Storing crude oil or condensate.** That is, storing only produced petroleum liquids.
- **Containing the regulated pollutant.** That is, storing liquids from which the regulated pollutant is emitted at greater than de minimis levels.
- **Having emissions above a cost-effective threshold.** That is, regulating emissions only for those storage vessels for which the controls would be above a cost-effective threshold under Subpart OOOO.

^O Reeves, S.R.: "Assessment of Technology Barriers and Potential Benefits of Restimulation R&D for Natural Gas Wells", Final Report, GRI- 96/0267, July, 1996.

^P Reeves, S.R., Hill, D.G., Tiner, R.L, Bastian, P.A, Conway, M.W. and Mohaghegh, S.: "Restimulation of Tight Gas Sand Wells in the Rocky Mountain Region", SPE 55627, Proceedings of the SPE Rocky Mountain Regional Meeting, Gillette, May 15-19, 1999.

16.2. Storage Vessel Definition [OOOO & HH]

The term “storage tank” or “storage vessel” should be defined in a manner that is consistent with other rules, while acknowledging the particular scenarios unique to the oil and gas production sector. Existing EPA regulations establish several features that distinguish a storage vessel (tank):

- The function of a storage vessel is storage, which distinguishes storage vessels from process vessels or tanks.
- A storage vessel is stationary, which distinguishes storage vessels from containers, vessels attached to mobile vehicles, and other vessels that are placed temporarily.
- A storage vessel is constructed of non-earthen materials, which distinguishes storage vessels from surface impoundments and underground caverns.

16.2.1. Process Tank

Activities identified as process functions in other regulations include:

- Reactions and blending.^Q
- Collection of material discharged from a process prior to transfer to other equipment within the process or to a storage vessel.^R
- Surge control.^S
- Bottoms receiver.^T
- Knock-out.^U

16.2.2. Stationary

The stationary aspect of a storage vessel is typically addressed by EPA in terms of whether or not it is reasonably portable. One issue in the consideration of portability is the size of the vessel, which is sometimes addressed by EPA in regulations pertaining to storage vessels.

Another criterion specified by EPA in several regulations is that “vessels permanently attached to motor vehicles” are not storage vessels, and EPA has issued a determination^V that this exemption extends to tanks “equipped with a permanently attached wheel assembly and a truck hitch.” This renders most so-called frac tanks, Baker tanks, ISO tanks, *etc.* exempt from the storage tank provisions when this form of definition is used.

API recognizes, however, that such tanks sometimes become effectively “stationary” in oil and gas production operations, and that it may be appropriate to apply a time limitation to

^Q From the definition of a Process Tank, 40 CFR 60.111b, added to Subpart Kb Standards of Performance for Volatile Organic Liquid Storage Vessels with the October 15, 2003 rule amendments.

^R Ibid.

^S Ibid.

^T Ibid.

^U From the preamble to the October 15, 2003 amendments to Subpart Kb (68 FR 59328).

^V U. S. Environmental Protection Agency, letter from George T. Czerniak to Ken Comey, Flint Hills Resources L.P., September 2, 2004.

this exemption. We therefore suggest that storage vessels should be deemed stationary if they remain at a given site for more than 180 consecutive days, consistent with the period of time allowed under §60.14(g) to achieve compliance after a modification. As a point of comparison, the definition of non-road engines in 40 CFR 89.2 states:

“(2)(iii) the engine otherwise included in paragraph (1)(iii) of this definition remains or will remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph does not apply to an engine after the engine is removed from the location.”

Given this precedent for the term stationary to not apply until a source has remained in place for at least 12 consecutive months, API's request that stationary not apply to a storage tank at an oil and gas production site until it remains in place for only 180 days is a modest and reasonable request.

Finally, cost effectiveness of the proposed control measures has been evaluated under the assumption that storage vessels remain in place for the useful life of the control equipment, and thus the control costs are amortized over a period of years. The cost per ton of emission reductions would obviously be much higher if the controls were applied to a tank that is only on site temporarily, in that the total cost of controls would be applied to emission reductions achieved over only 180 days, rather than over a period of years. It is clear, then, that a cost-effectiveness analysis for permanent storage tanks would not be valid for temporary storage tanks, and thus the control requirements for permanent storage tanks are not justified for temporary storage tanks.

16.2.3. Non-earthen

This is self-explanatory. Certain EPA regulations add the phrase “such as wood, concrete, steel, fiberglass, or plastic”^W as a parenthetical explanatory clause.

Suggested Rule Text:

We request that the following definition of “storage vessel” be used in both OOOO and HH:

§60.5430 and §63.761

[Storage vessel or Tank means a stationary unit that is constructed primarily of nonearthen materials \(such as wood, concrete, steel, fiberglass, or plastic\) which provide structural support](#)

^W U.S. Environmental Protection Agency, “National Emission Standards for Storage Vessels (Tanks)–Control Level 2,” 40 CFR Part 63, Subpart WW.

and is designed to hold an accumulation of liquids or other materials. Storage vessel or Tank does not include:

(1) Vessels with a design capacity less than or equal to 472 barrels^X storing a volatile organic liquid with maximum true vapor pressure less than 11.1 psia.

(2) Process tanks, including vessels used for a process function such as reactions, blending, or separation, vessels such as sumps used to collect discharged material such that it can be transferred to a process or to storage, vessels used for surge control, and vessels used as knockouts,

(3) Vessels storing wastewater,

(4) Pressure vessels designed to operate without emissions to the atmosphere,

(5) Subsurface caverns and porous rock reservoirs, and

(6) Vessels that do not remain at a given site for more than 180 consecutive days.

16.3. Located in the Oil and Natural Gas Production Source Category

As discussed in Section 3, there is unnecessary ambiguity in the applicability of the proposed rules with respect to storage vessels. The rules need to clearly specify the boundaries of the source category, identify the affected facilities within that source category, and specify which of the affected facilities are subject to the control requirements. Part 60 Subpart Kb and Part 63 Subparts HH, HHH, and EEEE each describe the boundary between the oil and natural gas production sector and the transportation sector as being where oil or natural gas is transferred from production or producing operations to “pipelines or any other forms of transportation.”

It is evident that the oil and natural gas production sector has been historically understood as being distinct from the transportation sector, but Subpart OOOO fails to delineate the sector to which the storage vessel provisions apply. Furthermore, EPA has proposed removing the distinction of “prior to custody transfer” from NESHAP HH, thereby unnecessarily obscuring the boundaries that had been previously established. These ambiguities should be addressed by restoring the source category boundaries to the manner in which they have been historically understood.

16.3.1. NSPS OOOO – Storage Tank Location

While the Subpart OOOO provisions for several types of emission points specify the locations at which the rule applies (e.g., applicability to compressors is specified as being between the well head and the city gate, both of which are defined terms), the applicability section contains no such language to stipulate boundaries for the storage vessel provisions.

^X A capacity threshold of 75 cubic meters (472 barrels) is specified in 40 CFR Part 63 Subpart BBBBBB—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR Part 63 Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), and 40 CFR Part 60 Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

In fact, the provisions simply specify that they apply to storage vessels, with no discussion of what industry sector the storage vessels may be located in.

Paragraph §60.5395(b) addresses overlap of Subpart OOOO with Subpart HH, and the definition of a storage vessel makes reference to a well site, so it might be inferred that applicability of the rule is limited to the production field, but the language is simply not clear. The definition of a storage vessel in Subpart OOOO limits the applicability for storage vessels that are not manifolded together to those located at a single well site. But there is no such qualifier for storage vessels that are manifolded together. Furthermore, the terms “manifolded together” and “single well site” are not defined, and their meaning is not evident.

API requests that EPA clarify the population of storage vessels to which NSPS OOOO is applicable as those located in the production field, prior to the point of custody transfer to the liquids distribution system. This may be accomplished by:

- Replacing the definition of “storage vessel” with the language suggested above (see below for mark-up of EPA’s proposed rule language), and
- Clearly specifying the intended applicability of the storage vessel provisions in the description of the affected facility, at §60.5365(e). This paragraph should specify that applicability is to storage vessels located prior to the point of custody transfer to pipelines or other forms of transportation.

Suggested Rule Text:

§60.5430

Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.

Storage vessel or Tank means a stationary ~~vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy.~~ unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials.
Storage vessel or Tank does not include:

(1) Vessels with a design capacity less than or equal to 472 barrels storing a volatile organic liquid with maximum true vapor pressure less than 11.1 psia.

(2) Process tanks, including vessels used for a process function such as reactions, blending, or separation, vessels such as sumps used to collect discharged material such that it can be transferred to a process or to storage, vessels used for surge control, and vessels used as knockouts.

- [\(3\) Vessels storing wastewater,](#)
- [\(4\) Pressure vessels designed to operate without emissions to the atmosphere,](#)
- [\(5\) Subsurface caverns and porous rock reservoirs, and](#)
- [\(6\) Vessels that do not remain at a given site for more than 180 consecutive days.](#)

§60.5365

* * * * *

- (e) A storage vessel affected facility, which is defined as a single storage vessel [storing condensate or crude oil and located prior to the point of custody transfer.](#)

16.3.2. NESHAP HH – Storage Tank Location

As noted above, the original version of Subpart HH specifies that applicability is limited to storage vessels located prior to the point of custody transfer to pipelines or other forms of transportation. The proposed revisions to §63.760(a)(2), however, would remove that point of demarcation, and instead specify that the rule applies to facilities “prior to the point where hydrocarbon liquids enter either the Organic Liquids Distribution (Nongasoline) or Petroleum Refineries source categories.” While this wording has the apparent intent of preserving the boundary between the production field and the liquids distribution system, the reference becomes circular in that the Organic Liquids Distribution MACT rule (Part 63 Subpart EEEE) specifies that it excludes facilities subject to Part 63 Subpart HH (see §63.2334(c)(1)). Thus the revisions to Subpart HH would result in each rule excluding the affected facilities of the other, but neither rule defining the boundary between the source categories. In order to preserve a specified boundary, the wording of §63.760(a)(2) should continue to specify the point of custody transfer as the demarcation between the production field and transportation sectors. Further clarity would be achieved by replacing the former definition of “custody transfer” with the suggestion shown below (as suggested for NSPS OOOO above).

Suggested Rule Text:

§63.761

[Custody transfer means the last point of custody transfer of crude oil, condensate, or natural gas before it leaves the production field or basin and enters pipelines or any other forms of transportation. Typical custody transfer points include truck loading facilities or pipeline metering stations for crude oil or condensate, and the tail gate of natural gas processing plants or pipeline metering stations for natural gas.](#)

§63.760

- (a)(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer ~~where hydrocarbon liquids enter either the Organic Liquids Distribution (Non gasoline) or Petroleum Refineries source categories.~~

16.4. Storing Crude Oil or Condensate

API believes that EPA intends the storage vessel requirements to apply only to tanks storing crude oil or condensate, but this intent is not adequately specified in the regulations.

16.4.1. NSPS OOOO – Crude Oil and Condensate

It seems, from the preamble, that EPA intends for these rules to apply only to tanks storing crude oil or condensate. However, the rules do not expressly specify the stored liquids to which the rules are applicable. On the one hand, one might infer from §60.5395(a) that Subpart OOOO applies only to tanks storing crude oil or condensate. On the other hand, the language could be construed to extend applicability to any storage vessel storing any liquid whatsoever, unless the vessel is storing crude oil or condensate and the throughput is below the specified cutoffs (in that the language does not address the situation if the vessel is storing something other than crude oil or condensate). API requests clarification that the storage vessel provisions of Subpart OOOO are applicable only to tanks storing crude oil or condensate.

Suggested Rule Text: See suggested rule text for §60.5365(e) under Section 16.3.1.

16.4.2. NESHAP HH – Crude Oil and Condensate

The MACT Floor memo for Subpart HH, in the discussion of storage tanks, indicates that the EPA survey was representative of “tanks that have the potential for air emissions to occur.” It then states, “Significant HAP emissions can occur due to flashing, and due to breathing and working losses from tanks containing volatile organic liquids such as condensates or volatile oils.”^Y The “volatile oil” produced in the oil and natural gas production source category is, of course, crude oil. It seems readily evident, then, that the storage vessels in this source category are those located in the production field which store condensate or crude oil. API requests clarification that the storage vessel provisions of Subpart HH are applicable only to tanks storing crude oil or condensate.

Suggested Rule Text:

§63.760

(b)(1)(ii) Each storage vessel [storing condensate or crude oil and located prior to the point of custody transfer](#);

16.5. Containing the Regulated Pollutant

EPA's authority to extend applicability of a regulation to a given facility is predicated on that facility being reasonably considered a source of the regulated pollutant. EPA has recognized this by use of the term “in VOC service” with respect to NSPS regulations, and “in organic HAP service” or “in

^Y Memorandum from G. Fitzsimons and G. Viconovic, EC/R, to M. Smith, EPA, “Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category,” September 23, 1997, page 9, section 3.2, third paragraph.

VHAP service” for NESHAP regulations. This is not a matter of requesting an exemption for facilities that are sources of the regulated pollutant, but rather it is a matter of recognizing that below certain *de minimis* thresholds of concentration, a facility is not reasonably deemed a source of that pollutant and thus is not part of the source category.

16.5.1. In VOC Service [NSPS OOOO]

Subpart OOOO, at §60.5400(f), specifies “For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight.” The same statutory authority applies to other types of emission sources as to “equipment,” and thus this requirement of being “in VOC service” should qualify applicability of the rule to every type of emission source. We note, however, that this qualifier would be moot if EPA were to clarify that Subpart OOOO is applicable only to storage vessels storing crude oil or condensate, in that those liquids would always exceed the 10% threshold.

16.5.2. In VHAP Service [NESHAP HH]

Similarly, Subpart HH defines the term “in VHAP service” as involving a total volatile HAP concentration equal to or greater than 10% by weight. Subpart HH presently applies this term only to ancillary equipment and compressors. API requests that this term also be applied in the determination of applicability of Subpart HH to storage vessels, in that EPA is not required to regulate *de minimis* sources of HAPs.

Revision of the rule language to clarify that the rule is applicable to storage vessels that are “in VHAP service” would ensure that applicability of the rule is practicable and effective. As with the issue of “in VOC service” noted above, however, this comment on “in VHAP service” would likely be rendered moot if EPA were to clarify that Subpart HH is applicable only to storage vessels storing crude oil or condensate.

16.6. Having Emissions Above a Cost-Effective Threshold [NSPS OOOO]

EPA has proposed thresholds for applicability of the Subpart OOOO storage vessel provisions on the basis of cost effectiveness. However, both the use of throughput as a surrogate for VOC emissions and EPA's cost-effectiveness analysis are flawed. Also, while we endorse the concept of limiting applicability to tanks that emit more than 10 tpy, we believe that this limit should be specified in the storage vessel provisions rather than in the definitions, and the limit should be 12 tpy (as documented below).

16.6.1. EPA's Emission Rate versus Throughput is Not Credible.

In the preamble VI.B.4.d, EPA states that the emission factors used to establish thresholds for requiring storage vessel controls are from a Texas Environmental Research Consortium (TERC) study. This study H051c, *VOC Emissions from Oil and Condensate Storage Tanks*, calculated emission factors based on observations made during three summer months in 2006 of 11 crude oil tanks and 22 condensate tanks in East Texas. The report calculated an

emission rate as a function of throughput of 33.3 lb/bbl +/- 24.3 lb/bbl for the condensate tanks and 1.6 lb/bbl +/- 1.6 lb/bbl for the crude oil tanks.

We believe the methodology used in the report is flawed for the following reasons.^Z

- A. It is obvious that gross errors in measurements occurred for tank battery #25. Both the reported vent gas molecular weight of 89 and the VOC fraction of 0.99 are impossible values for gas flashed from condensate at a natural gas production site. The calculated VOC flash emissions of 215 lb/bbl would require that 82% of the condensate flashed when reduced in pressure from 200 psig. This is not possible at this separator pressure. Rejecting this data point and recalculating the average VOC emissions from the remaining tank batteries would give a factor of 24.2 lb/bbl, 73% of 33.3 lb/bbl.
- B. For tank battery #17, the calculated VOC flash emissions of 145 lb/bbl would require that 55% of the condensate flashed when reduced in pressure from 200 psig. This is not possible at this separator pressure. Since the other measured data for the vented gas (molecular weight of 36.6 and VOC fraction of 0.65) are reasonable, the error is most likely due to the low condensate production rate of 2 bbl/day used in the calculations. Rejecting this data point and recalculating the average VOC flash emissions from the remaining 19 tank batteries would give a factor of 17.8 lb/bbl, 53% of 33.3 lb/bbl.
- C. Throughput was not accurately determined, because the researchers did not follow their experimental design. Section B1 (Experimental Design), states "VOC emission rates will be measured by sampling the tank vent gas for compositional analysis and measuring the vent gas flow rate. Measurements of separator gas vented to the atmosphere will also be made. The concentration of each C1-C6 gas component in the sample, plus benzene, toluene, ethyl benzene, xylene (BTEX) and other C6+ VOC will be multiplied by the flow rate (averaged over 24-hours) to produce measurements of mass emission rates for each of the reported gas constituents and other C6+ VOC in units of pounds per hour. The mass emission rates will then be divided by the number of barrels produced during the 24-hour flow measurement period to produce emission factors in units of pounds per barrel. Critical measurements for this approach include the following:
 - Vent gas composition;
 - Vent gas flow rate; and
 - Oil or condensate production rate"

On the same page, when discussing selection of well sites to be tested, one of the stated criteria is that "The oil or condensate production rate is at least 2 barrels per day."

^Z The comments in this section are taken in large part from various comments submitted by Dr. Ed Ireland, Executive Director of the Barnett Shale Energy Education Council (BSEEC) to the Texas Commission on Environmental Quality (TCEQ) regarding various regulatory proceedings.

Lastly, Section B5 (Quality Control) states “The greatest source of uncertainty in the calculated emission factors is likely to be the estimation of oil or condensate produced over the sampling period. The accuracy of the emission factors derived from these tests will be limited to how accurately the production volumes can be determined during the sampling episode. While such production information is readily available on a monthly or annual basis from the Texas Railroad Commission, accurate production data over a 24-hour period is generally not available (emphasis added), and will have to be estimated from reading the tank level gauges (if present), manually gauging the tank level, or from production meters at the site if available. The specific methods and instruments used to estimate daily throughput will be recorded in the field sampling log; however, the sensitivities of these devices to oil or condensate throughput over 24-hours is unknown.”

1. Obtaining data from a well site that is producing only 2 barrels of condensate per day is very inaccurate when the goal is to calculate VOC emissions based on a 24-hr test period. Using emissions data based on this low amount of production lends itself to large sampling errors that can result in large variability in reported numbers (which is exactly what occurred). In addition, page 1 of Section B2 (Sampling and Measurement Methods), states that “The liquid production rates will be determined during the test period either by reading the level gage on the tanks (if present at the site), or by manually gauging the tanks. The manual tank readings will be adjusted to account for any unloading of the tanks into tank trucks during the test.”

The smallest capacity storage tank found in the report was 300 barrels. Even if one assumes a tank height of 20 feet (most likely the height would be 12 feet), the storage capacity of the tank would be around 15 bbl per foot. To gauge a 24-hr production rate of 2 barrels would mean taking two measurements to obtain a difference of about 1 ½ inches. For a tank height of 12 feet, measurement of a difference of 1 inch would be necessary. In addition, all of the sites had at least two tanks. Therefore, to measure 2 barrels of production would take two measurements to obtain a difference of 1/2 to 3/4 of an inch. It is easy to see that this technique would lead to large errors in assumed condensate production rate, and in fact, it appears that the researchers abandoned this concept at some point (see Item 2).

2. Our greatest concern is with the methodology used to estimate condensate production rates for the 24-hr test periods. Evidently, the researchers rightly determined that an accurate measurement of condensate production during the test periods from tank gauging was not feasible based on the concerns described above. It appears that, in place of measured condensate production, the researchers substituted 2005 daily average condensate production numbers for each tested site obtained from the RRC database (footnote “f” for Table 3-3 on page 3-4 “Daily average condensate production for 2005 from www.rrc.state.tx.us/interactive_data.html”). Using daily average condensate production numbers from a historical database, for which only monthly and yearly totals are reported, to calculate a VOC emissions factor from actual 24-hr test data for a specific tank battery can introduce large errors in the calculation of the flash VOC emissions factor as evidenced by the results from tank battery #17.

- D. Excluding tank batteries with a throughput of 2 bbl/day or less would give average VOC flash emissions of 14.9 lb/bbl. This is more in line with the results from the CDPHE study (cited in Section 1.2 of the report), which gave a range of 10.0 to 13.7 lb/bbl for different condensate producing regions, and with the simulation results discussed below

16.6.2. Variability of Flashing Emissions

A database that is more representative of nationwide emission rates from production field tanks than the data in the TERC study is available from the Geographical Database Option of the E&P TANK^{AA} program. For the 103 geographic sites across the U.S. for which E&P TANK results were tabulated in the Geographical Database Option, the average emission rate for condensate tanks (if condensate is defined as API gravity of 40 degrees or greater) is 11.4 lb/bbl and for crude oil tanks 1.1 lb/bbl. But, even with this larger sample, the variability in emissions per throughput barrel is large.

Under d. NSPS for Storage Vessels on page 52763 of the preamble, EPA correctly states “Flash losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing dissolved gases and a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the greater the flash emissions will occur in the storage stage. Temperature of the liquid also influences the amount of flash emissions. The amount of liquid entering the tank during a given time, commonly known as throughput, also affects the emissions rate, with higher throughput tanks having higher annual emissions, given that other parameters are the same.” However, EPA did not mention the other very important parameter, the volatility of the liquid, which can be indicated by API gravity but is more accurately a function of the composition of the high pressure separator liquid.

Flashing emissions determined using the E&P TANK low pressure oil option with a pressurized liquid sample are summarized in Table 16-1 for 7 sites in Texas and Louisiana. This table shows that, among sites with the same throughput, VOC emissions vary by three orders of magnitude (from 0.072 lb/bbl to 20.72 lb/bbl). This clearly establishes that throughput correlates very poorly to emissions.

Table 16-1 Variability of Flashing Emissions for Constant Throughput

Location	API Gravity	Throughput (bbl/day)	Pressure (psi)	Temperature (°F)	GOR	VOC Emissions (lb/bbl)
Robertson Co. TX	36	1	42	60	22.1	3.504
Shelby Co. TX	53	1	40	75	3.5	0.072

^{AA} American Petroleum Institute, “Production Tank Emissions Model - A Program For Estimating Emissions From Hydrocarbon Production Tanks - E&P TANK VERSION 2.0,” API Publication 4697.

Panola Co. TX	45	1	76	90	14.5	1.224
Claiborne Parish, LA	62	1	160	75	113.4	16.584
La Salle Parish, LA	32	1	47	114	0.5	0.528
Upsher Co. TX	56	1	230	60	203.9	20.760
Rusk Co. TX	47	1	108	98	13.2	2.664
Average	49	1	141.5	81.5	71.3	6.237

16.6.3. Specify an Applicability Threshold for Storage Tanks Based on Estimated Emissions

Given the variability of emissions as a function of site-specific conditions, we request that the rule specify an emissions threshold for storage tanks, and allow facilities to perform emissions estimates to determine whether a given storage tank is subject to the control requirements of the rule. As indicated by both EPA^{BB} and TCEQ^{CC}, appropriate methods of estimating flashing emissions include process simulation software and E&P TANK.

16.6.4. Allow Use of Default Emission Rates as a Function of Throughput and Separator Pressure

As an alternative to a site-specific estimate of flashing emissions, the rule should allow an estimate of flashing emissions to be obtained from a table that accounts for both throughput and separator pressure.

Figure 16-1 shows a graph of flashing emissions (in lb/bbl) as a function of separator pressure (in psi). This graph shows emissions estimated from three simulation methods. The results labeled "API Flash Factor" were obtained using ProMax^{DD} (includes two very volatile high API gravity condensates), the results labeled "TX & LA sites" were obtained using E&P TANK, and the results labeled "Anadarko well" were obtained using HYSYS^{EE}. For comparison, the TERC study average (33.3 lb/bbl) and the average of the E&P TANK Geographical Database Option with simulated results for 103 wells nationwide (11.4 lb/bbl) are also shown.

The TERC estimate is greater than the simulation results for any level of pressure, which

^{BB} STAPPA/ALAPCO/EPA, "Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations," Emission Inventory Improvement Program, Volume II: Chapter 10, September 1999.

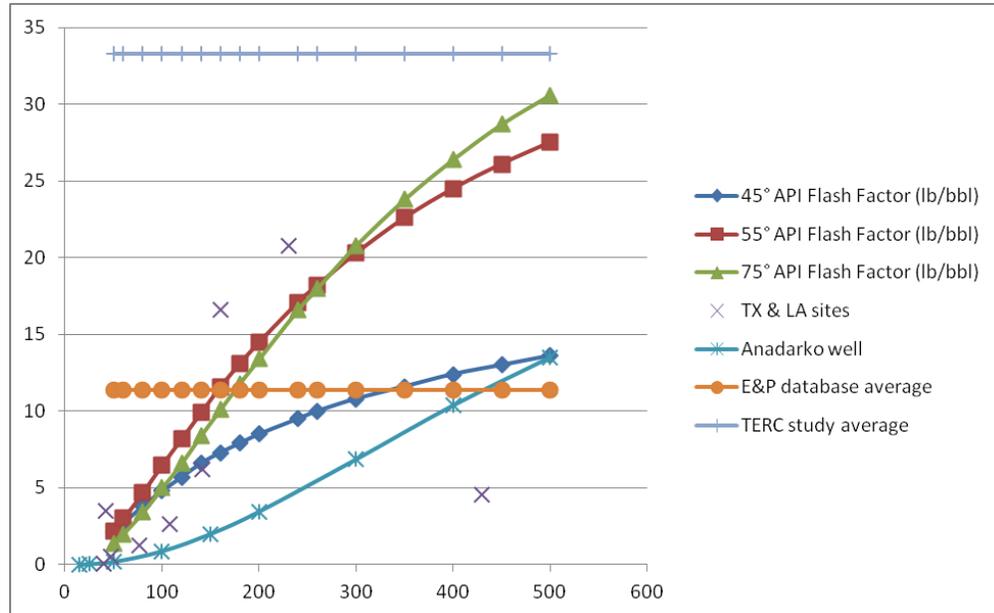
^{CC} Texas Commission on Environmental Quality, Air Permits Division, "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites," Air Permit Reference Guide APDG 5942, v2, September 2009.

^{DD} ProMax, Bryan Research & Engineering, Inc.

^{EE} AspenTech HYSYS 2006.5, Aspen Technology, Inc.

further suggests that it is not a credible value. However, as noted previously, a value of 14.9 lb/bbl is obtained from the TERC study when the most problematic data are removed from the data set. This value appears to be much more in line with simulation results using site-specific data. Also, the average value of 11.4 lb/bbl from the E&P TANK database falls reasonably within the simulation results. But the evident variability as a function of pressure shows that a simple average is not an appropriate indicator of flashing emissions.

Figure 16-1 Emissions (lb/bbl) vs. Separator Pressure (psi)



A throughput-based factor for estimating flashing emissions should be expressed as a function of pressure drop, rather than applying a simple average value as a function of throughput. This could be done by means of a lookup table.

The results of the ProMax simulations for the volatile condensates graphed in Figure 16-1 are tabulated in Table 16-2, along with results from a 38° API Gravity crude oil, showing the relationship between emissions, throughput, and separator pressure at multiple levels of API Gravity. In the simulations, the last separator temperature was set at 60°F, which is conservative since a higher temperature (which is typical for most sites with a heater-treater) lowers the amount of VOC flashed at the storage tank. Table 16-2 shows that emissions are highly influenced by pressure and, to a lesser extent, by API Gravity.

It is evident from Table 16-2 that an applicability threshold based on throughput should also account for separator pressure.

Table 16-2 VOC Flash Factors vs. Separator Pressure

Separator Pressure (psig)	38° API Crude Oil Flash Factor (lb/bbl)	45° API Condensate Flash Factor (lb/bbl)	55° API Condensate Flash Factor (lb/bbl)	75° API Condensate Flash Factor (lb/bbl)
10	0.2	0.2	0.1	0.1
20	0.5	0.5	0.4	0.3
30	0.9	1.0	0.9	0.6
40	1.3	1.6	1.5	0.9
50	1.7	2.1	2.2	1.4
60	2.1	2.7	3.0	2.0
80	2.8	3.8	4.7	3.4
100	3.4	4.8	6.5	5.0
120	4.0	5.7	8.2	6.6
140	4.4	6.6	9.9	8.4
160	4.8	7.3	11.6	10.1
180	5.2	7.9	13.1	11.8
200	5.5	8.5	14.5	13.4
240	6.1	9.5	17.1	16.6
260	6.3	10.0	18.2	18.0
300	6.7	10.8	20.3	20.8
350	7.2	11.6	22.6	23.8
400	7.6	12.4	24.5	26.4
450	7.9	13.0	26.1	28.7
500	8.3	13.6	27.5	30.6

16.6.5. Basis for Determining Throughput

Under §60.5410(e)(5)(i), EPA requires "You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications." Flow of condensate from a production separator to a storage vessel is intermittent and short duration. Every flow meter has a "latency period" that provides unreliable data for some period of time after flow begins. This unreliable period of time can range from a few seconds to several minutes depending on the technology. The "short duration" part of the equation is compounded by the latency period. It is frequent for a common technology like a turbine meter to over-range (i.e., spin faster than the magnetic revolution counter can count) for several seconds when it first opens in dump service. Often, by the time it has slowed to begin reporting reasonable values, the dump is beginning to close. It is common for either a turbine meter or a magnetic meter in dump service to report values that are 5-10 times higher than sales volumes that are eventually reported to accounting systems. There is no technology that will allow a 1 bbl/day condensate stream (or a 20 bbl/day oil stream for that matter) to accurately record flow volume into a storage

tank. API strongly recommends that the preferred method of quantifying liquid hydrocarbons throughput in the regulation be changed to “based on Lease Automatic Custody Transfer (LACT) meter, haul records (run tickets), sales tickets, or other sales documentation to show the amount transferred to a truck or liquids pipeline.” See Attachment H for background on technical issues pertaining to metering.

16.6.6. Variability of Cost Effectiveness

Using EPA's estimated annual cost for controls of \$18,983 and 95% control effectiveness, the cost effectiveness of controls for the sites shown in Table 16-1 is shown in Table 16-3. Table 16-3 shows that, when emissions are determined for a throughput of 1 bbl/day of condensate on a site-specific basis, the cost of controls varies from about \$5,300 to over \$1.5 million per ton. These costs are much higher than EPA's estimate of \$3,228/ton given in EPA's background technical support document (TSD) Table 7-10, because these costs are based on site-specific emission estimates rather than on a flawed study purporting to determine an average emissions rate as a function of throughput, which itself is an inaccurate indicator of emissions.

Table 16-3 Cost Effectiveness of Controls Using the TSD Cost Analysis.

Location	API Gravity	Throughput (bbl/day)	Pressure (psi)	Temperature (°F)	VOC Emissions (ton/ yr)	Emission Reductions (ton/ yr)	Annual Cost (\$/yr)	Cost Effectiveness (\$/ton)
Robertson Co. TX	36	1	42	60	0.6399	0.6079	\$18,983	\$ 31,226
Shelby Co. TX	53	1	40	75	0.0131	0.0124	\$18,983	\$1,519,667
Panola Co. TX	45	1	76	90	0.2235	0.2123	\$18,983	\$ 89,392
Claiborne Parish, LA	62	1	160	75	3.0287	2.8773	\$18,983	\$ 6,598
La Salle Parish, LA	32	1	47	114	0.0964	0.0916	\$18,983	\$ 207,227
Upsher Co. TX	56	1	230	60	3.7913	3.6017	\$18,983	\$ 5,271
Rusk Co. TX	47	1	108	98	0.4865	0.4622	\$18,983	\$ 41,072
Average	49	1	141.5	81.5	1.1390	1.0821	\$18,983	\$ 17,543

16.6.7. Corrected Cost Analysis

As noted above, the TSD used an annual cost of \$18,983 for controlling a tank. This cost, however, is inconsistent with the EPA Air Pollution Control Cost Manual^{FF} (EPA Cost Manual), which addresses enclosed combustors in Section 3.2. Using the method prescribed in the EPA Cost Manual, the annual cost of controls is \$55,207, as detailed below. This cost

^{FF} U.S. Environmental Protection Agency, “EPA Air Pollution Control Cost Manual,” EPA/452/B-02-001, Sixth Edition, January 2002. <http://www.epa.gov/ttn/catc/dir1/cs3-2ch1.pdf>

is conservative in that it includes no costs for data management required by the proposed rule, and it does not adjust for inflation since calendar year 2000.

Table 16-4 Capital Cost for Enclosed Combustor

<u>Item</u>			<u>Cost</u>
Direct Costs			
Purchased equipment costs			
	Combustor		14,102
	Auxiliary equipment (includes knock-out drum and piping)		828
	Sum = A		14,929
	Instrumentation =	0.10 A	1,493
	Sales taxes =	0.03 A	448
	Freight =	0.05 A	746
	Purchased equipment cost = B		17,617
Direct installation costs			
	Foundation & supports =	0.12 B	2,114
	Handling & erection =	0.40 B	7,047
	Electrical =	0.01 B	176
	Piping =	0.02 B	352
	Insulation =	0.01 B	176
	Painting =	0.01 B	176
	Direct installation cost	0.57 B	10,042
	Site preparation		0
	Facilities and buildings		0
	Total direct cost		27,658
Indirect Costs (installation)			
	Engineering	0.10 B	1,762
	Construction & field expenses	0.10 B	1,762
	Contractor fees	0.10 B	1,762
	Start-up	0.01 B	176
	Performance test	0.01 B	176
	Contingencies	0.03 B	529
	Total indirect cost	0.35 B	6,166
	Total Capital Cost = C		33,824
Annual Cost for Enclosed Combustor			
<u>Item</u>			<u>Cost</u>
Direct Annual Costs, DC			
	Operating Labor	630 hr/yr	
			<u>hourly cost</u>
			\$ 15.64
	Supervisor = 0.15(operating labor)		9,853
	Operating materials		1,478
			0
	Maintenance labor	547.5 hr/yr	\$ 17.21
	Maintenance material = maintenance labor		9,422
	Electricity		9,422
			0
	Purge gas \$ 3.03 /Msfc	0 Msfc/yr	0
	Pilot gas \$ 3.03 /Msfc	613.2 Msfc/yr	1,858

Steam	\$ 4.65 /1000 lb	0 1000 lb/yr	0
Total direct cost			32,034
Indirect Annual Costs, IC			
Overhead	0.6 (labor + matl)		18,106
Administrative costs	0.02 C		676
Property tax	0.01 C		338
Insurance	0.01 C		338
Capital recovery = CRF(total capital cost)			3,714
Total indirect cost			23,173
Total Annual Cost			55,207

Table 16-5 presents a cost effectiveness analysis using the annual cost of \$55,207 determined from the EPA Cost Manual, and a control effectiveness of 95%.

Table 16-5 Cost Effectiveness of Controls Based on the EPA Cost Manual.

Uncontrolled Emissions (tons/yr)	Emission Reductions (tons/yr)	Annual Cost (\$/yr)	Cost Effectiveness (\$/ton)
3	2.85	\$55,207	\$19,371
6	5.70	\$55,207	\$ 9,685
8	7.60	\$55,207	\$ 7,264
10	9.50	\$55,207	\$ 5,811
11	10.45	\$55,207	\$ 5,283
12	11.40	\$55,207	\$ 4,843
15	14.25	\$55,207	\$ 3,874
20	19.00	\$55,207	\$ 2,906

16.6.8. Requested Emissions Threshold

EPA concluded in the TSD that a cost of \$5,300 per ton was not cost effective. On this basis, Table 16-5 shows that a threshold of 11 tpy would not be cost effective, but a threshold of 12 tpy would be cost effective. API therefore requests a level of 12 tpy of VOC emissions as the threshold above which controls are required for a storage vessel under NSPS OOOO.

EPA proposed throughput thresholds pegged to 6 tpy of emissions in the storage tank provisions of §60.5395(a), as well as a 10 tpy emissions threshold in the definition of a storage vessel at §60.5430. These thresholds do not determine whether or not a given structure is a storage vessel, but rather they are criteria for determining whether a given storage vessel is subject to the control requirements of the rule. As such, the more appropriate location for them in the rule is at §60.5395, rather than in the definitions. API therefore requests that EPA move the emissions threshold from the storage vessel definition at §60.5430 to the storage vessel standard at §60.5395, and specify a threshold of 12 tpy.

16.6.9. Look-up Table Alternative

As we noted above, the regulations should specify that the owner or operator may estimate emissions to determine whether a given storage vessel would exceed the 12 tpy threshold, using E&P TANK or other process simulation software to account for flashing emissions. The rule should also include a look-up table as an alternative approach to determining applicability.

Despite EPA’s recognition of severable variables affecting the rate of VOC flash emissions, the agency chose a single VOC flash emissions factor of 33 lb/bbl for condensate and 1.6 lb/bbl for crude oil. Our previous comments demonstrate that the emission factors for condensate are based on faulty test data and data analysis, as well as the faulty premise that flashing emissions can be reasonably predicted as a simple function of throughput.

We agree that a throughput exemption threshold is convenient for operators in many situations; however, a “one-size-fits-all” throughput number is not appropriate due to the many variables that can affect emissions. Of those variables, last separator pressure and throughput are the most important. We therefore suggest a look-up table that is a function of these two variables as an alternative to estimating emissions to evaluate the applicability threshold.

The VOC flash factors from Table 16-2 may be converted to throughput thresholds corresponding to an emissions threshold of 12 tpy as follows:

$$Q = 12.00 \text{ tpy} * 2,000 \text{ lb/ton} * 1/365 \text{ d/yr} * 1/FF = 65.75/FF$$

where:

Q is the throughput, in barrels per day, and

FF is the flash factor, in pounds per barrel.

Using this approach, the flash factors from Table 16-2 have been converted to an applicability look-up table in Table 16-6. The flash factors given for condensate in Table 16-6 are based on the worst case at each level of separator pressure from the condensate cases given in Table 16-2. The flash factors given for crude oil in Table 16-6 are based on the 38° API Gravity crude oil from Table 16-2. In that 38° API Gravity is a very light crude oil, it is expected that these factors are conservative (*i.e.*, likely to overestimate VOC emissions for heavier crude oils). We request that EPA include this look-up table in NSPS OOOO as an alternative to estimating emissions to determine applicability.

**Table 16-6 Throughput Exemption Thresholds vs. Separator Pressure.
(corresponding to 12 tpy VOC emissions per tank)**

Separator Pressure (psig)	Crude Oil Throughput Threshold (bbl/day)	Condensate Throughput Threshold (bbl/day)
10	330	330
20	130	130

30	73	66
40	50	41
50	39	30
60	31	22
80	23	14
100	19	10.0
120	16	8.0
140	15	6.6
160	14	5.7
180	13	5.0
200	12	4.5
240	11	3.8
260	10	3.6
300	10	3.2
350	9.0	2.8
400	8.7	2.5
450	8.3	2.3
500	8.0	2.1

16.6.10. Allowance for Production Decline.

In that oil field production declines over time, storage vessels that initially emit more than 12 tpy may eventually fall below 12 tpy of emissions. EPA should specify that controls are no longer required after a storage vessel no longer emits more than 8 TPY similar to the WYDEQ Best Available Control Technology (BACT) Policy^{GG}. EPA has allowed boilers that are derated below 100 TPY to no longer be subject to NSPS Subparts D, Da, Db, and Dc. Attachment I contains applicability determinations given by EPA allowing boilers to no longer be subject to NSPS D, Da, Db, and Dc. Furthermore, the cost effectiveness analysis above shows that controls at 8 tpy are not cost effective.

16.7. Compliance Schedule for New Production [NSPS OOOO]

The rule should allow time to evaluate the throughput, pressure, and emissions before the control must be installed and then time to install the control. For instance WYDEQ bases control on the first 30 days of production multiplied by a decline factor, and then control must be installed 60 days later.^{HH} WYDEQ allows the use of the first 30 days production multiplied by a decline factor for determining applicability of the rule because it is very difficult to predict the actual production for a well before the well is producing. This method gives operators a chance to estimate what the annual

^{GG} Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

^{HH} Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010, <http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>

production and emissions could be and then allows time to install a control if the emissions were to exceed the specified threshold.

16.8. Compliance Requirements [NSPS OOOO]

Suggested Rule Text:

§60.5365

If you are the owner or operator of a site prior to the point of custody transfer at which is located one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. Paragraphs §60.5365(a)-(e) apply only to affected facilities in VOC service. ~~For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.~~

* * * * *

- (e) A storage vessel affected facility, which is defined as a single storage vessel storing condensate or crude oil and located prior to the point of custody transfer.

§60.5395

You must comply with the standards in paragraphs (a) through (eg) of this section for each storage vessel affected facility.

- (a) You must comply with the standards for storage vessels storing condensate or crude oil specified in ~~40 CFR part 63, subpart HH, §63.766(b) and (c) paragraph (b) of this section,~~ except as specified in paragraph (bd) of this section. ~~Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section.~~ Storage vessels with annual average VOC emissions less than 12 tons per year, estimated according to paragraph (c)(3) of this section, are exempt. A storage vessel that has been subject to this standard becomes exempt when the uncontrolled emissions of VOC drop below an annual average of 8 tons per year.

~~(1) The annual average condensate throughput is less than 1.5 barrel per day per storage vessel.~~

~~(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel.~~

- (b) Within 90 days of the first date of production the owner or operator shall equip the affected storage vessel closed vent system and control device meeting the following specifications:

(1) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions.

(2) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.

(c) The annual average daily throughput and pressure and the annual emissions for a new well shall be determined as follows:

(1) First 30 days of throughput after the first date of production divided by 30 times the average decline factor for the reservoir based on Lease Automatic Custody Transfer (LACT) meter, haul records (run tickets), sales tickets, or other sales documentation to show the amount transferred to a truck or liquids pipeline.

(2) Pressure of separator prior to the tank averaged over the first 30 days after the first date of production.

(3) Calculated using either methods (i) or (ii) using the average annual throughput calculated under (c)(1) and the average pressure calculated under (c)(2) for demonstrating compliance with (a)(1):

(i) E&P TANK or an appropriate flashing model.

(ii) Interpolating from the table below:

<u>Separator Pressure (psig)</u>	<u>Crude Oil Throughput Threshold (bbl/day)</u>	<u>Condensate Throughput Threshold (bbl/day)</u>
<u>10</u>	<u>330</u>	<u>330</u>
<u>20</u>	<u>130</u>	<u>130</u>
<u>30</u>	<u>73</u>	<u>66</u>
<u>40</u>	<u>50</u>	<u>41</u>
<u>50</u>	<u>39</u>	<u>30</u>
<u>60</u>	<u>31</u>	<u>22</u>
<u>80</u>	<u>23</u>	<u>14</u>
<u>100</u>	<u>19</u>	<u>10.0</u>
<u>120</u>	<u>16</u>	<u>8.0</u>
<u>140</u>	<u>15</u>	<u>6.6</u>
<u>160</u>	<u>14</u>	<u>5.7</u>
<u>180</u>	<u>13</u>	<u>5.0</u>
<u>200</u>	<u>12</u>	<u>4.5</u>
<u>240</u>	<u>11</u>	<u>3.8</u>
<u>260</u>	<u>10</u>	<u>3.6</u>
<u>300</u>	<u>10</u>	<u>3.2</u>
<u>350</u>	<u>9.0</u>	<u>2.8</u>
<u>400</u>	<u>8.7</u>	<u>2.5</u>
<u>450</u>	<u>8.3</u>	<u>2.3</u>
<u>500</u>	<u>8.0</u>	<u>2.1</u>

- (bd) This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 63, subpart HH, §63.766(b)(1) or (2).
- (ee) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by §60.5410.
- (df) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by §60.5415.
- (eg) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

§60.5410

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in §60.5420(b).

* * * * *

- (e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1) through (e)(7) of this section.
 - (1) You have equipped the storage vessel with a closed vent system ~~that meets the requirements of §63.771(e) connected to a~~ and a control device that meets the conditions specified in ~~§63.771(d)~~ §60.5395(b).
 - ~~(2) You have conducted an initial performance test as required in §63.772(e) within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in §63.772(f).~~
 - ~~(3) You have conducted the initial inspections required in §63.773(e)~~
 - ~~(4) You have installed and operated continuous parameter monitoring systems in accordance with §63.773(d)~~
 - ~~(5) If you are exempt from the standards of §60.5395 according to §60.5395(a)(1) or (a)(2), you have determined the condensate or crude oil throughput, pressure, and emissions according to §60.5395(c), as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank.

 - ~~(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications.~~
 - ~~(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput.~~~~

(63) You have submitted the information in paragraphs (e)(1) through (e)(5) of this section in the initial annual report for your storage vessel affected facility as required in §60.5420(b).

§60.5415

* * * * *

(e) ~~For each storage vessel affected facility, continuous compliance is demonstrated according to 40 CFR part 63, subpart HH, §63.772(f).~~ The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.5395(b) shall meet the requirements of either (1) or (2) below.

(1) Develop and maintain an operating plan containing the information listed below and operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (2)(i) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) A control device that has been certified by the manufacture with a performance test to demonstrate the device meets the requirements of §60.5395(b) and parameters limits needed to meet the requirements of §60.5395(b) to measure. Monitor the parameters of the control device to demonstrate the control device is operating within the parameter limits specified by the manufacture.

§60.5420

* * * * *

(b) **Reporting requirements.** You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year

after the date of publication of the final rule in the Federal Register, whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

* * * * *

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

- (i) If required to reduce emissions by complying with paragraph §60.5395(ab), ~~the records specified in 40 CFR part 63, subpart §63.774(b)(2) through (b)(8) the API number of the location of the tank and date of installation.~~
- (ii) ~~If exempt from §60.5395 in accordance with §60.5395(a), the API number of the location of the exempt tank and date of installation. Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in §60.5395(a)(1) or (a)(2).~~

(c) **Recordkeeping requirements.** You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

* * * * *

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

- (i) If required to reduce emissions by complying with ~~§63.766~~ §60.5395(b), maintain the following records ~~specified in §63.774(b)(2) through (8) of this chapter.:~~

(A) A copy of the operating plan if using §60.5415(e)(1).

(B) A copy of manufacturer certification if using §60.5415(e)(2)

(C) A record of the measured values of the parameters monitored.

- (ii) Records of the determination of the throughput, pressure, and emissions using the methods in §60.5395(c) to demonstrate emissions are below 12 TPY. ~~that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under §60.5395(a)(1) and (a)(2).~~

§60.5430

Condensate means a ~~hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in §60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate.~~ natural gas liquid recovered from

associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60 degrees Fahrenheit.

First Date of Production means the date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production from initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.

Alternative Rule Text (if EPA insists on citing to Subpart HH):

The requirements in NSPS OOOO for storage tank control devices cite the performance test requirements specified in §63.772(e) of NESHAP HH, which include a provision for the performance test to be conducted by the manufacturer as specified in §63.772(h). While the intent appears to allow the manufacturer’s certification specified in §63.772(h) for NSPS OOOO, it would be helpful if NSPS OOOO were to explicitly say so. API requests that EPA clarify this intent by editing §60.5410 to read as follows:

§60.5410

(e)(2) You have conducted an initial performance test as required in §63.772(e) of this chapter, or you have a copy of the performance test results for a performance test conducted by the manufacturer as specified in §63.772(h), within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in §63.772(f).

16.9. Capacity and Vapor Pressure [NSPS OOOO]

Every EPA regulation with provisions for storage vessels has capacity and vapor pressure thresholds below which the specified control measures are not required – even rules for the storage of gasoline and benzene. It is certainly unreasonable, then, to not have capacity and vapor pressure cutoffs for vessels storing crude oil and condensate. The cutoffs in NSPS Subpart Kb have already been determined by EPA as appropriate for storage vessels, and thus would seem appropriate for NSPS OOOO as well. However, we recognize that the oil production sector has the unique situation of potential for flash emissions, and thus it would be reasonable to remove the minimum capacity threshold in Subpart Kb when applying these thresholds to Subpart OOOO. The Subpart Kb cutoffs are presented in Table 16-7, with suggested adjustment for Subpart OOOO.

Table 16-7 Capacity and Vapor Pressure Cutoffs

Subpart Kb	Subpart OOOO
Controls are not required if a storage vessel has:	Controls are not required if a storage vessel has:
a capacity of less than 75 m ³ (472 bbl) regardless of the vapor pressure;	a capacity of less than 75 m ³ (472 bbl) And true vapor pressure less than 11.1 psia

or		
a capacity of less than 151 m ³ (950 bbl)	and	true vapor pressure less than 4.0 psia;
or		
a capacity greater than 151 m ³ (950 bbl)	and	true vapor pressure less than 0.75 psia;

or		
a capacity of less than 151 m ³ (950 bbl)	and	true vapor pressure less than 4.0 psia;
or		
a capacity greater than 151 m ³ (950 bbl)	and	true vapor pressure less than 0.75 psia;

16.10. Infrequent Use [OOOO & HH]

EPA’s capacity and vapor pressure thresholds are based on emissions that would be expected if these tanks were in continuous operation. However, tanks such as blowdown tanks, emergency tanks, and dehydrator drip tanks are used only infrequently. EPA should specify a threshold for storage vessels in infrequent use, and specify a work practice for such tanks. There is precedent for this in the Gasoline Distribution area source rule. EPA must allow for open-top blow down tanks. A well cannot be blown down to a closed top tank. The conventional set up is to route the gas associated with a blow down to the produced water tank to allow for entrained liquid to be contained during the event. Knocking out this entrained liquid will be a critical step in flaring this stream as well. However, the tanks are only rated to around 10-12 oz with thief hatch seals set at approximately 6 oz of pressure to protect tank integrity. The majority of tanks in the field are not designed to take the back pressures anticipated by the piping changes. These tanks are typically “atmospheric” tanks/vessels designed to operate at pressures not exceeding 15 psig (per mechanical design codes defined by the American Society of Mechanical Engineers). The relief valves and seals are designed and operate accordingly. Piping system for the combustion device will provide too much back pressure during a blow down event and the safety devices will vent the tanks as they should.

The EPA needs to recognize that implementation of this requirement is far more complicated than connecting up existing tanks to combustors. The entire tank system would need to be evaluated and possibly replaced with a “code stamped” pressure vessel/tank and appropriately sized and designed safety valves, hatches, and gas piping. Accordingly, the EPA needs to fully recognize the associated costs which are substantially more. Furthermore, infrequently used tanks such as blowdown tanks, emergency tanks, and dehydrator drip tanks were not considered in EPA’s cost effectiveness analysis.

16.11. Flare Pilot Flame [OOOO & HH]

The requirement in §60.18(c)(2) and §63.11(b)(5) for a flare to be operated “with a flame present at all times,” referenced by NSPS OOOO [§60.5401(f)] and NESHAP HH [§63.771(d)(1)(iii)] respectively, is not appropriate in light of current technology. This issue is discussed in more detail in Section 9.1 of the general comments.

16.12. Performance Test Methods [OOOO & HH]

See Section 8.6 of the general comments for API’s recommendations with respect to performance tests.

16.13. MACT-Level Requirements for NSPS

EPA has referenced the full MACT requirements in NESHAP HH for NSPS OOOO, rather than craft cost-effective requirements tailored for storage tanks with relatively low annual VOC emissions and generally located in remote areas. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for NSPS OOOO. This is illustrated in the cost discussion above, where annual costs determined from EPA's Cost Manual are shown to be nearly 3 times the cost that EPA presented in the TSD. Furthermore, NSPS OOOO applies to dispersed locations that do not have electricity or automation, and with limited remote transmitting unit (RTU) space. Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH, it is not appropriate to arbitrarily invoke requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for an NSPS regulation for the control of volatile organic compounds (VOCs). See Section 8.7 of these comments.

Examples of the inappropriateness of invoking MACT requirements for NSPS include but are not limited to:

- **§63.773(d) Control Device Monitoring requirements [Continuous Parameter Monitoring System (CPMS)].** EPA did not include the cost for installing, maintaining, and operating a CPMS. Most affected storage tanks will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work can not be performed by lease operators during normal inspection visits.
- **§63.772 Test Methods, Compliance Procedures, Compliance Demonstrations.** EPA should reference test methods specific to VOCs. Many of the methods reference HAPs or comparison of a performance test to a HAP emission limit. This causes confusion in understanding how to apply the requirements to a VOC standard. EPA should reference test methods, compliance procedures, and compliance demonstrations that are specific to VOCs and the type of control device being used to control VOCs.
- **§63.774(b)(2) through (8) Recordkeeping Requirements.** The proposed recordkeeping requirements result in more than 56 different records to be maintained for a single tank (see Attachment J). These overwhelming and burdensome recordkeeping requirements are unreasonable and unjustified.

16.14. Floating roof option [OOOO & HH]

Other regulations governing storage tanks allow floating roofs as an alternative to routing vapor to a control device. Consideration should be given to providing a floating roof control option under these rules. While floating roofs are not viable for tanks with the potential for flash emissions or for very small tanks, they may be suitable for larger production field tanks storing stabilized crude oil, and

thereby avoid roof fitting leak tightness requirements. API requests that EPA revise both NSPS OOOO and NESHAP HH to specify that a storage vessel storing a volatile organic liquid with a maximum true vapor pressure of less than 11.1 psia may be equipped with a floating roof, in lieu of routing vapors to a control device. We suggest that EPA specify the floating roof requirements in the same manner as in Table 1 of the Gasoline Distribution area source rule.ⁱⁱ

16.15. EPA's Estimate of the Number of Affected Storage Vessels

See FR page 52789, Preamble VIII.A. EPA predicts that a very small fraction of the production field tank population will be affected by this rulemaking. While we have not yet evaluated these numbers, we believe for the reasons stated below that the total cost impact of the rule will be dramatically greater than projected by EPA.

16.15.1.NESHAP HH

The proposed changes to the definition of an affected facility will likely cause some existing sites that were not previously major sources to become major sources, due to the expansion of emission points that EPA proposes to include in the major source determination. Tanks at these facilities would then become subject to NESHAP HH controls, but EPA does not appear to have taken these tanks into account when evaluating the impact of the proposed rule revisions.

16.15.2.NSPS OOOO

EPA apparently evaluated the existing well population, which is dominated by old wells that have declined to very low production rates (sometimes known as stripper or marginal wells), and assumed that the production rates of these stripper wells would be characteristic of new wells. On this basis, EPA assumed that very few new wells would have sufficient flow to trigger applicability for storage tanks under NSPS OOOO. This is a fundamentally flawed assumption, in that companies do not purposely drill low producing wells. New wells would not be drilled unless there was an expectation of flow significantly greater than EPA's proposed throughput thresholds, and thus virtually all new wells would likely trigger NSPS OOOO applicability for the associated storage tanks.

16.16. Permit Limits

Under the MACT rules, a facility can avoid major source status if it has federally enforceable permit conditions that preclude emitting above the major source threshold (i.e., synthetic minor status). Similarly, if EPA sets an emissions-based applicability threshold for tanks under NSPS OOOO, the rule should specify that legally effective PTE limits (such as those issued through state minor NSR permits) are one means that may be used to manage applicability of the rule. EPA has ample legal authority to define the applicability of an NSPS. Such an approach would be a reasonable exercise of that authority. In addition, such an approach would be consistent with similar approaches taken in prior NSPSs. For example, the NSPS for Bulk Gasoline Terminals applies to facilities with a throughput greater than 75,700 liters/day. The gasoline throughput of a facility "shall be the

ⁱⁱ 40 CFR Part 63 Subpart BBBBBB—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.” 40 C.F.R. § 60.501 (definition of “bulk gasoline terminal”).

17. PNEUMATIC CONTROLLERS

API supports the use of intermittent vent, electro-pneumatic, and low bleed pneumatic controllers where feasible, however, certain key language in the proposal is unclear with regard to applicability, is unnecessarily restrictive, and creates burdensome, and needless recordkeeping and reporting requirements.

API supports comments regarding pneumatic controllers provided to EPA by the Gas Processors Association (GPA). We are in agreement that the only regulated sources should be high bleed gas-driven pneumatic controllers. We would add that EPA should only regulate high bleed gas-driven controllers in VOC service as we argue numerous times throughout this comment document for affected facilities with natural gas emissions. As well, limiting regulation to controllers in VOC service would markedly reduce the recordkeeping and reporting burden in the proposal.

Before continuing review of our comments and suggested rule text changes API recommends that EPA reviewers read the pneumatic controller technical paper in Attachment K and Kimray, Inc.'s technical bulletin Y09201 “Pilot Bleed Rate” in Attachment L^{JJ}. Both of these papers are excellent references that clarify the terminology and technology of pneumatic controllers.

From our review of the preamble, proposal, TSD, and Natural Gas STAR documentation, EPA appears to have an inconsistent understanding of the design and operation of pneumatics. For example, in the preamble EPA incorrectly states: “(1) Continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure and gas is vented at a steady state rate; (2) actuating/intermittent devices (high or low-bleed) perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow...” indicating that both high and low bleed controllers can be either continuous or intermittent vent. However, in the proposed rule language and TSD, EPA correctly categorizes high and low bleed controllers as continuous bleed controllers only. The result of this inconsistency is an affected facility that effectively includes all pneumatic controllers when intermittent vent controllers are considered neither high nor low bleed, but rather no-bleed controllers that have no weak stream vent. As a result, intermittent vent controllers are not defined in the proposal, but should be exempted from this rulemaking. A fundamental and consistent understanding of pneumatic terminology, design, and operation is essential to providing an effective regulatory framework that works for both industry and EPA alike.

API provides suggested changes to proposed rule language in Attachment C that limits requirements to continuous bleed gas-driven controllers, clarifies both intent and compliance requirements, and simplifies the recordkeeping and reporting requirements. The underlying premise of our comments is that this rule needs to be clearly limited to “continuous bleed gas-driven pneumatic controllers,” but grouped as pneumatically controlled process unit affected facilities. Additionally, pneumatic controllers driven by compressed air, or other medium that does not contain VOC, cannot be affected facilities since there are no regulated emissions associated with them. In no other NSPS subpart do definitions of affected facilities include those with no regulated emissions. The following discussion explains in detail the issues and recommendations identified by API.

^{JJ} <http://kimray.com/LinkClick.aspx?fileticket=WvoYfx11%2f6E%3d&tabid=215&mid=811>

17.1. Problem with High-Bleed/Low-Bleed Classification

The proposed rule sets a threshold of 6 SCF/hr to classify continuous “high bleed” and “low bleed” controllers and EPA seeks to regulate both. There is no discussion in the proposed rule or in the TSD that explains how this threshold was derived. Instead, there is only a footnote on page 5-3 in the TSD that says this classification originated from a PG&E/GRI report in 1990, titled “Unaccounted for Gas Project Summary Volume” that EPA adopted for a 1993 report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. EPA has failed to include this 1990 PG&E report in the docket. API, via email to EPA staff, also requested background documentation addressing how the 6 scfh threshold was derived. No reply was received. Without needed documentation being made available, API is unable to review and comment on the validity of this threshold classification.

From the 1993 congressional report, this 6 scfh threshold carried forward into EPA's definition of a low bleed controller for the Natural Gas STAR (NGS) program. However, NGS was a voluntary program. The 6 scfh dividing line for low bleed/high bleed became an acceptable threshold by EPA declaration that wasn't subjected to the needed scrutiny required for rulemaking and regulatory compliance obligations. Using this threshold declared by EPA fiat since 1993 in a non-regulatory environment does not satisfactorily justify its use in rulemaking. Not being able to review the 1990 PG&E report, API has no way of knowing under what conditions bleed rates for continuous bleed controllers were determined to set this threshold.

EPA has set a performance standard without making available its own independent BSER technical review for continuous bleed pneumatic controllers. In addition to not having access to the 1990 PG&E report, the TSD data is incomplete, and does not include details of the data collected from their vendor surveys. API has asked for this data in emails to EPA staff, but did not receive a response to this request. With this data unavailable for review, API cannot conduct its own quality assurance analysis (QA) of the data and comment on the results.

Concurrent with an incomplete demonstration of BSER, without the needed background documentation in the docket, EPA has not “adequately demonstrated” that less than 6 scfh bleed rate is practically “achievable” as BDT for continuous bleed controllers as required by CAA §111(a)(1). The issues with BSER and BDT can be remedied by re-proposing these requirements with inclusion of the necessary background documentation placed in the docket.

Without the appropriate technical documentation available for stakeholder review and comment, API is not supportive of the 6 scfh threshold for continuous high bleed controllers. API believes the 6 scfh threshold is too low for defining the high bleed/low bleed boundary for continuous bleed pneumatic controllers. Only a few models advertised as continuous low bleed controllers operating at < 6 scfh are available in the marketplace. And those that advertise low bleed rates, base it on operating at a low supply gas pressure such as 20 psi or less though the devices are designed for and frequently operate at higher pressures. Guarantees of a constant low bleed rate of < 6 scfh are not reasonable as operating variables in the field dictate controller bleed rates. These variables can include dependence on a supply pressure required by the actuator that is higher than that advertised by a manufacturer for low bleed controller performance.

As pointed out in the technical paper in Attachment K, a 6 scfh dividing line between high bleed and low bleed will effectively mean most operators will choose between continuous high bleed and intermittent vent controllers that are no-bleed, which should be considered a desirable outcome. The reason for this is that most continuous bleed controllers will require a pilot orifice so small, that reliability of the controller will be an issue. Plugging of the orifice will be a major concern as will controller response time. Also, if the controller is part of a pneumatic system where the valve actuator requires a higher pressure to operate than the advertised supply pressure for low bleed rate performance, the "low bleed" controller operating at a lower pressure than required could very well result in sluggish end-device performance and increase the risk of liquid spills and uncontrolled gas releases. Since intermittent vent controllers have no continuous bleed rate, in most cases where feasible, this will be the choice for operators that do not want to be subject to the requirements for high bleed controllers and want to be exempt from the rule.

From the TSD, EPA recognizes there are intermittent vent pneumatic controllers that are no-bleed. EPA correctly refers to snap acting controllers as no-bleed, and acknowledges that intermittent vent rates are dependent on valve actuation volume and frequency which cannot be regulated. Hence, snap acting controllers appear to be exempt from the rule. However, as illustrated in the API technical paper in Attachment K and EPA's 1996 report "Methane Emissions from the Natural Gas Industry," Vol. 12^{KK}, throttling controllers can also be intermittent vent. Likewise, continuous bleed controllers can also be converted to intermittent vent no bleed controllers by replacing the pilot valve with a Mizer type no-bleed pilot. As with snap acting controllers, all other intermittent vent controllers should be exempt from the rule.

17.2. Definitions

The subject of pneumatic controllers is highly technical and has been the province of a very narrow subset of industry experts. Unfortunately, key terminology and definitions have never been standardized which adds complexity to this rulemaking. Consequently, one of the results of this problem has led to inadequate definitions in the proposal. For example, the proposed definition of pneumatic controller in Subpart OOOO is "Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature". A more appropriate definition would be "Pneumatic controller means an instrument that is able to sense the state of a process variable and send a pressure signal to an end device to affect a change in that process variable". With EPA's proposed definition, an incorrect conclusion can be made that the end-device such as a control valve that actually maintains the process condition or variable is being regulated instead of the controller. API is recommending language for definitions needing clarity which apply to pneumatic controllers and recommending definitions for additional terms not currently in the proposal.

17.2.1. Revised Definitions

For clarity API recommends EPA's proposed definitions for pneumatic controllers be revised to read as follows:

^{KK} U.S. Environmental Protection Agency, "Methane Emissions from the Natural Gas Industry – Volume 12: Pneumatic Devices," EPA/600/R-96-0801, June 1996.

§60.5430

Pneumatic controller means an ~~automated~~ instrument that is able to sense the state of a process variable and send a pressure signal to an end device to affect a change in that process variable.~~used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature.~~

Gas-driven pneumatic controller means a pneumatic controller that directs a signal to an end device using pressurized natural gas.~~powered by pressurized natural gas.~~

Non gas-driven pneumatic controller ~~device~~ means a pneumatic controller that directs a signal to an end device in a medium other than natural gas. The signal can include compressed air, electric power, or hydraulic power.~~means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~

Low-bleed pneumatic controller means a continuous bleed pneumatic controller which controls pressurized gas that has the ability to vent the weak stream to the atmosphere at a rate equal to or less than six standard cubic feet per hour.~~automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.~~

High-bleed pneumatic controller means a continuous bleed pneumatic controller which controls pressurized gas that has the ability to vent the weak stream to the atmosphere at a rate greater than six standard cubic feet per hour.~~automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.~~

The definition changes API proposes remove ambiguity, and help clarify the rule. These changes in definition are especially important to the rule text revisions API recommends in Attachment C. In particular, API's revisions add "weak stream" to the definitions of low and high bleed controllers. Weak stream is added as a new definition in the next section, but this is a critically important term to unambiguously distinguish which stream in a continuous bleed controller is being regulated. Our recommended rule text revisions are based on use of these definition revisions.

17.2.2. New Definitions

In addition to revising existing proposed definitions, API recommends five new definitions to help with rule clarity and recommendations to rule text. The list of terms API recommends to be defined are:

§60.5430

Continuous bleed pneumatic controller means a pneumatic controller that does not have a mechanical barrier between the pressure source and the end device and controls the signal to the end device by adjusting the magnitude of the flow rate of the bleed gas to the atmosphere (weak stream) through an adjustable port.

Intermittent vent pneumatic controller means a pneumatic controller that has an internal mechanical barrier between the source of gas pressure and the end device. In response to an input signal, these devices will shut the vent and open the mechanical barrier to send gas pressure to the end device. When the input signal has been satisfied it shuts the mechanical barrier and opens a vent to remove pressure from the end device.

Weak stream means the stream of gas that is vented when the end device is “at rest” in its idle position (e.g., when the end device is shut on a pressure-to-open system).

Pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate the flow, pressure, or temperature of gas and liquids located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, pressure regulators, pneumatic controllers, valve actuators, and valves.

Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, continuous bleed gas-driven pneumatic controllers, valve actuators, and valves.

Again, these new terms are important to the rule text changes API is recommending. The “continuous bleed pneumatic controller and “continuous bleed gas-driven pneumatically controlled process unit” are new terms vitally important to API’s recommendation for changes in §60.5365(d) for the affected facility discussed below in section 17.4. “Weak stream” requires definition because in the rule text revisions in Attachment C, API frequently recommends use of this term to clearly define which controller vent stream is being regulated. “Weak stream” is also used in suggested rule text changes for pneumatic controllers. As recommended previously, EPA may refer to the technical paper in Attachment K, for a more detailed discussion of the “weak stream” and “intermittent vent pneumatic controller”.

17.3. Inconsistent Terminology

Another problem with definitions and the proposal in general is inconsistent terminology when referring to pneumatic controllers. The terms “pneumatic device” and “pneumatic controller” are used interchangeably throughout the proposal. Examples are the definitions of “high bleed pneumatic devices” and “low bleed pneumatic controller”. API recommends that all instances of the

term "pneumatic device" be replaced with "pneumatic controller". Pneumatic device is a general nonspecific term, and even though it is meant to be synonymous with pneumatic controller, it could create uncertainty with regard to applicability.

17.4. Pneumatic Controller Affected Facility

From both the discussion of pneumatic controllers in Section 5.0 of the Technical Support Document (TSD) and the definitions provided in Subpart OOOO §60.5430 for high bleed and low bleed controllers, EPA clearly shows that the rulemaking was intended to apply to "continuous bleed" pneumatic controllers in natural gas service. From Section 5.1 of the TSD, EPA states: "Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in Section 5.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation." The continuously bleeding stream referred to both in the preceding quote from the TSD and in the proposed definitions for high and low bleed controllers is also known as the "weak stream". API agrees if pneumatic controllers are to be regulated, it is only the weak stream that should be regulated.

Additionally, pneumatic controllers are small, component level, and inexpensive pieces of equipment for which minor expenditures for routine maintenance, repair, or replacement (RMRR) may trigger a reconstruction determination. Consequently, the pneumatic controller affected facility definition needs to be redefined as a process unit to address the collection of all equipment used to pneumatically control an end device such as a valve using continuous bleed gas-driven pneumatic controllers in VOC service.

17.4.1. Include Continuous Bleed Only

As alluded to in this section's introduction, due to inaccuracies in the discussion of pneumatic controller design and operation in the preamble, and the nonspecific definition of a pneumatic controller affected facility in §60.5365(d), a high level of confusion exists over EPA's intention of what is meant by a "pneumatic controller affected facility". Snap acting and other intermittent vent controllers have no weak stream that continuously bleeds, and as EPA correctly points out in the TSD, the intermittent vent rate is dependent on the necessary cycling frequency of the controller. Consequently, a narrower, more specific definition of pneumatic controller affected facility that limits applicability to continuous bleed controllers is needed to clarify both EPA's intent and the type of controller being regulated.

17.4.2. Include Gas-Driven Only

In addition, the proposed rule includes all pneumatic controllers regardless of the medium used to drive the controller. As EPA correctly points out in the proposal, compressed air or "instrument air" or other inert gas is frequently used as the driver for pneumatic controllers. However, since neither air nor inert gas driven controllers produce regulated emissions, these controllers should not be affected facilities.

As in other NSPS Subparts for source categories, a method of documented applicability determination can be employed by operators. Subpart Kb for example, defines applicability

based on the design capacity of the tank and vapor pressure of the fluid being stored. Equivalently, one of the design criteria for pneumatic controllers at a site is the medium used to drive the controller. Since compressed air and inert gas drivers have no regulated emissions, a design to operate controllers without using a natural gas driver should exempt these controllers as affected facilities. As a result, in addition to narrowing the affected facility to continuous bleed controllers, the affected facility needs to be further limited to a natural gas-driven pneumatic controller in VOC service.

17.4.3. Modification/Reconstruction Must Not Apply to Individual Controllers

As discussed in Section 2.3, pneumatic controllers are an unprecedented small affected source. In fact, a pneumatic controller is not even a piece of operating equipment on its own, but only a component that sends a control signal to another piece of equipment. The concept of reconstruction was developed to trigger when "the Administrator will consider, on a case-by-case basis, technical and economic parameters in determining 'whether a substantial portion of a facility has been replaced'" (see 39 FR 36946). The types of affected facilities being considered in the 1970's when this concept was developed were large boilers, tanks, and waste incinerators. The "50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility" [§60.15(b)(1)] threshold for reconstruction did not consider affected facilities where the "entirely new facility" would cost just a few hundred to a few thousand dollars. In fact, pneumatic controllers would have been only one small component of an affected source being regulated until this rulemaking.

API believes that neither modification, reconstruction, nor the total replacement of a pneumatic controller should be subject to the provisions of NSPS OOOO. At most, only the installation of a new pneumatic controller on a newly constructed process unit should be regulated. API recommends that §60.5365(d) be revised to group all equipment used for gas-driven pneumatically controlled valves into a single "continuous bleed gas-driven pneumatically controlled process unit." This removes the individual pneumatic controller as an affected facility, and more appropriately treats it as a component of a process unit. If EPA refuses to group pneumatic controllers within a process unit, then EPA should explicitly exempt pneumatic controllers from having to undergo modification and reconstruction determinations as a result of RMRR.

To illustrate this point, consider the following example. It is determined that a single existing low bleed controller installed sometime before this rule was proposed, requires pilot replacement because of problems with plugging. With a larger orifice pilot, the bleed rate increases slightly. This change causes an insignificant increase in emissions, but is still a modification. This simple repair now has to be documented and reported in an annual report, even though it still meets the criteria for a low bleed controller. Repairs must also be evaluated for reconstruction, since it doesn't take much in the way of parts replacement to achieve the 50% threshold. Making this determination for frequently occurring simple repairs that do not require any advanced planning and contracting as is done for large facilities in other source categories cannot be done with any reliability or accuracy. Maintenance personnel are not equipped or trained to make this evaluation, and simple repairs could be delayed if a complete reconstruction analysis was performed for each

occurrence of repair.

When considering the relatively low emissions of a single pneumatic controller combined with the impractical approach of having to determine modification and reconstruction for each instance of controller maintenance, the pneumatic controller affected facility needs to be redefined as a process unit that groups all controllers at a single site.

17.4.4. Proposal for New Definition of Affected Facility

To summarize, from the above discussions, the pneumatic controller affected facility needs to be redefined to limit the category to continuous bleed gas-driven pneumatic controllers, grouped together at each site as a process unit affected facility thereby creating a single source that lowers the exposure to the methodology for determining modifications and reconstruction. API recommends that section §60.5365(d) be changed to read:

§60.5365

* * * * *

- (d) A continuous bleed gas-driven pneumatically controlled process unit ~~pneumatic controller~~-affected facility, which is defined as a single continuous bleed gas-driven pneumatically controlled process unit in VOC service. ~~pneumatic controller.~~

The recommended definition of a “continuous bleed gas-driven pneumatically controlled process unit” is then:

§60.5430

Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate all pneumatically controlled valves that regulate a process variable (such as flow, fluid level, pressure, or temperature of gas and liquids) located at a single site such as a well site, tank battery, or compressor station. This group of equipment includes instrument gas supply lines, filters, pressure regulators, floats and switches, continuous bleed gas-driven pneumatic controllers, valve actuators, and valves.

Precedent for this approach is found in the preamble discussion of the NSPS Subpart YYY proposal [59 FR 46780, 09/15/94], in which EPA states:

Defining the affected facility on a process unit basis avoids the problems associated with having multiple individual collection and treatment system equipment components classified as affected facilities, and it also provides a definition sufficiently narrow in scope so as not to preclude the possibility that existing sources will become subject to the NSPS through the modification and reconstruction provisions. Most importantly, defining an affected facility as a process unit reflects industry construction practices. Almost all new construction, reconstruction, and modification in the SOGMI is carried out by process unit.

After carefully considering each of the above alternatives, the EPA selected process

units as the basis for defining affected facilities for the proposed NSPS. This definition allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards.

The last sentence of the first paragraph quoted from 59 FR 46780 above is certainly applicable to pneumatic controllers. A new controller is not constructed by itself, as it would have no function. It is constructed as part of a whole unit construction where each component in our recommended unit definition is a necessary part for a pneumatically controlled valve to operate.

Accepting the arguments above, the pneumatic control process unit affected facility should then be defined as a single continuous bleed gas-driven pneumatically controlled process unit in VOC service.

Accepting the process unit approach, specifying an emissions rate for low bleed controllers, §60.5390(c) is recommended to read:

§60.5390

* * * * *

- (c) Each [weak stream vent from a continuous bleed gas-driven pneumatically controlled process unit](#) ~~pneumatic controller~~ affected facility [in VOC service](#) not located at a natural gas processing plant (as defined in §60.5430) must have natural gas emissions no greater than 6 standard cubic feet per hour. [Compliance with this emissions standard must occur according to the schedule in paragraph \(c\)\(1\) or \(c\)\(2\).](#)

17.4.5. Alternative Proposal for a Process Unit Affected Facility

If EPA refuses to aggregate all pneumatic controllers and associated equipment at a site into a single process unit affected facility, as discussed above in Section 17.4.4, then API alternatively suggests that a pneumatic controller process unit be defined in terms of all of the equipment utilized in a single control loop. This alternative can be implemented by simply amending the definitions of a “pneumatically controlled process unit” and “continuous bleed gas-driven pneumatically controlled process unit” recommended in Section 17.2.2 to:

[Pneumatically controlled process unit means the group of equipment required to operate a single pneumatically controlled valve that regulates a process variable \(such as flow, fluid level, pressure, or temperature of gas and liquids\). This group of equipment includes instrument gas supply lines, filters, pressure regulator, float and switch, pneumatic controller, valve actuator, and valve.](#)

[Continuous bleed gas-driven pneumatically controlled process unit means the group of equipment required to operate a single pneumatically controlled valve that regulates a process variable \(such as flow, fluid level, pressure, or temperature of gas and liquids\).](#)

[This group of equipment includes instrument gas supply lines, filters, pressure regulator, float and switch, continuous bleed gas-driven pneumatic controller, valve actuator, and valve.](#)

17.4.6. Benefits of Using a Pneumatically Controlled Process Unit as the Affected Facility

The above recommended change to the pneumatic controller affected facility would mitigate four issues. First, it would alleviate the inherent problem of a single pneumatic controller potentially triggering modification or reconstruction, but would preserve this trigger if major changes were made to the unit as a whole requiring a higher bleed rate. RMRR of a component of an affected facility is not likely to trigger reconstruction since the cost of the entire affected facility is the denominator in the cost analysis.

Second, there would be a significant reduction in the burdensome recordkeeping and reporting requirements which as currently proposed provides a disincentive to voluntarily replacing existing high bleed controllers with new low bleed controllers.

Third, and important to ozone nonattainment areas, using a process unit affected facility would preserve the ability for operators to capture offsets if they voluntarily change existing pneumatic controllers from high bleed to low bleed or intermittent vent. Changing out the controller would be changing a component part of the process unit affected facility but would not be the replacement of an affected facility that would otherwise trigger a new affected facility subject to this rule.

Fourth, defining pneumatic controllers as individual facilities could result in some states requiring that each continuous bleed pneumatic controller to be permitted prior to new construction, modification, or reconstruction for minor or major sources. By changing the affected facility definition to a pneumatically controlled process unit, permitting of individual controllers is not required if installation or replacement of an affected facility component occurs that might otherwise trigger modification or reconstruction. If API's recommendation to define pneumatics as a process unit is rejected, we request a note in the preamble to the effect that EPA does not intend that the installation of a single pneumatic controller would trigger permitting requirements. While this is ultimately a State issue, it would be helpful to have such a statement from EPA.

17.4.7. Continuous Bleed Gas-Driven Pneumatically Controlled Process Unit

Finally, assuming EPA agrees with API's recommendations, for consistency and clarity, every reference to "pneumatic controllers" used in the proposed rule for the affected facility should be changed to "continuous bleed gas-driven pneumatically controlled process unit".

17.5. Sitewide Applicability by Driver Medium

To complement affected facility applicability by the driver medium, which API recommends to be gas-driven only, determination of an affected facility for pneumatic controllers or pneumatic process units can be made on a sitewide basis, rather than by each individual controller. This will be much

less burdensome to an operator, as individual records of each controller are unnecessary. When compressed air is available to drive pneumatic controllers at any oil and gas site, it will be available to drive all controllers.

17.5.1. Natural Gas Processing Plants Have No Affected Facilities

In the proposal, EPA regulates pneumatic controllers with no emissions at natural gas processing plants due to the requirement for plants to use compressed air as the pneumatic driver to achieve zero emissions of natural gas. Recordkeeping and reporting is required for individual controllers which will be extremely burdensome. API knows of no precedent where a facility with no emissions of a regulated pollutant is regulated by an NSPS or other rule under the CAA. It would be much simpler if EPA prohibited the use of gas-driven controllers in VOC service. A plant using instrument air could then easily prove inapplicability to the rule by a single demonstration of the driver gas used to operate pneumatic controllers.

One exception is needed, however. Some operators may choose to use natural gas as the pneumatics driver for emergency and isolation valves, or switch instrument air to natural gas in the event of an emergency. If an emergency exists during a power outage, electric drive air compressors may not be functional to dependably supply needed compressed air to close emergency isolation valves. Operators need the flexibility to use natural gas as the driver, since it will be a dependable supply of gas available for emergency use.

17.5.2. Remote, small facilities

There are several categories of facilities such as Dew Point Suppression Facilities that are remote, unmanned, and have no available power, but meet the §60.5430 definition of a "Natural gas processing plant". Consequently, they do not have a method for meeting the §60.5410(d)(2) requirement of emitting zero natural gas. There is not always a cost-effective way of providing a reliable source of compressed air to be used as the driver for the pneumatic controller, so natural gas must be used. API's recommendation is either to accept API's proposed definitions for natural gas processing plant (gas plant) and forced extraction of natural gas liquids (see Section 6.3), or to exempt these remote facilities from the requirements of §60.5410(d)(2).

17.5.3. Use of Instrument Air at Other Oil and Gas Sites

While it is true that oil and gas sites are frequently remote and do not have access to reliable power supplies, it is not universally true. If a site does have access to reliable power, and if an operator decides that his process requires a high-bleed controller, he should have the option of installing instrument air if he decides that the combination of high-bleed controller and an air compressor provides a better process result. EPA's proposed rule language does not anticipate or allow this zero-emissions option. API provides rule text language in Attachment C that addresses this issue as paragraph §60.5390(c)(2). Switching to instrument air should be encouraged since it will reduce emissions from all controllers at a site. However, API recommends allowing 180 days for this to occur due to the extra time it takes to order and construct an air compressor.

17.6. Natural Gas is Not a Valid Surrogate for VOC

As discussed in General Issue section 5.1.1, there is no basis for the statement in §60.5390 to use natural gas as a surrogate for VOC. EPA assumed that natural gas contains 18% VOC, but the content varies widely. In fact, most unconventionally produced coal bed methane and shale gas has little if any measureable VOC. Additionally, natural gas downstream of an NGL fractionation or extraction gas plant has little or no VOC as VOCs are removed by processing. Further, gas analysis of process streams used for instrument gas are readily available and it is not difficult to use a VOC threshold directly. As stated in Section 5.1, pneumatics not in VOC service should be exempt from the rule.

17.7. Administrator's Approval for Use of High Bleed Pneumatic Controllers

Both §60.5390(a) and §60.5410(d)(1) state: "You have demonstrated, to the Administrator's satisfaction, the use of a high bleed gas-driven pneumatic controller device is predicated..." This suggests that prior approval from the EPA is required before high bleed pneumatic controllers are installed. If this is the intent, then it is a completely unworkable requirement. Construction and maintenance of pneumatic controllers cannot wait weeks or months for agency review and approval, as this would be very costly in terms of lost production while waiting to commence construction or maintenance. As well, EPA would be inundated with requests for approval if this is the expectation, and could not possibly process them in a timely manner.

Our suggested rule text changes in Attachment C delete use of the term "Administrator's satisfaction." If EPA deems use of the term necessary, then API requests clarification that prior approval is not the intent for its use and recommends that rule text in both section be changed to:

"You have maintained adequate records to support your decision that the use of high bleed gas-driven..."

17.8. Annual Reporting Requirements for Pneumatic Controllers

With an estimated 20,000 new gas and oil wells per year and an average of 3 controllers per well, there will be approximately 60,000 new pneumatic controllers installed each year. Additionally, according to EPA's own estimate pneumatic controllers have a 7-year service life^{LL}. This means approximately 1/7th of existing controllers will need replacement annually. There are approximately 3 controllers per well and 1 million existing wells so 1/7th of the controllers is 429,000 controllers. There are approximately 3 controllers per well and 1 million existing wells so 1/7th of the controllers is 429,000 controllers. If even 1/3 of that number is "continuous bleed, gas-driven pneumatic controllers" then 20,000 new controllers and 143,000 replacement controllers will create 163,000 new potentially affected facilities and reports each year. The administrative burden to industry will be overwhelming, just as it will be to state agencies and the EPA. It does not seem possible to demonstrate the benefit of these reports for such small sources, especially when agencies will be unable to review them. API is not supportive of a third party verification system, an idea raised in the preamble. see Section 8.8

^{LL} Page 2-16 of EPA 430-R-93-012, October, 1993 "Opportunities to Reduce Anthropogenic Methane Emissions in the United States"

If EPA refuses to exempt pneumatic controllers from the reporting requirements, then adopting API's recommendation for redefining the affected facility as a continuous bleed gas-driven pneumatically controlled process unit, will provide significant relief to the reporting burden. An initial annual report for each site that constructs a new, modified, or reconstructed process unit using one or more high bleed gas-driven controllers would be all that is necessary. Such a report would only need to include an explanation of why high bleed controllers are being used. Replacement and repair of controllers for existing facilities would normally not require additional reporting since modification or reconstruction would be seldom triggered.

17.9. Recordkeeping

API recommends that only records sufficient to demonstrate compliance with the rule be required. These records would include a sitewide applicability determination by documenting the medium for the pneumatic driver (e.g., air or gas). If the pneumatic driver is air or other gas not in VOC service, then that is the only record needed.

For sites with gas-driven pneumatics, records of controller make and model should then be sufficient but only for process unit affected facilities newly constructed, modified, or reconstructed after the proposal date. Knowing the make and model of controllers is sufficient to validate design specification to demonstrate compliance with the rule.

Records of installation dates are not possible for existing controllers as these are small components for which operators have not had any historical reason to track installation date. Furthermore, controllers are not date stamped with any manufacturing information. Only new controllers installed after Aug. 23, 2011 can be determined, since this proposal is the first time operators have had a demonstrated need to track this kind of information. These records can be made available by agency request or during a site inspection.

17.10. Time Extension for Manufacturer's Guarantee

The requirement in §60.5410(d)(3) specifies that "manufacturer's design specifications guarantee..." establishes a design standard. Currently, there is not a consistent manufacturing-industry practice to label pneumatic controllers or provide documentation with a bleed rate for the weak stream or to correctly specify if a controller is "high bleed" or "low bleed" based on the weak stream constant bleed rate. Since there is no industry standard, this leads to inconsistency amongst manufacturers in how they represent the performance of their products. If it is EPA's intention to establish regulations that require equipment manufactures to standardize the performance representation of their products so that performance is guaranteed, and to have them produce specific labeling, specific documentation, and/or specific performance parameters, then that intention needs to be a requirement directed to the equipment manufacturers. Other NSPS regulations have been accompanied with a grace period to allow manufacturers to conduct meaningful testing, develop necessary documentation, and alter required equipment name plates. API recommends that this grace period be 2 years. If it was not EPA's intent to require a manufacturer guarantee or certification, then API recommends that the term "guarantee" in §60.5410(d)(3) be replaced with "verify" (and the rule text be changed as recommended in Attachment C for §60.5420(b)(5)(iii) and §60.5420(c)(4)(iii)) to avoid confusion and misinterpretation.

17.11. Extend Compliance Date for Pneumatic Controllers by One Year

Unlike the large emission sources regulated in other NSPS Subparts, operators, manufacturers, and suppliers keep inventories of extra pneumatic controllers in stock as they are relatively inexpensive, and malfunctions require quick repair or replacement to maintain production. A compliance date of only 60 days after promulgation will make large inventories of high bleed controllers potentially unusable. Time is needed for manufacturers, suppliers, and operators to make inventory adjustments to adapt to the new requirements. Consequently, API requests the effective date of this rule for pneumatic controllers be delayed for one year past the promulgation date to allow companies to make inventory adjustments. Additionally, a one year extension will also give operators time to switch to instrument air, if feasible as an alternative control strategy. Switching to instrument air, where practicable, should be a desired outcome of this rule proposal since it will eliminate emissions of natural gas.

18. COMPRESSORS

GENERAL COMPRESSORS

18.1. Does Moving Compressors from One Location to Another Trigger Construction (i.e., Installation)?

In §60.5365, EPA states clearly that affected facilities listed in paragraphs (a) through (g) that commenced construction, modification, or reconstruction after August 23, 2011 are subject to the applicable provisions. However, in paragraphs §§60.5365(b) and (c), EPA includes confusing and unnecessary language for determining when a compressor is considered an affected facility. The specific sentences are bolded below:

§60.5365(b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor located between the wellhead and the city gate (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. **For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.**

§60.5365(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor located between the wellhead and the city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. **For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.**

If you breakdown the sentence for when a facility becomes an affected facility, then four clarifying words are important and discussed in detail in the General Provisions under the Definition section (§60.2), the Modification section (§60.14), and the Reconstruction section (§60.15). In §60.2, commenced construction is sufficiently defined as:

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

As you can see from the definitions above, commenced construction includes installation and is based on when the operator enters a contractual obligation to construct or modify an affected facility. Therefore, the last sentences in §60.5365(b) and (c) are unnecessary and could be incorrectly interpreted to apply to existing compressors that are relocated from one location and installed at another without being modified or reconstructed according to the criteria of §60.14 or §60.15.

In addition to removing the confusing reference to "installed" as it relates to commenced construction, EPA should include in the response to comment that the historical position of relocation has not changed for facilities under NSPS OOOO. Some of the rationale and historical decisions are:

- Air pollution controls are generally more effective and less costly when designed as part of the original production facility, rather than retrofitted to an existing facility. Thus, the Clean Air Act amendments established the New Source Performance Standards (NSPS), which requires technology-based emission limitations on "new" sources of air pollution in certain designated industrial categories. It makes little sense in the context of section 111 of the Clean Air Act, to treat as new sources, equipment that was designed and built before the proposal date of an NSPS rule, because it is much less cost effective to retrofit these existing sources. For this reason, EPA appears to have adopted the rule that relocation of an existing source does not trigger NSPS. For this same reason, the installation date should not be used as a trigger for NSPS application to existing equipment. This is consistent with other actions taken by EPA, such as in the RICE and CI NSPS rules:

§60.4208 (h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

The engine and compressor are typically a package unit. When an engine is relocated, the associated compressor is relocated at the same time. If a relocated engine is not considered a modification or reconstruction under NSPS JJJJ or IIII, then EPA should also not consider a compressor relocated with the engine as a modification or reconstruction. Maintaining consistency between the NSPS's will avoid the confusion of having differing NSPS applicability for portions of a packaged unit being relocated to another location.

- Several EPA ADI's have clearly determined that relocation without a modification or reconstruction does not trigger NSPS. Refer to the following ADI's for more details on EPA's historical policy:
 - K003 (1978) – "EPA policy is that relocation of existing facilities does not constitute a modification under 40 CFR 60.14."

- 0900067 (2008) – "Relocation in and of itself does not trigger applicability."

To avoid the confusion and maintain consistency with the NSPS general provisions and historical position, API recommends EPA remove the last sentence from each section. The recommended change is reflected below:

Suggested Rule Text:

§60.5365

* * * * *

- (b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor in VOC service located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) and prior to the natural gas processing plant is not an affected facility under this subpart. ~~For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~
- (c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor in VOC service located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. ~~For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.2. Applicable Provisions for Compressor Located at an Onshore Natural Gas Process Plant

Clarify the applicable provisions for compressors located at an onshore natural gas processing plant. In §60.5365(b) & (c), compressors between the wellsite and the city gate are affected facilities, which are subject to the standards in §60.5380 and §60.5385. In §60.5365(f), compressors and equipment at onshore natural gas processing plants are an affected facility. Affected facilities under §60.5365(f) are subject to the VOC control requirements found in §60.5400, §60.5401, and §60.5402, which reference the LDAR requirements in NSPS VVa. Although NSPS VVa contains requirements for compressors, EPA did not reference the compressor standards found in VVa. The inclusion of compressors in both affected facility descriptions causes confusion as to the applicable requirements under NSPS OOOO. In Chapter 6 of the technical support document (TSD), EPA includes compressors located in the processing category (natural gas processing plants) in the regulatory options evaluation under §60.5380 and §60.5385. In Chapter 8 of the TSD (Equipment Leaks), page 8-21, EPA states "Compressors are not included in this LDAR option and are regulated separately." Therefore, it appears EPA intends to regulate affected compressors under §60.5380 and §60.5385 and not under the LDAR requirements for natural gas processing plants. To avoid confusion as to the appropriate requirements for the compressor affected facility, API recommends the following changes to the applicability section in §60.5365:

Suggested Rule Text:**§60.5365**

* * * * *

(f) ~~Compressors and~~ Equipment (as defined in §60.5430) located at onshore natural gas processing plants.

~~(1) Each compressor in VOC service or in wet gas service is an affected facility.~~

~~(2)~~(1) The group of all equipment, ~~except compressors~~, within a process unit is an affected facility.

RECIPROCATING COMPRESSORS**18.3. Rod Packing Change Out****18.3.1. Extend the Time Period to 43,800 Hours or the Option for Every 5 Years**

EPA's cost-benefit analysis does not account for the cost of downtime. EPA assumes the rod packing replacement is completed during a normally scheduled maintenance shutdown. Major maintenance and overhauls are typically completed on a 5 year cycle. In addition, packing sets are either "continuous" or "split ring". Split ring packing allows for replacement without removing the pistons from the cylinders, but is more prone to leak and some companies do not allow the use of a split ring packing for that reason. Continuous packing is less prone to leakage, but replacement requires pulling the piston and rod out of the cylinder which is a major effort that is only done on major compressor overhaul cycles generally every 5 years. Therefore, the rod packing replacement schedule should be changed to allow the option for every five years or 43,800 hrs in order to meet EPA's intent of not including downtime in the cost-benefit analysis and to coincide with a common frequency for major maintenance. Allowing the option for a set 5 year frequency will simplify the recordkeeping and eliminate the need to track operating hours. For owner/operators having a method to track operating hours, the option to replace the packing every 43,800 hours may be a preferable option.

18.3.2. Tracking Hours of Operation

The requirements of §60.5385(a) imply that the hours of operation of reciprocating compressors must be continuously monitored beginning upon the initial start-up, the date of publication of the final rule, or the date of the previous rod packing replacement. Although not specifically stated as a requirement, it could be interpreted that a "hour meter" be installed on all "engine-compressor" sets to continuously monitor runtime hours. There are other methods of monitoring runtime, such as "telemetry and periodic downloads associated databases", that do a reliable job of tracking hours of operation. EPA should clarify that hours of operation can be monitored using a runtime meter, telemetry and associated database, or other system (maintenance logs, PM databases, or work order tracking system) used to track preventative maintenance schedules.

18.3.3. Option for Preventative Maintenance and Inspection Programs

EPA should include an option for Owner or Operator to rely on preventative maintenance programs for determining a leak from the rod packing, subsequently requiring replacement. The maintenance plan typically contains normally scheduled rod packing frequencies changes to coincide with major preventive maintenance performed during a shutdown. Many owner or operators have a preventative maintenance programs that include periodic inspections and maintenance to ensure the compressor and engine driver are operating properly for maximum reliability. An example of an inspection that is sometimes performed to verify the condition of the rod packing seal, is to conduct a quarterly ultrasound measurements for indications of leak. If a leak is detected, the compressor is scheduled for shutdown and repair. The expert opinion of several reciprocating compressor engineers is that the replacement should be based on inspection/measurements to determine the compressor condition (including rod packing seals) and should not be based on time alone. New packing has a break-in period where the leakage can be higher than it would be for older packing. In addition, the failure of new seals due to installation problems or manufacturing defects is not uncommon. If you also account for the additional emissions that are likely to be released when preparing the compressor for maintenance, a time-based replacement program would probably result in higher emissions than a condition based program. For an engine subject NSPS JJJJ, the owner or operator is required to have a maintenance plan to ensure the engine is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions. Since many of the affected compressors under NSPS OOOO will be associated with an engine subject NSPS JJJJ, EPA should be consistent between the standards and allow for the option to use a preventive maintenance plan under NSPS OOOO.

18.3.4. Suggested Rule Text

§60.5385

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

- (a) You must replace the reciprocating compressor rod packing before the compressor has operated for [a period longer than one of the limits listed in paragraphs \(a\)\(1\) through \(a\)\(3\) of this section](#) ~~26,000 hours~~. The number of hours [or years](#) of operation must be ~~continuously~~ monitored beginning upon initial startup of your reciprocating compressor affected facility, or [60 days from](#) the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. [If monitoring the number of hours of operation, the hours can be monitored using an associated engine runtime meter, telemetry and associated database, or other system \(maintenance logs, PM databases, or work order tracking system\) used to track preventative maintenance and schedules.](#)

[\(1\) 43,800 hours; or](#)

(2) five years; or

(3) a frequency specified by the owner or operator in a preventative maintenance plan designed to maximize the reliability of the reciprocating compressor and minimize VOC emissions.

§60.5415

(c)(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches the limit selected by the owner or operator from §60.5385(a)(1) through (a)(3) ~~26,000 hours.~~

§60.5420

(b)(4) For each reciprocating compressor affected facility, ~~the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.~~

~~(i) The cumulative number of hours of operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.~~

~~(ii) Documentation that if the reciprocating compressor rod packing was due for replacement according to one of the frequencies described in §60.5385(a), but was not replaced as specified before the cumulative number of hours of operation reached 24,000 hours.~~

18.3.5. Ownership

The compressor owners (i.e. rental companies) should be responsible for rod packing change outs and recordkeeping.

18.4. Exclude Reciprocating Compressors in the Transmission and Storage Segment

EPA should exclude reciprocating compressors in the transmission and storage sector, located after the point of custody transfer, due to the low VOC content of natural gas in that sector. A more detailed discussion can be found in Sections 3 and 5.1.

Suggested Rule Text:

§60.5365

* * * * *

(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor in VOC service, located between the wellhead and the point of custody transfer city gate (as defined in §60.5430), except that a reciprocating compressor located at a well site (as defined in §60.5430) is not an affected facility under this subpart. ~~For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.5. Reciprocating Compressor Definition

The definition should be changed to a more accurate description. API recommends the following definition:

Suggested Rule Text:

§60.5430

Reciprocating compressor means a [positive-displacement machine in which the compressing and displacing element is a piston having a reciprocating motion within a cylinder. The pressure increase is achieved by reducing the volume of a fixed amount of natural gas or field gas](#) ~~piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.~~

18.6. Typographical Error

It appears there is a typographical error in §60.5420(b)(4)(ii). This paragraph references documentation for the reciprocating rod packing being replaced before reaching 24,000 hours. However, the proposed standard in §60.5385 requires replacement of the rod packing every 26,000 hours.

CENTRIFUGAL COMPRESSORS

18.7. Exclude Centrifugal Compressors in Gathering and Boosting and Transmission Segments

In Chapter 6 of the Technical Support Document (TSD), the evaluation for centrifugal compressors is limited to only centrifugal compressors in processing, transmission, and storage. The cost-benefit analysis does not include centrifugal compressors located in production or gathering and boosting. EPA accurately exempted centrifugal compressors located at a wellsite as an affected facility. However, a centrifugal compressor located in the gathering and boosting segment was considered an affected facility without the necessary cost-benefit analysis to support this decision. EPA should revise the affected facility description to accurately reflect the TSD and basis for determining an affected facility for centrifugal compressors.

Because of the low VOC content, EPA should also exclude centrifugal compressors in the transmission and storage segment, located after the point of custody transfer. A more detailed discussion can be found in Sections 3 and 5.1.

Suggested Rule Text:

§60.5365

- (b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor [in VOC service](#) located between the wellhead and the [point of custody transfer](#) ~~city gate~~ (as defined in §60.5430), except that a centrifugal compressor located at a well site (as defined in §60.5430) [and prior to the natural gas processing plant](#) is not an affected

facility under this subpart. ~~For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.~~

18.8. Allow for a Wet Seal Option for Centrifugal Compressors

Although EPA indicates controls for wet seals are not cost-effective, recent information indicates this is not correct and EPA should not preclude the use of a wet seal equipped centrifugal compressor with controls capable of meeting a 95% VOC control efficiency or routing captured seal-oil gas to a fuel gas system, recycle, or another processing system.^{MM} Centrifugal compressors located at natural gas processing plants may have wet seal compressors with a seal-oil degassing recovery system that separates gas from the seal-oil and routes the separated gas back to compression suction, fuel system, or flare system. For example, many Solar® compressors packages will have a seal oil system. But, the system does not vent the seal gas to atmosphere. The oil and gas mixture that drains from the seals is routed through a seal oil trap that separates the oil and gas. The oil is returned to the package oil tank. The gas is returned to the compressor suction. In the case of existing wet seal centrifugal compressors which may become subject to NSPS OOOO due to modification or reconstruction utilizing an existing gas capture system or retrofitting the centrifugal compressor with a seal oil vapor separation and control system is far more cost-effective than installing a dry gas seal compressor. Conversion of a wet seal centrifugal compressor to dry seals costs from \$250,000 to \$1,000,000 per machine while retrofit with a seal oil gas separator is estimated to cost in the range of \$22,000¹. This option would also provide flexibility for cases where the owner/operator believes a dry gas seal system is not technically feasible (e.g., “dirty” gas) or believe the wet seal system is more economic for the specific location and service. This will also allow compressors with wet seals installed between the date for an affected facility and the final rule to be able to install necessary controls or process modifications rather than retrofit a dry gas seal system.

The preliminary results from a joint EPA (Natural Gas STAR) and BP study of these types of seal-oil gas recovery systems in place on wet seal centrifugal compressors at BP's Alaska North Slope operations were co-presented by BP and ICF (as EPA's contractor) at the Global Methane Initiative (GMI) meeting in Krakow, Poland on October 14, 2011. As the preliminary results illustrate, seal-oil gas separation systems have atmospheric vent volumetric rates broadly similar to dry seal leak rates and may perform incrementally better in some instances. Although EPA and BP have additional work prior to publishing detailed results of the study the preliminary results are quite compelling and should be adequate basis for allowance of this option. A full copy of the presentation in Krakow can be downloaded at the GMI website.^{NN}

^{MM} Routing Centrifugal Compressor Seal Oil De-gassing Emissions to Fuel Gas as an Alternative to Installing Dry Seals”; Global Methane Initiative All-Partnership Meeting; Oil and Gas Subcommittee – Technical and Policy Sessions; October 14, 2011 Krakow, Poland; Reid Smith-BP & Don Robinson-ICF

^{NN} http://www.globalmethane.org/documents/events_oilgas_101411_tech_smith2.pdf

Suggested rule text to accommodate the option of using a wet seal gas system:

§60.5380

You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility.

- (a) You must control VOC emissions from centrifugal compressors using one the methods described in paragraph (a)(1),(a)(2), or (a)(3). ~~equip each rotating compressor shaft with a dry seal system upon initial startup.~~

(1) Equip the rotating compressor shaft with a dry seal system upon initial startup.

(2) Equip the rotating compressor shaft with a wet seal-oil degassing system and route the separated gas to one of the following:

(i) a flare designed and operated in accordance with the requirements of §60.18(b), or

(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.

(iii) a combustion device designed to reduce VOC emissions by 95%, or

(iv) a fuel system, or

(v) recycle (compression suction), or

(vi) a combination of (2)(i) through (2)(v)

(3) Equip the rotating compressor shaft with a wet seal. You must route the seal oil degassing tank vapors through a closed vent system to one of the following:

(i) a flare designed and operated in accordance with the requirements of §60.18(b), or

(ii) a flare designed and operated in accordance with the requirements of §60.18(b), except §60.18(c)(2) and (f)(2). An electronic flare ignition device shall be used to satisfy the requirement for an ignition system when a VOC stream is sent to the flare.

(iii) a combustion device designed to reduce VOC emissions by 95%, or

(iv) a vapor recovery device routed to a combustion device designed to reduce VOC emissions by 95%; a fuel system, or recycle (compression suction/process), or

(v) a combination of (3)(i) through (3)(iv).

§60.5410

* * * * *

- (b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted ~~with a dry seal system~~ upon initial startup as required by §60.5380.

§60.5415

* * * * *

- (b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped ~~with a dry seal~~ as specified in §60.5380(a).

§60.5420

* * * * *

- (b)(3) For each centrifugal compressor affected facility installed during the reporting period, documentation ~~that if~~ the centrifugal compressor ~~is was not~~ equipped ~~with dry seals~~ as specified in §60.5380(a).

18.9. Centrifugal Compressor Definition

Centrifugal compressors associated with vapor recovery should be excluded from the definition because shutdowns to replace seals would increase emissions as compared to waiting for the next scheduled process unit shutdown. Certain centrifugal compressors are designed to capture and route vapors back into the process to prevent or reduce emissions. The design necessary to efficiently capture and control emissions should be left to the manufacture and not EPA. EPA should make it clear that the definition of centrifugal compressor does not include compressors associated with vapor recovery.

The definition should be changed to more accurately describe affected facility. API recommends the following definition:

Suggested Rule Text:

§60.5430

Centrifugal compressor means a dynamic machine in which one or more rotating impellers, usually shrouded on the sides, accelerate the flow of natural gas or field gas. The main gas flow is radial. The pressure increase is achieved by converting kinetic energy to static energy. Centrifugal compressor does not include compressors associated with vapor recovery or any other pollution control device ~~piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.~~

19. EQUIPMENT LEAKS

API fully supports EPA's determination not to propose NSPS for addressing VOC emissions from equipment leaks at exploration and production field facilities. However, API has a number of concerns and issues with

regard to EPA's proposed revisions to NSPS and NESHAP addressing VOC/HAP emissions from equipment leaks at natural gas processing plants.

19.1. Subpart OOOO – Stringency of Subpart VVa Requirements

EPA states that their technology review has led them to propose that the requirements at 40 CFR Part 60, Subpart KKK for controlling VOC emissions from equipment leaks at natural gas processing plants be updated to reflect the requirements in 40 CFR Part 60, Subpart VVa. EPA indicates that it has evaluated four options for updated control requirements and is proposing a program that is largely based on the equipment leaks standards promulgated under 40 CFR 60 Subpart VVa. The leak detection and repair (LDAR) program prescribed in Subpart VVa requires the monitoring of pumps, pressure relief devices, valves, and connectors. These components are monitored with an Organic Vapor Analyzer (OVA) or Toxic Vapor Analyzer (TVA) to determine if a component is leaking by measuring the concentration of the mixture of organic compounds at the potential leaking interface. Connectors, valves, and pressure relief devices are defined as leaking if the concentration is equal to or greater than a threshold of 500 parts per million by volume (ppmv); pumps are defined as leaking if the concentration around the seals equals or exceeds 2,000 parts per million. Valves and pumps are monitored monthly, connectors are monitored annually, and atmospheric pressure relief valves are monitored after a pressure release event. Open-ended lines must be capped or plugged when not in use or must be equipped with a second valve.

19.1.1. Proposed LDAR Program for Valves

EPA overestimated valve control-effectiveness for its model plant.

The natural gas processing plant model used by the agency in its technical support document (TSD) to analyze the impact of these new leak definitions for the LDAR program is flawed. EPA correctly states that New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, Subpart KKK), and were assumed to be the baseline emissions for this analysis. However, the calculations of baseline emissions for the model plant - as presented in the TSD - significantly overestimate these emissions since the method used relies on component counts and average emission factors by component type, which are, *at best, representative of uncontrolled facilities*. Since Subpart KKK was promulgated in 1985, a significant proportion of the existing natural gas plants that would become subject to Subpart OOOO through modification will already be complying with Subpart KKK, and all new natural gas plants would have to comply with Subpart KKK if Subpart OOOO was not in place. Thus, the basis for evaluating Subpart OOOO impacts must be compliance with Subpart KKK, not an uncontrolled emissions scenario as was used in EPA's TSD analysis that supports the proposed rule.

Table 8-12 of the TSD provides a listing of estimated control effectiveness (CE) for select LDAR programs at a Chemical Process Unit and a Petroleum Refinery. The CE for a quarterly LDAR program with a 10,000 ppm leak definition is assumed to be in the range of 60% to 70%, which is assumed to be applicable also for natural gas processing plants that are subject to 40 CFR 60 Subpart KKK. In the TSD, EPA used baseline VOC emissions of 14.3 tons /yr for its model natural gas processing plant facility. This baseline is in error

because it represents emissions from an uncontrolled facility. A more realistic value, based on applying the CE stated above to EPA's uncontrolled emissions estimate, would be in the range of 4.3 to 5.7 tons/yr, per facility. This range of values accounts for the CE of Subpart KKK controls, and should be used as the baseline from which it is appropriate to calculate the incremental impact of the proposed regulations.

The TSD model calculates uncontrolled emissions using average emission factors that typically overestimate emissions when compared to calculation methods that are based on Leak/No-Leak factors, or the correlation equation approach when the screening value details are available. This overestimate occurs, among other reasons, because the average emission factors assume a much higher percentage of leaking components than those that are typically found at facilities where monitoring programs, such as the ones imposed by Subpart KKK, are in place. The table below provides a comparison of VOC emissions calculations for valves from several natural gas processing plants. The results in the table are based on using the Average Emission Factor vs. the Leak/No Leak methods for the same facilities. The data are based on examples provided by API members for process units that are currently subject to Subpart KKK. The computed percent difference is an indication of the overestimate of valves emissions due to using an average emission factor.

Table 19-1 Comparison of VOC Emissions Calculations For Valves From Natural Gas Processing Plants

Facility	VOC Emissions from Valves (tons/year)		% Difference
	Average Emission Factor	Subpart KKK (Leak/No Leak)	
A	5.7	1.36	76%
B	8.2	1.54	81%
C	0.98	0.0055	99%
D	6.73	0.20	97%
E	4.0	0.19	95%
F	19.4	17.00	12.4%

By overestimating the baseline emissions for the model plants, as well as the emission reduction associated with applying the VVa program to facilities that are otherwise subject to a Subpart KKK program, the TSD derives an estimated VOC emission control effectiveness for this proposal of 94%; which is not realistic nor is it representative of the incremental control that might be attained from a Subpart KKK baseline.

API's data demonstrated EPA's overestimation.

Based on data provided by API member companies for several natural gas processing plants that are currently subject to 40CFR60 Subpart KKK, the percent of valves that leak above 10,000 ppm ranges between 0.1 - 4.0%; however, these leaking valves contribute 82 - 99% of the total mass emissions from facility valves when using the Leak/No-Leak method from EPA's 1995 protocol for estimating emissions. This is consistent with an earlier API study (API # 310, November 1997) of petroleum refineries equipment leaks that showed that 92% of reducible emissions are due to only ~ 0.13% of components.

API obtained more detailed data for three different natural gas processing units where the actual parts per million concentration values monitored are recorded. This enables the use of the correlation equation method to calculate total emissions from valves and to estimate the contribution of valves that are leaking in various screening value ranges. The table below summarizes the available data. The data indicate that the existing Subpart KKK is contributing to controlling valve leakage above 10,000 ppm. About 80% or more of the valves monitored screen below 500 ppm, and the fraction that screens between 500 and 10,000 ppm ranges between 2-15%. The fraction of the valves that screens between 500 – 10,000 ppm is shown to contribute less than 30% to overall emissions from facility valves.

Table 19-2. Detailed Data for Valves from Three Natural Gas Processing Units

Process Unit	Screening Value Range	VOC Emissions (tons/yr)	% of Emission	Valve Count	% of Components
A	Less than 500 ppm	0.030	68.7%	677	97.8%
	Between 500 and 10,000 ppm	0.014	31.3%	15	2.2%
	TOTAL	0.044	100.0%	692	100.0%
B	Less than 500 ppm	0.301	15.9%	3759	87.0%
	Between 500 and 10,000 ppm	0.543	28.7%	527	12.2%
	over 10,000 ppm	1.049	55.4%	36	0.8%
	TOTAL	1.893	100.0%	4322	100.0%
C	Less than 500 ppm	0.182	1.6%	2058	80.9%
	Between 500 and 10,000 ppm	0.417	3.7%	385	15.1%
	Between 10,000 and pegged at 100,000	2.575	23.1%	73	2.9%
	Pegged 100,000	7.98	71.5%	29	1.1%
	TOTAL	11.154	100.0%	2545	100.0%

Hence, the proposed changes to the LDAR program for natural gas processing plants that will redefine leaking valves as those leaking above 500 ppm will not lead to any substantial VOC emissions reductions. Per the examples shown in the table above, for a facility that is either currently subject to Subpart KKK or, if new, would become subject to Subpart KKK, the overall VOC emissions from its valves are about 2 tons/year. Lowering the leak definition to 500 ppm might reduce VOC emissions by less than 0.6 tons/year. This is much lower than the 10.9 tons/yr postulated by EPA for the TSD model plant. Therefore, the proposed revised LDAR program for valves will be burdensome without achieving the VOC control claimed and, considering its poor cost effectiveness, does not represent the Best System of Emission Reduction (BSER) for natural gas plant equipment leaks, as required by the Clean Air Act (CAA) for New Source Performance Standards (NSPS).

19.1.2. Proposed LDAR Program for Connectors

EPA overestimated emission reductions.

The changes to the proposed LDAR program for natural gas processing plants includes introduction of a connector program with a leak definition of 500 ppm, which is based on similar programs for chemical and refinery units. Current Subpart KKK LDAR programs impose only auditory, visual and olfactory (AVO) inspection requirements for connectors. Based on the TSD model plant, EPA expects a VOC reduction of 1.57 tons/year for the model facility with the assumption of a CE of 95.9%. This amounts to about a 20% overestimate of the emission reduction potential when compared to the TSD citations of a 93% CE for a chemical plant, and an 81% CE for a refinery, both with a 500 ppm connector program (TSD Table 8-12).

Moreover, API has collected limited data from three natural gas processing facilities that voluntarily monitor and record screening values for connectors. The table below summarizes the data and it demonstrates - as expected - that connectors do not exhibit significant VOC emissions, and do not typically register concentrations over 10,000 ppm when monitored with VOC sniffers. For the process units analyzed, the number of connectors range from 1,463 to 11,272, and the corresponding emissions range from 0.076 to 1.77 tons per year of VOCs. For those process units 27 - 57% of the connectors are found to be in the screening value range of 500 and 10,000 ppm. When these data are normalized for a facility with an equivalent number of connectors as in the model plant, potentially reducible emissions from connectors are 0.87 tons VOC/year.

Table 19-3. Detailed Data for Connectors from Three Natural Gas Process Facilities

Process Unit	Screening Value Range	VOC tons/year	% Emissions	Connectors Count	% connectors
A	Less than 500 ppm	0.0087	11.4%	1069	73.1%
	Between 500 and 10,000 ppm	0.0672	88.6%	394	26.9%
	TOTAL	0.0759		1463	
B	Less than 500 ppm	1.5980	100.0%	11272	100.0%
	TOTAL	1.5980		11272	
C	Less than 500 ppm	0.4192	23.7%	2922	42.8%
	Between 500 and 10,000 ppm	1.3508	76.3%	3899	57.2%
	TOTAL	1.7700		6821	

Therefore, a value of 0.87 tons/yr of VOC emission reduction is a more realistic value than EPA's 1.57 ton/yr estimate to judge the effectiveness of the proposed connector program. This value and a more realistic CE than the 95.9% EPA assumed should be used to calculate the cost effectiveness of the proposed connectors program.

EPA underestimated the cost and overestimated cost-effectiveness.

EPA is proposing a connectors control program that is not cost-effective and thus not BSER. In fact, it is evident from the data presented and from a previous study of American Chemistry Council (ACC) member facilities⁰⁰ that there is no statistically significant difference in average connector emissions between the initial Method 21 inspections for connectors and the subsequent inspections. Thus, an LDAR program for connectors is ineffective in leading to significant emission reductions.

EPA is oversimplifying the cost assumptions by basing its entire cost effectiveness analysis on data it has previously developed for promulgating Subpart VVa in 2006. The TSD is based on the assumption that the same cost spreadsheets model used for chemical plants and refineries is also applicable for estimating the costs associated with monitoring at natural gas processing plants. This assumption is erroneous and does not take into account many additional factors that should be considered when assessing the cost impacts of a connectors monitoring program at gas plants. Factors that should be considered include:

- (a) Due to the high turnover associated with LDAR personnel and the annual monitoring interval for connectors, it is likely that each time connectors are monitored training will be required to acquaint the monitoring personnel with the process detail, adding to program costs.
- (b) Many natural gas plants are located in remote locations and monitoring personnel, maintenance personnel and even operators will have to travel significant distances to reach the site, incurring significant additional costs to those typical of chemical and refining operations.
- (c) From a recordkeeping perspective, connectors result in a much greater administrative burden than is incurred for other component types. Unlike pumps and valves, connectors are not typically shown on Process & Instrumentation diagrams. Valve end connectors may be identified in an LDAR database via the valve LDAR identification number, such that the connectors are not individually tagged. Both of these conditions make it much more difficult and costly to track additions or deletions of connectors and to maintain accurate component records.

If we review EPA's cost estimates of \$17.70 for the **initial monitoring and setup costs** for valves, and a mere incremental cost of \$1.13 per connector, it is immediately evident that these figures are grossly underestimated. Adding connectors to an existing monitoring system is costly. It will require expanding data collection and tagging systems to identify the connectors being added, and additional time for the associated logistical and planning aspects of an expanded program. Based on data provided by an API member, the costs for setting up a monitoring system for valves is over \$26 per valve (for a model plant consisting of 1500 valves). For the same such plant, the incremental cost for adding a connectors program would be in the range of \$3 - \$9.50 or more per connector (for a model consisting of 4400 connectors) depending on the exact nature of the existing LDAR program, the

⁰⁰ Exhibit 1 – CMA (ACC) Analysis of Connector Monitoring Data from Hazardous Organic NESHAP (HON) and Miscellaneous Organic NESHAP (MON) Units. Pages 15 through 37 of ACC's comments on proposed NSPS Subpart VV, Docket Number EPA-HQ-OAR-2006-0699, February 8, 2006.

adequacy of the existing data collection and archiving system and the amount of time that needs to be spent on site at remote locations.

Similarly, the assumed equivalency of cost (\$1.50 per monitoring event) for both valves and connectors does not reflect the true cost of monitoring connectors. For the reasons stated above connectors would cost more to monitor per component than valves. None of these costs are reflected in EPA's \$1.50 per component cost estimate. Based on data available from API members a more realistic estimate would be a cost of \$ 2.70 - \$ 3.00, or more, per connector monitoring event, depending on individual facility circumstances and location.

The calculation presented in the TSD lists the cost effectiveness for connectors in the range of \$4,800/ton-VOC. However, for the reasons discussed above, the proposed connector LDAR program is not expected to lead to the emission control estimated by EPA and thus, even if we accept the assumed costs used by EPA to add an incremental connectors program, the cost effectiveness figure would be much higher, something in the range of over \$7800/ton-VOC when the initial capital costs are amortized over 10 years. If more realistic setup and monitoring costs are considered as discussed above, the cost effectiveness for connectors would be on the order of \$14,100/ton-VOC based on average costs reported by a few API members. Moreover, under special circumstances such as very remote locations, and connectors that are hard to access (though would not be considered 'difficult to monitor') the costs might double or triple.

Cost effectiveness is even further diminished if a lower amortization period is used. The capital equipment investment needed for implementing an Equipment Leaks program consists primarily of monitoring equipment and data systems for data collection and analysis in addition to physical tags for the components. The required field equipment would probably have only a 5-year lifetime, due to on-going improvements in both monitoring instrumentation and hand-held devices. Using the 5-year lifetime for capital equipment amortization would lead to a revised cost effectiveness estimate that is over \$8,400/ton-VOC. If we are to apply the API data discussed above assuming a 5-year lifetime for the capital equipment purchased, the cost effectiveness increases to over \$17,000/ton-VOC.

API contends that the low emission reductions that could be attained by a connectors program would entail high incremental costs, rendering a connectors program not cost-effective.

19.1.3. Additional Cost to Repair Valves and Connectors

EPA did not account for the additional cost to repair valves and connectors at natural gas processing plant if a leak is defined as 500 ppm. In contrast with chemical plants and refineries, natural gas processing plants do not have all required maintenance personnel onsite. In order to perform the initial attempt at repair, they have to rely on contractor personnel and in many cases it would be a different 'trades' crew that is dispatched to perform the repairs as compared to the ones that conducted the monitoring and initial data collection. The additional annual costs for repairing valves and connectors to a more stringent leak definition of less than 500 ppm are significant. For a natural gas processing plant, similar to the model plant in the TSD, API estimates the incremental repair costs to

range from \$60,500 to \$121,000 with an average of \$90,750. These costs must also be accounted for in the Agency's BSER analysis prior to promulgating the new LDAR requirements.

API further affirms that the incremental cost of repair of valves and connectors, if the leak definition were to be reduced to less than 500 ppm, is an additional burden which is not justified in terms of its potential for VOC emission reductions.

19.1.4. Proposed LDAR Program for Pumps – BSER Not Demonstrated

EPA is proposing to lower the leak definition for all pumps from 10,000 ppm to 2,000 ppm. Such a requirement could be very costly, but EPA does not address these potential costs nor does it outline the potential for emission reductions due to such an amended program. As a matter of fact, EPA did not include pumps in its model plants for natural gas processing facilities and thus it is not justifying the extra burden and not demonstrating any environmental benefit.

The proposed leak definition for pumps would likely require different seal material. EPA must demonstrate the need for such a LDAR program for pumps and that these requirements are BSER. That demonstration has not been made and thus these requirements cannot be finalized. If the Agency intends to proceed with lower leak thresholds for pumps, the required BSER and other analyses must be published for notice and comment.

19.1.5. Reciprocating Pumps

Reciprocating pumps are much more common in oil and gas operations than in refining and chemical operations. A 2000 ppm or even a 5000 ppm leak definition will be difficult to meet for reciprocating pumps in general and will be impossible to meet for some reciprocating pumps, without recasting the distance piece or pump replacement. Replacement of such pumps or the pump distance piece was not considered in proposal development and does not reflect BSER.

§60.482-3a(j) of Subpart VVa deals with this issue for reciprocating compressors. That paragraph exempts existing reciprocating compressors from VVa requirements if the owner or operator can demonstrate that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance. The term "distance piece" is defined in Subpart VVa for compressors.

Similar provision and definition can be added to Subpart OOOO for reciprocating pumps.

Thus, API requests the final Subpart OOOO includes a provision similar to §60.482-3a(j) of Subpart VVa and a definition of "distance piece" relative to reciprocating pumps.

Suggested Rule Text**§60.5401**

* * * * *

(i) Any existing reciprocating pump in a process unit which becomes an affected facility under the provisions of §60.14 or §60.15 is exempt from §60.482-2a of this part, provided the owner or operator demonstrates that recasting the distance piece or replacing the pump are the only options available to bring the pump into compliance with the provisions of §60.482-2a of this part.

§60.5430

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor or pump cylinder from the crankcase.

19.1.6. API Request: Stringency of Leak Definition in Subpart OOOO

Due to all the issues raised above, API is requesting that EPA reconsider its proposed alteration of the equipment leaks program for natural gas processing plants. If EPA demonstrates that tighter VOC emission control is justified, we offer the below elements as an alternative program. We believe that the alternate program provides for real emissions reductions in a cost-effective manner.

- a) Set up an LDAR program that requires on-going quarterly monitoring for valves (no skip periods allowed), in lieu of going down to a 500 ppm leak definition for valves. This approach retains the current Subpart KKK leak definition of 10,000 ppm, with its associated repair intervals.
- b) For initial compliance purposes, valve monitoring would be undertaken monthly during the first quarter of becoming subject to this program. Following that, monitoring would continue on a quarterly basis. New and repaired components would be monitored on the quarterly basis rather than having to be monitored monthly.
- c) Facilities would be required to establish internal programs to identify valves that are 'chronic leakers' (valves that leak above 10,000 ppm during three of the four quarters in a year). These valves would be placed on a 'chronic leakers' list and would be designated for refurbishment and/or replacement during the next process unit shutdown.
- d) No new LDAR program for connectors would be imposed, as such a program is not cost effective. API recommends that connectors in gas/vapor service and in light liquid service be subject to the monitoring and leak definition provisions in §60.482-8a.
- e) Retain the 10,000 ppm leak definition for pumps because EPA has not demonstrated the proposed 2000 ppm leak definition as BSER. API recommends that if EPA wishes to evaluate lowering the pump leak definition it might consider the possibility of establishing a 5000 ppm leak definition, after notice and comment rulemaking, if the proposed leak definition is justified as BSER.

- f) Incorporate into the final Subpart OOOO a provision similar to §60.482-3a(j) of Subpart VVa relative to reciprocating pumps. A definition of “distance piece” that is similar to the one in Subpart VVa needs to be added in the final Subpart OOOO, §60.5430. The proposed regulatory language is shown in Section 19.1.5 above.

19.2. Subpart OOOO – Alternative Work Practice

EPA has evaluated several options for an LDAR program for gas processing plants using optical gas imaging (OGI). The options evaluated included: (a) OGI monitoring with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at §60.18(g)); (b) monthly OGI without an annual Method 21 check; and (c) Similar to (b) only annual rather than monthly OGI.

19.2.1. Response to EPA's Request for Comments

On page 52755 of the preamble EPA states, “We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies.” EPA recognizes that analysis they have conducted previously have determined that the VOC reduction achieved by bi-monthly OGI monitoring provides an equivalent, or better, VOC emissions reduction when compared to a quarterly M21 based program with a leak definition of 500 ppm. The key to the OGI based monitoring is the ability to conduct more frequent monitoring, with identification and repair of leaking components that contribute a high percentage of the total mass emissions.

The AWP at §60.18(g) specifies the required monitoring frequency and sensitivity threshold for OGI instruments that would ensure the equivalency of emissions control. The analysis that supported the promulgation of §60.18(g) confirmed the specified OGI program would provide equivalent emissions control to a VVa type program without any associated M21 screening. None-the-less the promulgated AWP includes a requirement for annual M21 monitoring.

Requiring an annual leak survey using M21 makes this AWP impractical, burdensome, and ineffective. It actually negates the flexibility that would otherwise be afforded by allowing an OGI only AWP for Subpart OOOO compliance.

Implementing an OGI only AWP is consistent with the monitoring requirements for the mandatory GHG reporting under 40 CFR Part 98 Subpart W. Hence using such an approach to satisfy both LDAR and GHG monitoring would improve its effectiveness and reduce duplicative and redundant requirements for facilities.

19.2.2. API's Previous Recommendations on AWP

API staff and member companies met with Office of Air Quality, Planning and Standards (OAQPS) staff on August 18, 2011 to address the issues and barriers to the implementation of the AWP as noted in Section 19.2.1 above. In response to EPA's request for comment on the potential applicability of an LDAR program that is based solely on OGI monitoring, we

would like to recap here API's major recommendations from the August 2011 meeting with OAQPS:

- a) API urged OAQPS to return to an OGI AWP without requiring an annual M21 survey, as analytical and field studies have been completed and all of them demonstrate AWP equivalency. Additional data will become available as to the effectiveness of the OGI AWP if the M21 requirement is removed and facilities then will start using it.
- b) API urged EPA to restore the 10% AWP Sensitivity Test Option. This option demonstrates high instrument sensitivity and eliminates the need for the burdensome "least-detectable-fraction" stream analyses.
- c) API requested that EPA clarify and modify the video recording requirements by amending rule language to clarify that video records will identify regulated equipment via a defined area grouping, not by a recording of each equipment component. EPA should also evaluate how the video data will be used and whether a complete video recording is really needed.
- d) API believes that OGI has the potential to be useful for difficult or unsafe to monitor components. However in order to make it work in the field, an extended or conditional repair schedule (first attempt at repair) is needed for difficult to access and unsafe to access components, with the final repair falling under the delay-of-repair provisions.
- e) API also urged EPA to work with stakeholders to develop an OGI Application Protocol for the AWP that is based on OGI techniques for LDAR programs. Guidance could include information on instrument sensitivity checks, techniques for process area monitoring, and emissions estimating from the optical imaging monitoring data.

19.2.3. API Requests

API requests that EPA make it possible to use an OGI only approach for LDAR by taking the following steps:

- a) Explicitly allow the use of OGI techniques without requiring an annual M21 survey.
- b) Implement the recommendations provided during the August 18, 2011 meeting with OAQPS, which are summarized in Section 19.2.2 above, to amend §60.18 and make it a real alternative work practice that could be widely implemented.
- c) As a fall back option, evaluate the use of a one-time, side-by-side survey using OGI and M21 as part of initial compliance for Subpart OOOO, with no further requirements for M21 annual surveys.

19.3. Subpart OOOO – Compressors at Natural Gas Processing Plants

As currently proposed, at natural gas processing plants, compressors are affected facilities under §60.5365(b) [centrifugal compressor affected facility] and §60.5365(c) [reciprocating affected facility], as well as §60.5365(f)(1) [compressor in VOC or wet gas service at onshore natural gas

processing plant]. Sections §60.5380 and §60.5385 outline the proposed dry seal and rod packing change-out requirements for centrifugal and reciprocating compressors, respectively. Even though the introductory language for VOC standards at natural gas processing plants in §60.5400 refers to compressors by stating, “(t)his section applies to each compressor in VOC service or in wet gas service...,” compressor control standards in Subpart VVa (§60.482-3a) was not referenced in §60.5400. Additionally, §60.5422, which addresses additional reporting requirements for gas processing plants, contains no VVa references for compressors. Thus, while compressors at natural gas processing plants are affected facilities under §60.5365(f)(1), there are no substantive control or reporting requirements that address VOC equipment leaks from such compressors.

To avoid compliance confusion, EPA should remove the reference to compressors at onshore natural gas processing plants from the VOC equipment leak provisions in the proposed rule, specifically, §§60.5365(f)(1) and 60.5400, and the definition of equipment in §60.5430.

Suggested Rule Text

§60.5365

(f) ~~Compressors and~~ Equipment (as defined in §60.5430) located at onshore natural gas processing plants.

~~(1) Each compressor in VOC service or in wet gas service is an affected facility.~~

~~(1)(2)~~ The group of all equipment, ~~except compressors~~, within a process unit is an affected facility.

~~(2)(3)~~ Addition or replacement of equipment, as defined in §60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

~~(3)(4)~~ Equipment (as defined in §60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in §60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart.

~~(4)(5)~~ Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) ~~and (f)(2)~~ of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

§60.5400

This section applies to ~~each compressor in VOC service or in wet gas service and~~ the group of all equipment (as defined in §60.5430), ~~except compressors~~, within a process unit.

19.4. Subpart OOOO – Applicability

API has concerns with several issues in the proposed rule that will determine whether and/or how the LDAR provisions would apply to certain natural gas processing plants, process units, equipment, or process streams. These issues are described below along with API's recommendations.

19.4.1. Definition of Natural Gas Processing Plant

Under the current definition in the proposed §60.5430, many very small remote sites without stable power supply would be defined as a natural gas processing plant, and thus subject to the LDAR requirements of the proposed rule. One example is the small sites in the production field that operate a single small JT unit. It is both technically and economically infeasible for such sites to comply with any LDAR requirements, especially the very stringent Subpart VVa requirements.

API requests that EPA address this issue by the following:

- (a) Modify the definition of natural gas processing plant by inserting the word "forced" before "extraction of natural gas liquids..."; and
- (b) Add a new definition of "forced extraction of natural gas liquids" that is essentially adopted from the Greenhouse Gas Mandatory Reporting Rule, 40CFR98, Subpart W (see 76 FR 56050).

Suggested Rule Text – one revised definition, one new definition:

§60.5430

Natural gas processing plant (gas plant) means any processing site engaged in the [forced](#) extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

[Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption \(lean oil\), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids or fuel treatment skids.](#)

19.4.2. Definition of in Wet Gas Service

Proposed §60.5430 defines "in wet gas service" based on whether a component is handling material that has not been through the extraction step in a gas plant. As a result, the proposed *equipment leak provisions would apply to all such components regardless of the quantity of VOC present*. In VOC service, on the other hand, while not defined in the proposal is indicated in §60.5400(f) to be based on the VOC content of the material handled

(i.e., ≥ 10 wt% VOC). Under the proposed language, then, the equipment leak requirements would apply to components in wet gas service regardless of the VOC content of that material. This follows the example set in Part 60 Subpart KKK. In the BID for Subpart KKK^{PP}, EPA explained the reason for applying the equipment leak requirements to all components in wet gas service is that it is cost effective since, unlike in refineries and chemical plants, there are a relatively large number of wet gas components **containing between 1 and 10% VOC**.

On pages 5-5 and 5-6 of the NSPS KKK BID EPA states:

Response: In setting the VOC concentration limit, EPA took into consideration the VOC content below which equipment leak controls may not be cost effective. In the case of synthetic organic chemical plants and petroleum refineries, the costs of controlling the small number of streams containing less than 10 weight percent VOC appeared to be unreasonable in light of the emission reduction potential. Therefore [*sic*], EPA considered 10 weight percent VOC appeared to be an appropriate VOC concentration limit for those standards. In contrast, gas processing plants can have a large number of components in streams containing between 1 weight percent and 10 weight percent VOC, and the cost effectiveness of controlling emissions from these components is reasonable. Thus, the lower VOC concentration limit appeared to be warranted as a way to cover these streams.

However, this argument is invalid since cost effectiveness is not a function of the number of components in the 1-10% VOC range. The same overall emission factor and cost is used (and incurred) for every component subject to monitoring. It is the potential VOC emission reduction that changes with the VOC concentration. Thus, the potential VOC emission reduction per dollar of cost from monitoring a component containing 10 percent VOC is one tenth the potential VOC reduction per dollar of cost from monitoring components containing 100% VOC.

EPA has concluded in establishing the criteria for a component in VOC service that it is not cost effective to monitor components containing <10% VOC. That conclusion is consistent with the conclusions reached in NSPS VV, VVa and other VOC regulations. Exactly the same logic applies to components handling wet gas that contains <10% VOC. In the Technical Support Document for this proposal EPA assumed 20% of the TOC found to be leaking is VOC and based its cost effectiveness analyses on this assumption. For wet gas components in the 1-10% VOC concentration range, the cost effectiveness is therefore between 20 and 2 times EPA's estimates, depending on the VOC concentration of each particular stream. Thus, as for components in VOC service, it is not cost effective (and not BSER) to apply the proposed equipment leak requirements to such components and the definition of "in wet gas service" should be deleted and the "in VOC service" criterion should be applied to all components in the source category.

However, if EPA intends to continue regulation of lower VOC content streams at natural gas processing plants, API recommends that the definition of "in wet gas service" be revised as

^{PP} EPA-450/3-82-024b, section 5.1.7

discussed in Sections 5.1.2 and 6.1.2 of the General Comments. As outlined in Section 5.1.2, "in wet gas service" would be defined to include field gas before extraction step that contain more than X% VOC by weight (API recommends X be equal to or greater than 5). While a revised definition of "in wet gas service" will still result in mandate of controls that are not cost-effective, the impact would be lessened because inert gas streams from enhanced recovery systems, coal-bed methane, and dry shale gas streams that contain little to no VOC would no longer require monitoring.

19.4.3. Definition of Equipment

As currently defined in §60.5430, "*Equipment* means each pump, pressure relief device, open-ended valve or line, valve, *compressor*, and flange or other connector that is in VOC *or wet gas service, and any device or system required by this subpart.*"

EPA should modify the definition as follows:

- (a) Remove the reference to compressor as compressors are affected facilities but have no associated requirements under the equipment leak provisions of Subpart OOOO. See the discussion in Section 19.3 above.
- (b) Delete applicability to components in wet gas service. If EPA insists on regulating low VOC content streams at gas processing plants, define "wet gas" such that the equipment leak provisions of this rule apply to only those field gas streams that contain 5% or more by weight of VOC. See the discussion in Section 19.4.2 above, as well as Sections 5.1.2 and 6.1.2 in the General Comments.
- (c) Clarify that the regulated components include *any device or system* required by *the equipment leak provisions* of this subpart. The proposed definition is taken from Part 60 Subpart KKK, because it only addresses VOC equipment leaks. Thus, "Any device or system required by [Subpart KKK]" is associated with controlling equipment leaks. Contrary to Subpart KKK, Subpart OOOO includes requirements for many types of affected facilities in addition to VOC equipment leaks. EPA should modify the definition of "equipment" to clarify that "any device or system required" is limited to "any device or system required by *the equipment leak provisions* of this subpart."

Suggested Rule Text:

§60.5430

Preferred Option:

Equipment means each pump, pressure relief device, open-ended valve or line, valve, ~~compressor~~, and flange or other connector that is in VOC service ~~or in wet gas service~~, and any device or system required by [the equipment leak provisions of](#) this subpart.

Alternative Option:

Equipment means each pump, pressure relief device, open-ended valve or line, valve, ~~compressor~~, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by [the equipment leak provisions of](#) this subpart.

19.4.4. Definition of Modification and Capital Expenditure

EPA should clarify the definition of *modification* as it pertains to applicable *equipment* in order to prevent minor additions/repairs from triggering Subpart OOOO requirements for existing KKK facilities, for consistency with Subpart KKK, and for clear expression of the indicated intent of this proposal.

Under the provisions of §60.14(e)(2), a change made to increase production is not a modification if the change does not require a capital expenditure. Capital expenditure is defined in §60.2 as “an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable ‘annual asset guideline repair allowance percentage’ specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.” The Part 60 equipment leak rules, including Part 60 Subpart KKK and this proposal (at §60.5365(f)(3)), further exclude process improvements made without a capital expenditure.

Part 60 Subpart VVa, whose requirements are applied under this proposal, extends the definition of capital expenditure as follows:

Capital expenditure means, in addition to the definition in §60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:

$$P = R \times A, \text{ where:}$$

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation:

$$Y = 1.0 - 0.575 \log X, \text{ where } X \text{ is } 2006 \text{ minus the year of construction; and}$$

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

Because capital expenditure is not defined in the proposal, the applicability provisions of Part 60 Subpart VVa are not referenced, and the applicable basic annual asset guideline repair allowance is not clearly indicated in the proposal or any of the referenced material, it is unclear how to determine if a modification associated with a production rate increase or process improvement has occurred.

API recommends that EPA add a definition of capital expenditure to Subpart OOOO §60.5430 that copies the definition from Subpart VVa, with modifications that are appropriate for natural gas processing plants and this rulemaking. Specifically, the modifications include: a) the year used in paragraph (2) above is, consistent with the Section 111 of the CAA, the year of the proposed Subpart OOOO, namely, 2011; and b) the value of B, as documented in §60.481 of Subpart VV for these facilities (identified as Subpart KKK facilities), is 4.5, if EPA incorporates in the final rule API's recommendations listed in Section 19.1.6 with regard to leak definition and the connector program. If EPA does not adopt those recommendations, then the value of B should be 12.5, the same as that for Subpart VVa.

Suggested Rule Text – new definition:

§60.5430

Preferred Option (if the leak definition remains at 10,000 ppm, and only AVO is required for connectors):

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:

$P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation:

$Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Alternative Option (if the leak definition is 500 ppm, or there is a connector monitoring program required) The definition would be the same as above, except:

(3) The applicable basic annual asset guideline repair allowance, B, is 12.5.

19.5. Subpart OOOO – New Delay of Repair Option for On-line Equipment Repair Using Specialized Methods

There are multiple technical and logistical issues that impact the feasibility of online repair using specialized methods, such as repair of a valve by injecting packing via drill and tap.

According to §60.482–9(a) of subpart VV, delay of repair is allowed if repair is technically infeasible without a process unit shutdown, and §60.482–9(c) of subpart VV allows delay of repair of valves if emissions associated with immediate repair would exceed continued emissions from the leak.

EPA has not demonstrated that use of specialized on-line repair methods is cost effective, particularly at the proposed leak definitions of 500 ppm for valves and connectors, and that the emissions associated with such repair attempts would be lower than if repair was delayed. Unlike refineries and chemical plants that have ready access to specialized maintenance contractors, many natural gas processing plants have to mobilize specialized contractors from long distances in order to attempt on-line repairs. This results both in increased costs and additional emissions from transportation and other logistical activities. The additional emissions may be more than would result from continued leaking at a low concentration range between 500 – 10,000 ppm.

API recommends that EPA add an additional delay of repair provision for on-line repairs utilizing specialized methods. Such repairs may be technically feasible, but are not logistically or economically feasible to be performed repeatedly to below 500 ppm within very narrow time windows. Facilities should be allowed a maximum of 90 days to complete these specialized repair attempts. Allowing more time reduces the cost burden and minimizes travel-associated emissions by enabling the repair of multiple components during fewer contractor site visits.

Suggested Rule Text:

§60.5401

* * * * *

(h) In addition to the provisions of §60.482-9a, delay of repair for valves and connectors will be allowed if:

(1) Initial (within 5 days of the leak being detected) and follow-up (within 15 days of the leak being detected) repair attempts using routine methods have been completed and were unsuccessful and

(2) Further on-line repair attempts require the use of a specialized repair contractor, and

(3) Further specialized repair attempts are completed as soon as practicable, but not later than 90 days after the leak was detected. If a repair attempt using a specialized

[technique is unsuccessful, repair shall occur before the end of the next process unit shutdown or as otherwise allowed by §60.482-9a\(e\).](#)

[A specialized repair contractor provides repair services not available from the facility or contractor maintenance personnel who perform routine repairs of most facility equipment leaks. An example of a specialized repair contractor is a contractor who provides valve gland drill and tap services.](#)

19.6. Subpart OOOO – Work Practice Implementation

The date by which LDAR work practices must begin is unclear in NSPS rules. At least a one year compliance period is needed for modified facilities to allow time to identify all covered components, tag them, gather and input all required information about each component into an LDAR database, develop testing routes, contract for the service, develop and arrange for required, timely leak repair and institute all of the procedures and recordkeeping associated with these programs. At new or reconstructed facilities, some of this work can be done prior to start-up, but not all of it. Furthermore, the compliance date for new and reconstructed facilities is unclear. For such facilities, we request the Agency clearly provide up to 180 days for sources to complete the initial round of monitoring.

In sum, **API requests** EPA allow at least a year for modified facilities, and 180 days for new or reconstructed facilities to implement work practice requirements.

19.7. Subpart OOOO – Equipment Upgrade Implementation

In some cases, facility upgrades will be needed at sources that become subject through modification. In particular, pump seals may require replacement or PSVs may need to be upgraded. Design, procurement and installation of such equipment takes considerable time and sources that come under these requirements through modification should be allowed up to three years to install such equipment upgrades.

API requests EPA allow three years for modified facilities to implement equipment upgrades as required.

19.8. Subpart OOOO – Exceptions in §60.5401 (d) and (e).

These two paragraphs exempt small gas processing plants and plants located in the Alaskan North Slope from routine monitoring requirements. However, there are several issues in these paragraphs that need to be addressed.

19.8.1. Typo in §60.5401(d)

There is an apparent typographical error in §60.5401(d), which reverses the small non-fractionating plant exemption in Subpart KKK. Subpart KKKK exempts any non-fractionating plant that does not have the design capacity to process 10 million scf/day or more of field gas.

19.8.2. Exemption from Reporting

Paragraph §60.5401(d) exempts certain components at small non-fractionating gas plants from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), and 60.5401(b)(1). Paragraph §60.5401(e) exempts the same group of components located in the Alaskan North Slope from the same monitoring requirements. API recommends that these components also be exempt from the reporting requirements by adding the following words at the end of these paragraphs: “*and the reporting requirements found in §§60.5420 and 60.5422.*”

19.8.3. Exemption for Connectors

As stated above, paragraphs (d) and (e) exempt the small non-fractionating plants and Alaskan North Slope plants from routine monitoring of pumps, valves and pressure relief devices (PRDs). Since Subpart KKK does not require routine monitoring of connectors, an exception for connector routine monitoring is not necessary in Subpart KKK. As discussed in Sections 19.1.2 and 19.1.6, API recommends that EPA only require auditory, visual and olfactory (AVO) inspections on connectors in the final rule. If EPA adopts API's recommendation, then no additional revision of §60.5401(d) and (e) is necessary. However, if EPA decides to adopt the Subpart VVa connector program requirements in the final rule, then API recommends that these two paragraphs be revised such that connectors at small non-fractionating plants and Alaskan North Slope plants are also exempt from routine monitoring, as pumps, valves and PRDs are.

19.9. Subpart OOOO – Clarifications Sought.

A couple of parts of the proposed rule language seem to either have typographical errors or statements that require clarification by EPA:

19.9.1. Pressure Relief Devices

It is unclear whether the stated alternate leak definition for PRDs in §60.5401(b)(2) is a typographical error. It states, “If an instrument reading of 5000 ppm or greater is measured, a leak is detected.” This seems to be in contrast with §60.5421(b)(2)(iv), where the language suggests a leak definition of 500 ppm.

19.9.2. Sampling Connection Systems

§60.5400(a) lists all the provisions in Subpart VVa with which an affected facility must comply, including the sampling connection systems requirements in §60.482-5a. However, §60.5401(c) exempts the affected sampling connection systems from the requirements in §60.482-5a. API requests that §60.482-5a be deleted from the list in §60.5400(a).

19.10. Subpart HH – Alternative Work Practice.

Concerns and recommendations described in Section 19.2 also apply to Subpart HH.

19.11. Subpart HH – Applicability.

19.11.1. Definition of Natural Gas Processing Plant

Concerns and recommendations described in Section 19.4.1 also apply to Subpart HH.

19.11.2. Definition of In Wet Gas Service

Concerns and recommendations described in Section 19.4.2 also apply to Subpart HH.

19.12. Subpart HH – Lower Leak Definition for Valves

§63.769 (c) states that,

“For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR Part 61, Subpart V, §§61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except for valves subject to §61.247–2(b) a leak is detected if an instrument reading of 500 ppm or greater is measured.”

This section of the rule may apply not only to large natural gas processing plants that are subject to Subpart KKK but also to smaller natural gas processing plant units where certain streams might be in VHAP service, which are currently not subject to Subpart KKK per the intent expressed in §63.769(b). Therefore, as documented in the discussion above (see Section 19.1), EPA's analysis overestimates the potential for emission reductions by lowering the leak definition for valves to 500 ppm. Therefore, the imposition of such a lower leak definition for valves at both new and existing natural gas processing plants is not warranted in terms of exposure reduction from plant operations. The risk benefit from the lower leak definition has not been demonstrated by EPA especially for smaller natural gas processing units.

API recommends that EPA retain the leak definitions for equipment leaks as currently promulgated in Subpart HH. This will prevent added compliance confusion and high costs to industry without demonstrated significant risk reductions.

19.13. Subpart HH – Extending Compliance Time

40 CFR 63 Subpart HH applies to both new and existing facilities. It is not feasible to expect existing facilities to be able to be in compliance instantaneously upon promulgation. For example, the leak definition for valves would be lowered from 10,000 ppm to 500 ppm. Upon promulgation of the final rule, it is expected that at an existing facility, a great number of valves which were previously not a leaker would suddenly become a leaker. Adequate supply of maintenance personnel and valve parts necessary to repair that many leakers within the time frame allowed in the rule is very questionable. In certain cases, the needed personnel and/or parts would simply not be available. If the rule provides a reasonable compliance time, the owner/operator of the facility would be able to plan and execute the leaker repair maintenance activities in a much more orderly fashion, and more importantly, in compliance with the rule. Our preference is to keep the 10,000 ppm leak definition. However, if the leak definition is to drop down to 500 ppm, then additional time to comply should be allowed as we recommended above for Subpart OOOO, namely, at least a year for existing facilities, and 180 days for new facilities to implement work practice requirements.

19.14. Subpart HH – Overlap with Subpart OOOO

Proposed §63.769(b) exempts ancillary equipment and compressors subject to Part 63 Subpart H and Part 60 Subpart KKK from the proposed §63.769(c) equipment leak requirements. This exemption should also apply to equipment and compressors that are subject to the new Part 60 Subpart OOOO, since otherwise duplicative and sometimes conflicting requirements would apply.

Suggested Rule Text

§63.769

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or the requirements specified in 40 CFR part 60, subparts KKK or OOOO.

20. GLYCOL DEHYDRATORS [NESHAP HH & HHH]

In both the Oil and Gas Production MACT (subpart HH) and the Natural Gas Production and Storage MACT (subpart HHH), EPA separated glycol dehydrators into two groups, or “subcategories.” While the “small dehydrator” and “large dehydrator” terminology is new in the proposed regulations, the concept and criteria defining these groups is present in the existing subparts HH and HHH. Table 20-1 shows the characteristics of each of these groups, as well as the current and proposed standards for each.

Table 20-1. Summary of Glycol Dehydrator Group Criteria and Emission Limitations

Subpart	Dehydrator Group	Characteristics of Group	Requirements	
			Current	Proposed
HH	Large	Flow rate ≥ 85,000 m ³ /day (3 million ft ³ /day) AND benzene emissions ≥ 0.9 Mg/yr (1 ton/yr)	Reduce HAP by 95% or reduce benzene emissions < 0.9 Mg/yr (1 tpy)	Reduce HAP by 95%
	Small	Flow rate < 85,000 m ³ /day (3 million ft ³ /day) OR benzene emissions < 0.9 Mg/yr (1 ton/yr)	NONE	Reduce BTEX emissions to a unit-specific emission limit calculated based on the dehydrator throughput and BTEX concentration at the inlet to the glycol dehydration unit
HHH	Large	Flow rate ≥ 283,000 m ³ /day (10 million ft ³ /day) AND benzene emissions ≥ 0.9 Mg/yr (1 ton/yr)	Reduce HAP by 95% or reduce benzene emissions < 0.9 Mg/yr (1 tpy)	Reduce HAP by 95%
	Small	Flow rate < 283,000 m ³ /day (10 million ft ³ /day) OR benzene emissions < 0.9 Mg/yr (1 ton/yr)	NONE	Reduce BTEX emissions to a unit-specific emission limit calculated based on the dehydrator throughput and BTEX concentration at the inlet to the glycol dehydration unit

As can be seen in Table 20-1, EPA proposed two significant changes to the glycol dehydrator provisions:

- (1) eliminate the alternative 0.9 Mg/yr benzene emission limitation for large dehydrators, and
- (2) propose standards for small dehydrators.

API disagrees with both these decisions and does not believe that EPA has adequately justified them.

20.1. Large Dehydrators – The 0.9 Mg/yr Benzene Alternative Emission Limitation Must Be Retained in both Subpart HH and Subpart HHH

As discussed above, the Oil and Gas Production MACT (Subpart HH) currently includes two compliance options for glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr (i.e., “large” dehydrators). These options are to reduce organic HAP emissions by 95% or to reduce benzene emissions to less than 0.9 Mg/yr. Similarly, the Natural Gas Transmission and Storage MACT (subpart HHH) requires glycol dehydrators with an actual annual average natural gas flow rate greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr to reduce HAP emissions by 95% or benzene emissions to less than 0.9 Mg/yr. EPA is proposing to eliminate the 0.9 Mg/yr benzene emissions compliance alternative for large dehydrators for both source categories.

Note that EPA decisions related to the 0.9 Mg/yr benzene alternative for large dehydrators in both MACT standards are unrelated to the 0.9 Mg/yr benzene emission threshold used to differentiate between small and large dehydrators. API has comments on the emission limits proposed for small dehydrators, which are provided in Section 20.3. However, as will be evident in API's comments below, EPA must restore the 0.9 Mg/yr benzene emissions for large dehydrators independent of any decisions related to small dehydrators.

For both MACT standards, these decisions were proposed under the authority of CAA section 112(f)(2). Thus, these are “risk-based” decisions. As discussed in Section 12, we have numerous basic concerns with EPA's decision to make significant and substantive changes unilaterally to the residual risk procedure that has been established in accordance with CAA mandates, vetted with Congress, and ratified by precedent. Some of the primary areas of concern include consideration of risk from the total facility, consideration of risk across selected social, demographic, and economic groups within the population living near the facility, and consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard. In addition, API believes that several factors, including the following, result in overestimates of risk that are between 100 and 1000-fold higher than estimates using more central factors:

- Assuming that all members of the population are continuously exposed for their lifetimes,
- Failing to consider time-activity patterns,
- Using only high end URE for decision-making, and
- Using only ultra conservative URE from CalEPA in the absence of IRIS values.

More detail on API's concerns with these aspects is provided in Attachment N, which is incorporated in these comments by reference.

While API has the overarching concerns with EPA's risk assessment and methodologies mentioned above, the risk-related decisions for large glycol dehydrators are based on flawed analysis. The evidence provided by EPA to support these conclusions is incorrect, and the outcome is that EPA has no basis for removing the 0.9 Mg/yr benzene alternative for either subpart HH or subpart HHH. Further details are provided in Attachment O, which is incorporated in these comments by reference.

20.1.1. Oil and Gas Production MACT – Subpart HH

In EPA's analysis for subpart HH,^{QQ} there are two facilities with a cancer MIR greater than 100-in-1 million based on MACT allowable emissions. These facilities are the Hawkins Gas Plant in Hawkins, Texas and the Kathleen Tharp 2 facility in Huffman, Texas. Since EPA determined that these facilities had a cancer maximum individual risk (MIR) greater than 100-in-1 million based on MACT allowable emissions, EPA determined that the risks are unacceptable for the oil and gas production MACT category and additional regulation is needed. However, as will be shown below, the results are entirely incorrect due to fundamental errors in EPA's calculations of MACT allowable risk for these two facilities. In addition, even if the analysis had been correct, there are significant issues associated with the data for both of these facilities that are sufficient to invalidate the results and EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable.

Fundamental Errors in EPA's Analysis. As noted above, EPA identified two facilities with cancer MIRs greater than 100-in-1 million based on MACT allowable emission levels. However, examination of EPA's analysis shows that the results are entirely incorrect due to fundamental errors in EPA's calculations of MACT allowable risk. This caused the calculation of MACT allowable risk estimates that are orders of magnitude too high. Following are details of this error.

In the analysis of risk based on the MACT allowable emissions level, EPA assumes that glycol dehydrators which control benzene emissions to levels less than 0.9 Mg/yr could increase benzene emissions to 0.9 Mg/yr. The analysis assumes a linear relationship between benzene emissions and risk, so the risk due to the actual benzene emissions level was multiplied by the ratio of 0.9 Mg/yr divided by the actual emission level. For example, if the cancer MIR based on 0.45 Mg/yr of actual benzene emissions was 40-in-1 million, the cancer MIR based on the 0.9 Mg/yr benzene MACT allowable emissions level would be 80-in-1 million.

In their MACT allowable analysis, EPA used the incorrect actual emissions level to adjust the risk to a 0.9 Mg/yr basis. Specifically, for dehydrator DN0005 at the Hawkins Gas Plant, EPA used a benzene emission rate of 0.00004 tons/yr instead of the correct value of 0.01290

^{QQ} Memorandum. From Heather Brown, P.E., EC/R Incorporated and Lesley Stobert, EC/R Incorporated, to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT – MACT Allowable Emissions and Risks." July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0055)

tons/yr. This resulted in a multiplier of over 23,000 ($1 / 0.00004$) and a MIR of 400-in-1 million. The benzene emission rate for this point, as shown in the Appendix to EPA's Risk Assessment Document,^{RR} is 0.01290 tons/yr. This emission rate results in a MACT allowable multiplier over 300 times lower than the value used by EPA. Inserting the correct actual emissions number in EPA's analysis results in a MACT Allowable MIR of 3-in-1 million for the Hawkins Gas Plant.

A similar error occurs for the Kathleen Tharp2 facility. For dehydrator DN0001, the correct actual benzene emissions rate is 0.1140 tons/yr. However, EPA used an incorrect emission rate of 0.0001 tons/yr. Inserting the correct benzene rate in the analysis results in a MACT allowable MIR of 0.2-in-1 million for this facility. Details of the errors and API's corrections are provided in Attachment O, which is incorporated in these comments by reference.

After the MACT allowable MIRs are corrected for these two facilities, the highest MACT allowable MIR is 50-in-1 million for the Seneca Resources Corporation facility in Ojai, CA. This is clearly at a level that EPA has never considered as unacceptable.

Major Issues in EPA's Data Set for Facilities Driving the Risk. The issues associated with the data for the two facilities with cancer MIRs greater than 100-in-1 million based on MACT allowable emissions are sufficient to invalidate the results and EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable. The highest risk facility, with a cancer MIR of 400-in-1 million based on MACT allowable emissions, is the Hawkins Gas Plant in Hawkins, Texas. A review of the background data in EPA's dataset for this facility has found significant errors. For example, the EPA data set includes data for eight dehydrators when in fact there are only three dehydrators at the plant. The Hawkins Gas Plant operates three glycol dehydrators, with a fourth dehydrator on site but has been shut down for more than 10 years. In addition, one of these dehydrators (DehyRod) falls into EPA's definition of "small dehydrator" and should not have been considered in the large dehydrator analysis, as its throughput is less than 60,000 m³/day. For the past 10 or more years, only emissions data for the three operating glycol dehydrators has been submitted to the TCEQ for the annual emissions inventory.

There are no emissions during normal operation of these three dehydrators as the still vent vapors are routed through a vapor recovery compressor (VRC) and back into the process. There is no emissions point. However, as a backup for times when the vapor recovery compressor is down, dehydrator still vent emissions are routed first through a BTEX condenser, then to the low pressure flare. Emissions only occur during VRC downtime which is reported to the TCEQ each year in the emissions inventory. The table below lists the annual emissions reported to the TCEQ for the emissions inventory for 2005-2009.

^{RR} "Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories." EPA, Office of Air Quality Planning and Standards, Office of Air and Radiation. July 2011. (Docket Item EPA-HQ-OAR-2010-0505-0032)

Table 20-2. Hawkins Plant Dehydrator Emissions

Hawkins Plant Dehy	Annual Emissions (tons/yr)									
	2005		2006		2007		2008		2009	
	VOC	BTEX	VOC	BTEX	VOC	BTEX	VOC	BTEX	VOC	BTEX
DehyHP	0.05	0.009	0.15	NA	0.024	NA	0.01	NA	0.004	NA
Dehy80	0.86	0.03	0.027	NA	0.21	NA	0.045	NA	0.023	NA
DehyRod	0.005	0.005	0.33	NA	0.057	NA	0.003	NA	0.004	NA

The facility with the second highest MACT Allowable risk (200-in-1 million) is the Kathleen Tharp 2 facility in Huffman, Texas. API has confirmed with the Texas Commission on Environmental Quality (TCEQ) that this facility does not have a Title V permit and is not a major source of HAP.^{SS} API has also obtained documentation that a Form PI-8 has been filed for this facility. A Form PI-8 certifies emissions below the minor source limit of 25 tons/yr VOC, and makes the certified emissions enforceable. Therefore, it should not be considered in this analysis.

Conclusion for Oil and Gas Production MACT. EPA must reverse its proposed decision to eliminate the 0.9 Mg/yr benzene compliance alternative in subpart HH for glycol dehydrators with actual annual average natural gas flow rates greater than or equal to 85,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr. The analysis that resulted in risks determined by EPA to be unacceptable, and the data used in the analysis, both have significant errors. Correction of these errors leads to risk estimates well within the ranges that EPA determines to be acceptable.

In the absence of an unacceptability risk determination, EPA cannot legitimately argue that removal of the 0.9 Mg/yr is a cost effective measure under the ample margin of safety decision. In the technical documentation estimating the impacts of RTR control options,^{TT} EPA estimated the cost effectiveness of removing the 0.9 Mg/yr benzene alternative was \$14,000/Mg HAP. This cost effectiveness, which is EPA's estimate, is at the high range of most past EPA MACT decisions. However, this EPA estimate is lacking and actually significantly underestimates the cost effectiveness. EPA's estimate takes full credit for a 95% reduction in HAP emissions. However, any large dehydrator that is currently complying with the 0.9 Mg/yr benzene limit utilizes some type of control device designed to reduce benzene emissions 0.9 Mg/yr. The benzene emission reduction needed to achieve 0.9 Mg/yr could be less than 95%. In such cases, it would only be appropriate to consider the incremental emission reduction obtained when additional control is installed.

^{SS} Personal Communication. Norwood, P., ERM, and Moore, S., TCEQ Houston Regional Office. October 13, 2011.

^{TT} Memorandum. From Heather Brown, P.E., and Lesley Stobert, EC/R Inc. to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Impacts for Control Options for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage Categories as a Result of the Residual Risk and Technology Review." August 19, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0077)

For example, consider a large dehydrator with uncontrolled benzene emissions of 3 Mg/yr. In order to comply with the 0.9 Mg/yr benzene limitation, a condenser or other control device could be installed that achieves approximately 70% reduction. If the 0.9 Mg/yr benzene emission limitation is removed, the facility would need to install an additional control device to meet the 95% requirement (which would require that emissions be reduced to 0.15 Mg/yr). However, EPA must claim only the incremental reduction (0.75 Mg/yr) and not the total 95% reduction (2.85 Mg/yr). This would increase the calculated cost per ton 4 fold.

In fact, EPA has already estimated the cost effectiveness for this incremental control. The cost effectiveness that is more appropriate for this option is \$167,200/Mg HAP, which is the cost effectiveness estimated by EPA for the addition of a second control device (76 FR 52768). Without a doubt, this cost effectiveness is not reasonable.

In view of these clear facts, EPA must repeal its proposed conclusion under section 112(f)(2) of the CAA to remove the 0.9 Mg/yr benzene compliance alternative for subpart HH. The corrected analysis does not result in an unacceptable risk and the available information cannot support a conclusion that this action is necessary to achieve an ample margin of safety.

Further, EPA has no basis under any other CAA authority to remove the 0.9 Mg/yr benzene alternative for large dehydrators at oil and gas production facilities. Under 112(d)(6), EPA did not identify any developments in practices, processes, or control technologies to further reduce emissions from large dehydrators. EPA already established MACT floors for glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time. Further, since large dehydrators are subject to standards under the existing subpart HH, they do not represent an "unregulated" emission sources that EPA can address under section 112(d)(2) and (3). Finally, as noted above, EPA estimated that the cost effectiveness of additional controls to be \$167,200/Mg HAP, which cannot be justified as reasonable under any circumstance.

20.1.2. Natural Gas Transmission and Storage MACT – Subpart HHH

For the Natural Gas Transmission and Storage source category, EPA found that risks from sources subpart to subpart HHH were acceptable (even when considering MACT allowable emissions). In the second step of the risk decision, EPA then proposed to eliminate the 0.9 Mg/yr benzene compliance alternative as part of their ample margin of safety determination.

While an ample margin of safety decision can consider numerous factors, EPA bases the decision to eliminate the 0.9 Mg/yr benzene emission limitation for subpart HHH on two basic factors: (1) it would reduce the cancer MIR from 90-in-1 million to 20-in-1 million, and (2) the cost effectiveness to comply with this option is reasonable. As will be demonstrated below, both of these conclusions are erroneous.

Removal of 0.9 Mg/yr Benzene Alternative Does Not Reduce Risk. EPA indicates that removal of the 0.9 Mg/yr benzene compliance alternative for glycol dehydrators with actual

annual average natural gas flow rates greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr would reduce the cancer MIR for the source category from 90-in-1 million to 20-in-1 million. However, this assertion is entirely incorrect as EPA's own technical analysis indicates that removal of the 0.9 Mg/yr benzene alternative would have NO effect on the MIR.

To summarize, EPA separates dehydrators into two groups, or subcategories for the natural gas transmission and storage source category:

- 1) Dehydrators with an actual annual average natural gas flow rate greater than or equal to 283,000 m³/day and actual average benzene emissions greater than or equal to 0.9 Mg/yr (i.e., "large" dehydrators), and
- 2) Dehydrators with an actual annual average natural gas flow rate greater less than 283,000 m³/day or actual average benzene emissions less than 0.9 Mg/yr (i.e., "small" dehydrators).

Large dehydrators in the first group are subject to the current standards, which require that organic reduce HAP emissions be reduced by 95% or benzene emissions reduced to less than 0.9 Mg/yr. Small dehydrators in the second group are not subject to standards in the current rule.

EPA's analysis shows that the dehydrators causing the 90-in-1 million MIR are in the second small dehydrator category, which means they are not even subject to the 0.9 Mg/yr benzene alternative. Therefore, removing it will have **NO** impact on these highest MIRs. This is clearly stated in a technical memorandum prepared by EPA's contractor which shows the MIR for the source category unchanged (90-in-1 million) without the 0.9 Mg/yr benzene alternative.^{UU}

EPA's Cost Analysis is Severely Flawed. Second, EPA concludes that the cost effectiveness of the proposed removal of the 0.9 Mg/yr benzene compliance alternative for natural gas transmission and storage facilities is reasonable. However, the costs estimates used by EPA in the ample margin of safety determination are inadequate. EPA did conduct any analysis using actual data. Rather, EPA used costs estimated for small dehydrators and rashly made general assumptions to estimate an upper-end cost effectiveness for removing the 0.9 Mg/yr benzene alternative limit for large dehydrators at natural gas transmission and storage facilities.

Specifically, EPA based their cost "analysis" on the following points.

"Although control methodologies are similar for large and small dehydrators, we expect that the costs for controls on large units could be as much as twice as high as for small units because of the large gas flow being processed." (76 FR 52783).

^{UU} Memorandum. From Heather Brown, P.E., and Lesley Stobert, EC/R Inc. to Bruce Moore, EPA/OAQPS/SPPD/FIG. "Impacts for Control Options for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage Categories as a Result of the Residual Risk and Technology Review." August 19, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0077)

API agrees that flow rates for the large dehydrators would, in general, be higher than those for small dehydrators. API also agrees that the costs for these controllers would be higher, although EPA has provided no support for the argument that the upper range of this cost would be twice that of controls for small dehydrators.

“However, we also expect that the amount of HAP emission reduction for the large dehydrators, in general, to be as much as, or more than, the amount achieved by small dehydrators.” (76 FR 52783).

EPA provides no data to support this claim. API disagrees with this statement, and believes that in general, the emission reductions for dehydrators forced to switch from the 0.9 Mg/yr benzene alternative to 95% control would be considerably less than those achieved by small dehydrators. The cost effectiveness calculated for small dehydrators is based on a 95% reduction from an uncontrolled baseline level. If a large dehydrator has installed controls to meet the 0.9 Mg/yr alternative benzene limitation, the cost effectiveness must be based on the incremental reduction between the existing controls and 95%. EPA has provided no evidence that these incremental reductions would be greater than or equal to the 95% reductions that would be achieved for smaller dehydrators.

This does not even approach a credible analysis that should be considered for any EPA decision, much less a major decision to eliminate the 0.9 Mg/yr benzene alternative emission limitation.

Conclusion for Natural Gas Transmission and Storage MACT. The rationale used by EPA in the preamble to support the removal of the 0.9 Mg/yr compliance alternative for dehydrators at natural gas transmission and storage facilities under 112(f)(2) of the CAA is not supported by any of the background technical documentation and analyses. The high risks that EPA claims will be reduced by removal of the 0.9 Mg/yr benzene alternative are, by EPA's own estimation, dehydrators that are not even subject to the current 0.9 Mg/yr benzene alternative in the regulation. Further, the cost analysis relied upon by EPA to conclude that controls for this option are cost effective does not even pass a “straight-face” test. Therefore, EPA has demonstrated no valid rationale for removing this 0.9 Mg/yr benzene alternative at natural gas transmission and storage facilities. Since there is no justification for removing the 0.9 Mg/yr benzene alternative, EPA must maintain it in subpart HHH.

Further, EPA has no basis under any other CAA authority to remove the 0.9 Mg/yr benzene alternative for large dehydrators at natural gas transmission and storage facilities. Under 112(d)(6), EPA did not identify any developments in practices, processes, or control technologies to further reduce emissions from large dehydrators. EPA already established MACT floors for glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time. Further, since large dehydrators are subject to standards under the existing subpart HHH, they do not represent an “unregulated” emission sources that EPA can address under section 112(d)(2) and (3).

20.2. 90 Day Compliance Time For Large Dehydrators Is Insufficient If The 0.9 Mg/Yr Benzene Compliance Option Is Removed

The proposed regulation only allows a 90 day compliance period for large dehydrators that are currently complying with the 0.9 Mg/yr benzene alternative emission limitation. As discussed above in Section 20.1, EPA's rationale for eliminating the 0.9 Mg/yr benzene limitation is severely flawed. We expect that EPA will restore the 0.9 Mg/yr benzene limitation after consideration of these comments. However, in the unlikely case that EPA does not restore this alternative limitations, EPA must extend the compliance date to the same three year period proposed for newly regulated small dehydrators and storage vessels without the potential for flash emissions.

In the preamble, EPA states the following:

“Without the compliance alternative, affected glycol dehydrators (i.e., those units with annual average benzene emissions of 0.9 Mg/yr or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary.” (76 FR 52783)

EPA's assertion that existing controls used to comply with the 0.9 Mg/yr benzene alternative emission limitation could achieve compliance with the 95% requirement “in most cases” does not appear to be supported by information or analysis. This clearly was a factor in EPA's decision to only allow 90 days for compliance. However, basic logic would not lead to a conclusion that existing control devices installed to meet the 0.9 Mg/yr benzene limit could also achieve 95% BTEX control. It is logical to assume that owners and operators complying with the 0.9 Mg/yr benzene limitation selected this alternative because it was less costly and less burdensome than complying with the 95% HAP reduction standard. As EPA is aware, the composition of natural gas processed in dehydrators across the county varies considerably. For situations with lower benzene content, the 0.9 Mg/yr emission limitation could be met using controls that achieve less than 95% reduction. While these units are in full compliance with the 0.9 Mg/yr limit, additional controls would need to be added to comply with the 95% standard. The process for evaluating, identifying, selecting, and installing these controls would be the same for these situations as for a small dehydrator previously not subject to any standards. Therefore, the time frame for compliance should also be the same – 3 years.

20.3. Small Dehydrators – The BTEX Emission Limit Is Not Necessary And Should Be Removed

In the preamble for the proposed rule (76 FR 52746), EPA identifies small dehydrators as an unregulated emission source. Therefore, under the authority of section 112(d)(2) and (3), EPA proposed to establish emission standards for small dehydrators in both subpart HH and subpart HHH.

EPA already established MACT floors for glycol dehydrators and promulgated regulatory decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days). Therefore, EPA does not have authority to revisit the floor at this time and should not promulgate any standards for small dehydrators.

Further, as will be demonstrated below, small dehydrators are already subject to emission standards under the current regulations and therefore, cannot be classified as unregulated emission sources. Given the fact that the 0.9 Mg/yr benzene level serves as both an emission limitation and a threshold separating the two groups of dehydrators, the reality that small dehydrators are subject to standards is not readily apparent. API will demonstrate that this is, in fact, consistent with the original regulatory determinations in 1998/1999.

It is very clear from the language of subparts HH and HHH that dehydrators of any size are subject to the rules:

Subpart HH: §63.760

* * * * *

(b)(1) For major sources, the affected source shall comprise each emission point located at a facility that meets the criteria specified in paragraph (a) of this section and listed in paragraphs (b)(1)(i) through (b)(1)(iv) of this section.

(i) Each glycol dehydration unit;

Subpart HHH: §63.1270

* * * * *

(b) The affected source is each glycol dehydration unit.

Small dehydrators are clearly subject to rules of general applicability, such as reporting and recordkeeping. They are subject to the general duty in §63.6(e) (as it was in effect at the time the rule was published) relating to good operation and maintenance requirements, effectively imposing a work practice standard on these units, even if no emissions standard actually applies. Section 63.762 also imposes similar work practice requirements on all affected facilities. But, in effect, subparts HH and HHH do impose emissions limitations on all dehydrators.

As shown in Table 20-1, the 0.9 Mg/yr benzene level appears both as a criterion distinguishing small and large dehydrators and as an emission limit for large dehydrators. The effect is that the current regulation actually imposes emission limitations on all dehydrators. This is particularly clear from the fact that small dehydrators must document that the control requirements do not apply to a dehydrator by, in effect, performing an emissions analysis.

This fact was extremely obvious in the original proposal, where EPA stated the following:

“An owner or operator must be able to demonstrate that exemption from control criteria are met when controls are not applied. For example, owners or operators of glycol dehydration units that do not install air emission controls because the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy) must be able to demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy).” (63 FR 6295, February 6, 1998)

In response to both subparts HH and HHH, many owners and operators installed controls or made process improvements to reduce benzene emissions to less than 0.9 Mg/yr benzene. In some of these situations, the dehydrators are subject to the control device, testing, and monitoring provisions in

subpart HH or HHH, while in other situations owners and operators obtained permit conditions to limit their benzene emissions below 0.9 Mg/yr. In all these cases, the benzene emissions were reduced to achieve a level below 0.9 Mg/yr. For example, an API member company operates a glycol dehydrator at a major source production facility in Texas with an actual average annual natural gas flow rate of 570,000 SCMD (20 MMSCFD). Emissions are reduced by a condenser, followed by a flare. The facility complies with the provisions in §63.765(b)(1)(ii) to reduce benzene emissions to less than 0.9 Mg/yr. The facility has a state federally enforceable permit condition limiting the benzene emissions less than 0.9 Mg/yr. The facility also complies with the associated testing, monitoring, recordkeeping, and reporting requirements under subpart HH. Another example is an API member company glycol dehydrator at a production facility in Colorado. Emissions are reduced by a condenser, followed by a flare. The facility complies with the provisions in §63.765(b)(1)(ii) to reduce benzene emissions to less than 0.9 Mg/yr. The facility has a state federally enforceable permit condition limiting the benzene emissions less than 0.9 Mg/yr. The facility also complies with the associated testing, monitoring, recordkeeping, and reporting requirements under subpart HH.

In many situations, the benzene emissions without any controls may be less than 0.9 Mg/yr. For example, an API member facility in the Barnett Shale contains several dehydrators that treat a very dry east Barnett Shale gas with a VOC content of around 0.25 mole% (0.63 weight %) and a benzene content of around 10 ppm. The uncontrolled emissions from each of these units, which process over 500,000 SCMD (18 MMSCF), are only around 0.13 tpy benzene and 0.36 tpy total BTEX. As described above in the excerpt from the 1998 preamble, in such situations owners and operators would be required to “*demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy).*”

Therefore, in reality, the 0.9 Mg/yr represents an emission limit to which every facility is subject, thus meaning there are no “unregulated” dehydrators.

In the original proposal and promulgation of subparts HH and HHH (February 5, 1998 and June 17, 1999, respectively), EPA was not consistent in the discussion of subcategorization and MACT floors for glycol dehydrator vents. In the preamble for the promulgated rule (June 17, 1999), EPA states the following:

To determine the MACT floor, the EPA divided glycol dehydration units into two sizes: (1) small glycol dehydration units with actual annual average natural gas throughputs less than 85 thousand m³/day or with actual average benzene emissions less than 0.90 Mg/yr, and (2) large glycol dehydration units with actual annual average natural gas throughputs equal to or greater than 85 thousand m³/day or with actual average benzene emissions equal to or greater than 0.90 Mg/yr. For small glycol dehydration units, the EPA determined that the MACT floor was no control and that it was not cost effective to select a regulatory alternative beyond the floor. For large glycol dehydration units, the EPA reviewed the information that was available to develop a MACT floor (a detailed discussion of the development of the MACT floor can be found in the docket, Air Docket A-94-04). (64 FR 32613)

However, examination of the MACT floor technical memorandum^{vv} does not indicate that there was any consideration given to different sizes of dehydration units. In fact, the memorandum states the following:

Therefore, the determination of the MACT floor level of control for glycol dehydration units in this analysis is based on the data reported for all glycol dehydration units from the company responses to the four Air Emission Survey Questionnaires.” (p. 6).

Similarly, the proposed preamble made it clear that the MACT floor determination was not limited to large dehydrators –

The MACT floor for all process vents at glycol dehydration units . . . (63 FR 6304, underline added).

Further, while EPA's terminology was inconsistent, EPA recognized that the proposed and promulgated standards did subject all glycol dehydrators to standards. The 0.9 Mg/yr threshold/emission limit recognized and rewarded compliance via more environmentally friendly and cost effective process modifications and pollution prevention measures. However, it was clear that EPA was not totally exempting dehydrators below 0.9 Mg/yr benzene from the responsibility to maintain emissions below this level and demonstrate compliance with this alternative.

“For example, owners or operators of glycol dehydration units that do not install air emission controls because the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy) must be able to demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy). In general, the selected exemption criteria minimize the demonstration burden on owners and operators.” (63 FR 6295)

Therefore, EPA must consider the proposed limit for small glycol dehydrators as an adjustment to the existing limit under the authority of § 112(d)(6). As such, if EPA intends to promulgate these provisions, the Agency must first re-propose these provisions and justify the proposal as “necessary (taking into account developments in practices, processes, and control technologies).” This must include consideration of the naturally occurring variability in gas compositions, the variable throughput of dehydrators in this sector, and the resulting variation in dehydrator emissions and cost effectiveness of control.

EPA estimated the cost effectiveness of the proposed small dehydrator standards to be \$8,360/Mg HAP (76 FR 52768). While this EPA cost effectiveness is high, API maintains that this cost effectiveness analysis significantly underestimates the cost effectiveness of many dehydrators. This is primarily due to the fact that EPA did not account for the naturally occurring variability in HAP content in natural gas streams that would be covered by the proposed small dehydrator standards. Table 20-3 was generated from GRI-GLYCalc runs using a range of dehydrator operating throughputs and actual gas compositions (furnished by API member companies); and EPA's

^{vv} Memorandum. From Graham Fitzsimons and George Viconovic, EC/R Inc. to Martha Smith, EPA/WCPG. “Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category.” September 23, 1997. (Docket A-94-04, Item Number II-A-7)

annualized cost of control for dehydrators from Table 3-7 of the proposal RIA.^{ww} Unless noted, these examples reflect actual dehydrators in operation with their actual throughputs and gas compositions. More detail on these calculations is provided in Attachment P, which is incorporated in these comments by reference.

Table 20-3. Cost Effectiveness for Compliance with Proposed Small Dehydrator Emission Limitation at Oil and Gas Production Facilities

Facility Name	Inlet BTEX Content ppmv (Ci, BTEX)	Throughput SCMD	Uncontrolled BTEX Emissions (tons/yr)	Annualized Control Cost ¹	Control % to meet proposed equation (BTEX)	HAPS \$/Ton ²	BTEX \$/Ton ²
N. San Juan Basin Gas Treating and Compression Facility Dehy #1	0.9	2,406,935	0.93	\$30,409	94.0%	\$34,322	\$34,605
N. San Juan Basin Comp. Station M Dehy #1	1	849,506	0.77	\$30,409	97.1%	\$40,449	\$40,749
N. San Juan Basin Comp. Station WP Dehy	0	56,634	0	\$30,409	Undefined	\$152,045,000	Undefined
N. San Juan Basin Comp. Station WP Dehy - 2 Test	1	56,634	0.014	\$30,409	89.8%	\$2,318,324	\$2,350,522
N. San Juan Basin Comp. Station Q Dehy	16	424,753	1.6	\$30,409	89.2%	\$20,363	\$20,907
Barnett Shale Comp. Station Dehy - uncontrolled	12	580,213	1.2	\$30,409	85.2%	\$29,333	\$29,435
Barnett Shale Comp. Station Dehy - flash tank & condenser	12	580,213	1.0	\$30,409	82.3%	\$36,323	\$36,470
Arkoma Basin Gas Treating and Compression Facility SB Dehy	0	849,506	0	\$30,409	Undefined	Undefined	Undefined
Haynesville Shale Generic Dehydrator	77	212,377	1.8	\$30,409	76.5%	\$21,225	\$22,079
GGRB Basin Generic Well Site Dehy	404	42,475	4.9	\$30,409	91.0%	\$6,638	\$6,779
GGRB Basin Generic Well Site Dehy	404	28,316	3.286	\$30,409	91.0%	\$9,956	\$10,169
GGRB Basin Generic Well Site Dehy	404	14,158	1.643	\$30,409	91.0%	\$19,913	\$20,337
GGRB Basin Generic Well Site Dehy	404	5,663	0.6572	\$30,409	91.0%	\$49,782	\$50,843

¹Annualized Cost from page 3-26; Table 3-7 of RIA; with control % above ~20% the only viable option is to use a combustion device which is the basis for the Table 3-7 cost. Hence, the control cost does not go down with incrementally lower control %.

²For sites with no BTEX and undefined BTEX control % the control cost uses total emissions for species present.

As can be seen in Table 20-3, the cost effectiveness at the small dehydrator threshold ranges from \$152,000,000/ton-HAP to \$6,638/ton-HAP with most of the costs evaluated being substantially

^{ww} Regulatory Impact Analysis. Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry – U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711. July 2011. (Docket Item EPA-HQ-OAR-2010-0505-0075)

greater than EPA's estimate. These unreasonable costs occur for low BTEX content (San Juan Basin Coal Bed Methane) gasses regardless of throughput; moderate BTEX content (Haynesville shale) gasses with relatively high throughputs; and high BTEX content (Green River Basin Tight Sand) gasses with low throughputs (which are common in the Green River Basin). Obviously most of the illustrated control costs far exceed any reasonableness test and EPA cannot possibly justify the proposed requirements as a beyond the floor option with knowledge of these values. The situation for dehydrators in service for gas streams without any BTEX content (at a detection limit of 1 ppmv) becomes even more untenable and unreasonable. As defined in the proposed rule, these dehydrators would be classified as "small" and subject to application of "Equation 1" to determine allowable emissions. Application of "Equation 1" results in zero allowable emissions of BTEX. With the likely prospect of BTEX at some concentration lower than normal gas analysis detection limits this outcome essentially imposes 100% control requirements on dehydrators with almost zero potential for HAP emissions and almost infinite control costs. Obviously this is an unreasonable and likely technically unachievable requirement and must be corrected.

In conclusion, both subpart HH and subpart HHH, as currently promulgated, impose emission limitations on all glycol dehydrators. Therefore, these small dehydrators cannot be considered unregulated sources and EPA does not need to develop emission standards for the small dehydrators under CAA section 112(d)(2) and (3). In fact, since EPA already established MACT floors for all glycol dehydrators and promulgated these decisions on June 17, 1999 (64 FR 32610), and the rule was not challenged within the statutory period (90 days), EPA does not have authority to revisit the floor determinations at this time. EPA's proposed scheme for regulation of "small" dehydrators requires control on all dehydrators regardless of emissions or potential for emissions and results in completely unreasonable control costs for a wide range of gas compositions and throughputs. Further, as shown above, if EPA elects to move forward to propose separate standards for small dehydrators, such standards must be shown to be "necessary" in light of the factors specified in § 112(d)(6).

20.4. If EPA Moves Forward With Standards for Small Dehydrators, They Must Account for Fundamental Differences in Naturally Occurring Inlet Gas Concentrations and Dehydrator Design

As noted above, API does not believe that a separate standard is justified for small dehydrators. However, if EPA decides to move forward with standards for small dehydrators, they must not promulgate the proposed standards, as they are not technically and legally sound.

Subpart HH Proposed Equation 1 Would Require Over 90% Of The "Best Performing" Dehydrators To Install Additional Control. The severe flaws in EPA's small dehydrator floor analysis, derived equation 1, and control approach to calculate dehydrator-specific BTEX emission limitations are clearly illustrated by the application of Equation 1 to the 11 dehydrator units used by EPA for the MACT floor analysis for subpart HH. Table 20-4 illustrates the flawed construct by applying the proposed equation for subpart HH to the specific dehydrators making up the "top 12%" in EPA's MACT floor dataset.

Table 20-4. Application of Subpart HH Proposed Equation 1 for Small Dehydrators to MACT Floor Oil and Natural Gas Production Small Dehydrators

Unit ID No.	Legacy Docket A-94-04, Docket ID No.	No of Units	Control at Baseline?	BTEX Inlet Conc (ppmv)	Throughput (SCMD) Per Dehy Unit	BTEX Emissions at Baseline (Mg/yr)	Equation 1 Allowable BTEX Emission (Mg/yr)	Control % to meet proposed equation
A	II-D-10, pg 55	1	Y	116	17,556	0.0036	0.0477	n/a
B	II-D-09, pg 182	1	N	69	566,338	0.9979	0.9157	8.2%
C	II-D-19, pg 73	5	Y	60	45,307	0.0762	0.0637	16.4%
D	II-D-19, pg 21	1	N	140	99,109	0.5443	0.3251	40.3%
E	II-D-10, pg 115	1	N	39	42,475	0.0907	0.0388	57.2%
F	II-D-19, pg 41	1	N	308	29,450	0.8165	0.2125	74.0%
G	II-D-19, pg 39	1	N	5	45,307	0.0181	0.0053	70.7%

As can be seen in Table 20-4, only one of the 11 dehydrators that were used to calculate the MACT floor for small dehydrators in the oil and natural gas production source category can meet the proposed standard without the installation of additional controls. This would mean that the equation represents the average emission limitation achieved by best performing 1% of the dehydrators, not the best performing 12%. This obviously does not represent a legitimate MACT floor. Rather, the equations represent a beyond-the-floor level of control that EPA has not contemplated nor justified.

Proposed Small Dehydrator Equations Are Only Sensitive to BTEX Inlet Concentration. API believes the absurd results from application of the proposed Equation 1 to small dehydrators are an outcome of the floor analysis EPA conducted and erroneous conclusions reached that led to the Equation 1 construct. This construct is inherently flawed. Despite EPA’s inclusion of a throughput variable in the equations, the net effect is that the equations are only sensitive to the BTEX concentration (ppmv) in the inlet gas stream. Therefore, throughput or potential emissions have no effect on the control efficiencies required to meet the calculation emission limitation. This artifact is illustrated by the analysis summarized in Table 20-5, which clearly shows the Equation 1 outcome to be sensitive only to BTEX inlet concentration from the perspective of required control percentage. More details on this analysis are provided in Attachment Q.

Table 20-5. Illustration of Sensitivity of the Proposed Subpart HH Proposed Equation 1 for Small Dehydrators to Throughput Rates

Facility Name/Throughput (in MMSCFD)	Inlet BTEX Content ppmv (Ci, BTEX)	Throughput SCMD	Uncontrolled BTEX (tpy)	BTEX Emissions Allowed by Equation (tpy)	Control % to meet proposed equation (BTEX)	HAPS \$ ¹ /Ton	BTEX \$ ¹ /Ton
Coal Bed Methane - North San Juan Basin - SW Colorado							
N. San Juan Basin Gas Treating and Compression Facility Dehy 1 MMSCFD	0.9	28,317	0.011	0.0007	94.0%	\$2,913,934	\$2,940,424
N. San Juan Basin Gas Treating and Compression Facility Dehy 10 MMSCFD	0.9	283,169	0.11	0.0066	94.0%	\$291,656	\$294,042

N. San Juan Basin Gas Treating and Compression Facility Dehy 50 MMSCFD	0.9	1,415,844	0.55	0.033	94.0%	\$58,354	\$58,831
N. San Juan Basin Gas Treating and Compression Facility Dehy 100 MMSCFD ²	0.9	2,831,688	1.1	0.066	94.0%	\$29,174	\$29,416
Haynesville Shale - East Texas Basin - East Texas							
Haynesville Shale 1 MMSCFD	77	28,317	0.24	0.056	76.5%	\$159,187	\$165,555
Haynesville Shale 2 MMSCFD	77	56,634	0.48	0.11	76.5%	\$79,599	\$82,800
Haynesville Shale 4 MMSCFD	77	113,268	0.96	0.22	76.5%	\$39,799	\$41,400
Haynesville Shale 7.5 MMSCFD	77	212,377	1.8	0.42	76.5%	\$21,225	\$22,079
Haynesville Shale 8 MMSCFD (Large Dehy)	77	226,535	1.9	0.45	95.0%	\$16,030	\$16,675
Tight Sand Gas - Greater Green River Basin - SW Wyoming							
GGRB Basin Generic Well Site Dehy 0.2 MMSCFD	404	5,663	0.66	0.059	91.0%	\$49,782	\$50,843
GGRB Basin Generic Well Site Dehy 0.5 MMSCFD	404	14,158	1.6	0.15	91.0%	\$19,913	\$20,337
GGRB Basin Generic Well Site Dehy 1.0 MMSCFD	404	28,316	3.3	0.30	91.0%	\$9,956	\$10,169
GGRB Basin Generic Well Site Dehy 1.5 MMSCFD	404	42,475	4.9	0.44	91.0%	\$6,638	\$6,779
GGRB Basin Generic Well Site Dehy 2 MMSCFD	404	56,634	6.6	0.59	91.0%	\$4,978	\$5,084

¹Annualized Cost of \$30,409 from page 3-26; Table 3-7 of RIA.

²100 MMSCFD is about the maximum throughput limit for a dehydration system.

The Proposed Requirements Do Not Account For The Naturally Occurring Differences In HAP/BTEX In The Gas Being Treated In The Dehydrators. As shown above, the proposed small dehydrator equations are only sensitive to BTEX concentration. In addition, another fundamental problem with the proposed equations is the failure to account for situations where the very gas being treated contains very low levels of BTEX. Unlike processes where owners and operators have some ability to adjust raw materials to impact emissions, operators of dehydrators at oil and gas production and natural gas transmission and storage sites must deal with the naturally occurring composition of the natural gas. The proposed requirements would cover ALL dehydrators without regard to the inlet gas composition, throughput, or potential emissions. In other words, the propose approach for small dehydrators require controls in situations where the emissions rate is not a result of some kind of controllable circumstance, like emissions controls or affirmative choices as to raw materials.

Table 20-3 illustrated how this coverage of all dehydrators at oil and gas production sites results in unreasonable control scenarios. Further, Table 20-5 shows that the proposed subpart HH equation results in higher required control efficiencies for lower BTEX concentration streams. For example, the proposed rule would require a 94% reduction in BTEX emissions for a 10 MMSCFD dehydrator in the North San Juan Basin with inlet BTEX concentration of 0.9 ppmv and uncontrolled BTEX

emissions of 0.011 tpy. A similarly sized dehydrator in the Haynesville Shale with an inlet BTEX concentration over 85 times higher, and uncontrolled BTEX emissions over 4 times higher, would only be required to reduce BTEX emissions by 76.5%.

If EPA elects to pursue the development of standards for small dehydrators, API offers the following two suggestions for moving forward with standards that are both technically sound and legally defensible: (1) subcategorize small dehydrators appropriately and develop MACT floors for each subcategory and (2) identify de minimis emission levels for dehydrators with insignificant emission levels.

20.4.1. EPA Must Properly Subcategorize Small Dehydrators and Establish Legal and Technically Feasible Standards

The analyses discussed above demonstrate that EPA has not properly subcategorized or otherwise appropriately accounted for fundamental differences among small dehydrators in determining the “classes, types, and sizes” of sources to be regulated. The record clearly shows that the cost of controlling HAP emissions from small dehydrators varies considerably, depending on such factors as concentration of HAP/BTEX in the inlet gas, throughput, and the type and efficiency of control measures. While EPA has attempted to account for some of these factors in the form of the equation-based standard, the cost data described above in Tables 20-3 and 20-5 (which show that the cost of compliance for certain classes of small dehydrators will be inordinate) prove that the form of the standard fails to properly accommodate certain classes of small dehydrators. EPA has ample authority to further subdivide the population of small dehydrators to make sure the standard reasonably fits each affected dehydrator. *See Sierra Club v. EPA*, 479 F.3d 875, 885 (D.C. Cir. 2007) (Williams concurring) (“[O]ne legitimate basis for creating additional subcategories must be the interest in keeping the relation between “achieved” and “achievable” in accord with common sense and the reasonable meaning of the statute.”). In the face of the cost data showing inordinate impacts on certain small dehydrators, the Agency’s failure to consider alternative groupings of small dehydrators is arbitrary and capricious.

EPA recognized differences in emission potential based on factors such as inlet BTEX concentration and throughput, as evidenced by the attempt to develop an equation to adjust the emission limitation based on these factors. However, as proven above, this approach was entirely insufficient. The proposed subcategorization scheme and resulting equations would require controls on every dehydrator, no matter how low the natural BTEX level or the potential dehydrator emissions. That is not the CAA’s intent of an emission “floor.”

API examined EPA’s small dehydrator dataset^{xx} to evaluate potential subcategorization and MACT floor options. Table 20-6 illustrates EPA’s small dehydrator dataset sorted by uncontrolled BTEX emissions.

^{xx} Memorandum. From Heather Brown, P.E, EC/R Incorporated, to Bruce Moore and Greg Nizich., EPA/OAQPS/SPPD/FIG. “Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options”. July 28, 2011. (Docket Item EPA-HQ-OAR-2010-0505-0047)

Table 20-6. Summary of EPA's Small Dehydrator Dataset

EPA Unit ID No.	BTEX Emissions (tpy)		Benzene Emissions (tpy)		BTEX Inlet Concentration (ppmv)	Throughput (MMSCFD)
	Actual	Uncontrolled	Actual	Uncontrolled		
G	0.02	0.02	0.02	0.02	5	1.6
E	0.1	0.1	0	0	39	1.5
A	0.004	0.2 ¹	0.001	0.05 ¹	116	0.62
R	0.2	0.2	0.1	0.1	150	0.1
D	0.6	0.6	0.6	0.6	140	3.5
F	0.9	0.9	0.4	0.4	308	1.04
B	1.1	1.1	0.1	0.1	69	20
W	1.2	1.2	0.3	0.3	102	0.65
HH	1.5	1.5	0.7	0.7	410	0.09
GG	1.9	1.9	0.2	0.2	39	1.34
Y	2.4	2.4	0.2	0.2	157	0.75
DD	3	3	0.2	0.2	19	6.34
Q	3.5	3.5	0	0	50	5.8
M	3.8	3.8	1.2	1.2	400	1.2
T	3.9	3.9	0.4	0.4	216	1.2
C	0.084	4.2 ¹	0.007	0.35 ¹	60	1.6
J	4.4	4.4	3	3	823	0.7
S	4.5	4.5	1.5	1.5	400	0.8
EE	4.6	4.6	1.2	1.2	500	0.32
O	4.71	4.71	0.99	0.99	348	1.3
U	4.8	4.8	0.5	0.5	316	1
I	5.02	5.02	0.64	0.64	40	17.5
BB	5.3	5.3	0.7	0.7	198	1.21
Z	5.4	5.4	0.7	0.7	2,560	0.1
K	6.5	6.5	4.6	4.6	1,499	0.55
AA	6.9	6.9	1.3	1.3	320	1
H	7.9	7.9	4.9	4.9	1,560	1
P	10.4	10.4	0.8	0.8	174	5.11
V	11.7	11.7	1.3	1.3	329	2
X	13.8	13.8	0.6	0.6	668	1.1
L	17.7	17.7	1.7	1.7	1,400	1.6
FF	2.5	125 ¹	0.2	10 ¹	32	2.3
N	7.5	375 ¹	5.1	255 ¹	340	2.2
CC	59.3	2,965 ¹	10.5	525 ¹	920	2.7

¹ Emissions from these dehydrators were identified as controlled. A control efficiency of 98% was assumed to calculate the uncontrolled emissions.

If the outliers created by applying an assumed 98% control efficiency to the controlled streams are not considered (this assumption resulted in uncontrolled BTEX emissions of 125 tpy, 375 tpy, and 2,965 tpy), the data do show some expected outcomes. For example:

- The average emissions for the 25% lowest inlet BTEX concentrations are 2.5 tpy BTEX and 0.2 tpy benzene, while the remaining 75% have average emissions of just over 5 tpy BTEX and 1.2 tpy benzene.
- The BTEX emissions for the lowest 25% of the throughputs average 3 tpy, while the BTEX emissions for the remaining 75% of the data set with higher throughputs average over 5 tpy.

However, the average benzene emissions from the lowest 25% throughput dehydrators (1.3 tpy) are actually higher than the average benzene emissions for the higher throughput dehydrators (0.8 tpy).

Evaluation of all the data show a slight correlation between BTEX emissions and inlet BTEX concentration ($R^2 = 0.2$), but the data show a decrease in BTEX emissions with increasing throughput.

In conclusion, this cursory analysis of EPA's dataset (see Attachment R) indicates that neither inlet BTEX concentration or dehydrator throughput have a sufficient correlation with emissions to further break small dehydrators into technically and legally sound subcategories based only on these characteristics.

Therefore, API recommends that an uncontrolled emissions threshold be established to subcategorize small dehydrators. Given the large number of variables that impact emissions from dehydrators, emissions are the most relevant and comprehensive indicator of differences in dehydrator class, type, and size.

Further, EPA has already established the appropriate threshold for this subcategorization – 0.9 Mg/yr (1 tpy) benzene. During the original development of subparts HH and HHH, EPA established this 0.9 Mg/yr level “for owners or operators of facilities with low BTEX concentrations in the natural gas”^{YY}. Therefore, API recommends that the small dehydrator subcategory for oil and natural gas production (subpart HH) be separated into (1) those dehydrators with uncontrolled average benzene emissions less than 0.9 Mg/yr and (2) those dehydrators with uncontrolled average benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates less than 85,000 SCMD. For natural gas transmission and storage, these subcategories are (1) those dehydrators with uncontrolled average benzene emissions less than 0.9 Mg/yr and (2) those dehydrators with uncontrolled average benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates less than 283,000 SCMD.

Once the subcategories are established, EPA must then determine MACT floors for each subcategory. EPA's dataset available in the docket does not include sufficient levels of detail to fully evaluate process variations or other factors that influence emissions. More importantly, there is no way that EPA can determine whether any simple “floor” level calculated from these data can be achievable by all dehydrators in the subcategory. This is especially germane in this situation where many aspects that impact emissions are not under

^{YY} National Emission Standards For Hazardous Air Pollutants For Source Categories : Oil And Natural Gas Production And Natural Gas Transmission And Storage - Background Information For Final Standards: Summary Of Public Comments And Responses. EPA-453/R-99-004b. May 1999.

the control of the owner or operator. However, the owner or operator can ensure that the dehydrator is operated in a manner to reduce emissions to the maximum extent possible without add-on controls by optimizing the glycol circulate rate. This practice is already recognized as an effective method by EPA and is required by §63,764(d)(2) for area source dehydrators not located within an urbanized area (UA) plus offset and urban cluster (UC) boundary, as defined in §63.761 of subpart HH.

This is a clear example of the type of “design, equipment, work practice, or operational standard, or combination thereof,” standard allowed under section 112(h) of the CAA. To establish standards under the authority of 112(h), the CAA requires EPA to establish that:

- (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law, or
- (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

In many situations, the emissions from these low-emitting dehydrators are below the detection limit of prescribed test methods. This clearly meets the criteria in paragraph (B) above, justifying the establishment of standards that require the optimization of glycol circulation rate to reduce emissions.

As dehydrator emissions increase (i.e., are above 0.9 Mg/yr), the ability to effectively control increases and differences in inlet BTEX concentration, throughput, and other variables are less critical. Therefore, API believes it is technically valid and legally defensible to determine the MACT floor for those small dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater.

For oil and natural gas production, the average of the lowest 5 emitting dehydrators (since there are less than 30 dehydrators in the data set for the subcategory) is 4 tpy BTEX. For natural gas transmission and storage, there is only one dehydrator in the dataset with benzene emissions of 1 tpy or greater, and the BTEX emissions for this dehydrator are 5.5 tpy.

In summary, API offers the recommendations shown in Table 20-7.

Table 20-7. Recommended Subcategories and Standards for Small Dehydrators

Recommended Dehydrator Subcategory	Recommended MACT Floor/Standard
Oil and Natural Gas Production	
Dehydrators with uncontrolled benzene emissions less than 0.9 Mg/yr	Optimize glycol circulation rate in accordance with §63,764(d)(2)
Dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates of less than 85,000 SCMD	BTEX Emissions < 3.6 Mg/yr or 95% reduction ¹
Natural Gas Transmission and Storage	
Dehydrators with uncontrolled benzene emissions	Optimize glycol circulation rate in accordance

less than 0.9 Mg/yr	with §63.764(d)(2)
Dehydrators with uncontrolled benzene emissions of 0.9 Mg/yr or greater and actual annual average flow rates of less than 283,000 SCMD	BTEX Emissions < 5.0 Mg/yr or 95% reduction ¹

¹ A mass emissions limit imposes complicated and costly compliance and recordkeeping obligations when contrasted with a control efficiency standard. Therefore, API recommends that small dehydrators have the option to comply with 95% control requirements for large dehydrations in §63.765(b) as an alternative to complying the mass emission limitations determined by the equation. API believes that EPA should welcome this option, which would result in greater emission reduction for a lower burden.

If EPA does not decide to adopt API’s recommendations noted above, they must, at a minimum, revisit the proposed subcategorization and MACT floor decisions, which as was clearly shown above, do not meet their statutory-mandated requirements. EPA must then re-propose their updated evaluations and standards.

20.4.2. Dehydrators With No/Low Emission Potential Should Be Considered De Minimis

In MACT standards, EPA has routinely identified equipment with such low HAP emission potential that they should not be regulated.

As was shown in the real-world examples provided in Tables 20-3, 20-4, and 20-5, there are situations across the country where the natural gas being treated in dehydrators has such low benzene, BTEX, and HAP that the emissions will be trivial. API recommends that EPA establish de-minimis levels of HAP emissions that would exempt small dehydrators from all requirements under subparts HH and HHH.

In Alabama Power, the District of Columbia Circuit held that EPA could exempt de minimis sources of air pollution from the requirements of the Clean Air Act (See Alabama Power Co. v. Costle, 636 F.2d 323, 360 (D.C.Cir.1979)).

Glycol dehydrators are a clear example of where the establishment of a de minimis threshold is warranted. API insists there is a strong justification for such a threshold in the oil and natural gas production and natural gas transmission and storage source categories due to the naturally occurring differences in gas composition across the United States and thus, varying differences in dehydrator input stream HAP concentrations, throughputs, and in emissions.

API is recommending that EPA adopt a lower bound threshold below which dehydrators would not be subject to standards. As discussed above, the inlet composition of gas entering the dehydrator is not a stand-alone determiner of HAP emissions. However, situations where the inlet stream contains no BTEX should be exempt from regulation. In addition, API recommends that EPA establish a de minimis emission level. Owners and operators can document their emission level by using GRI-GLYCalc™ or another acceptable emission estimation method. Further, API recommends that this de minimis level be 0.5 Mg/yr total uncontrolled BTEX emissions.

20.5. EPA’s Proposed Equation Does Not Reflect the MACT Floor Determined

As discussed above, API does not believe that any new standards are required for small dehydrators. Further, as also discussed above, if EPA does elect to pursue standards for small dehydrators they must (1) establish reasonable and legal subcategories and promulgate standards reflecting the MACT floor for each subcategory and (2) establish de minimis thresholds to exempt dehydrators with insignificant emissions.

In the event that EPA chooses to continue with the proposed subcategorization approach (which, as clearly demonstrated above, is unlawful and technically unjustified), EPA must make changes to the proposed equations. In short, the BTEX emission limit equation for small dehydrators should not go to zero. For small dehydrators in the oil and natural gas production source category (subpart HH), EPA determined a MACT Floor of 0.286 tpy BTEX. For small dehydrators in the natural gas and production source category (subpart HHH), EPA determined a MACT floor of 1.45 tpy BTEX. However, the equations proposed in the rules approach a mass limit of zero.

This was undoubtedly an inadvertent error by EPA in the proposed equation, as it does not represent the MACT floor calculated. The equation would give the intended result if the product of Throughput and Concentration ($C_{i,BTEX}$) were assigned a lower bound, as shown below. This correction to the equation would result in a minimum emission limit of 0.286 tpy BTEX for oil and natural gas production and 1.45 tpy BTEX for natural gas transmission and storage (i.e., the MACT floors), rather than 0.

For Equation 1 in subpart HH:

$$EL_{BTEX} = (1.10 \times 10^{-4})(\text{Throughput})(C_{i,BTEX})(365 \text{ day/yr})(1 \text{ Mg}/10^6 \text{ g})$$

where:

$$EL_{BTEX} = \text{Unit-specific BTEX emission limit (Mg/yr)}$$

$$1.10 \times 10^{-4} = \text{BTEX emission limit (g BTEX}/(\text{standard m}^3 - \text{ppmv}))$$

$$\text{Throughput} = \text{annual average daily natural gas throughput (standard m}^3/\text{day)}$$

$$C_{i,BTEX} = \text{BTEX concentration of the natural gas at the inlet to the glycol dehydrator unit (ppmv)}$$

If:

$$\underline{(\text{Throughput})(C_{i,BTEX}) < 6.46 \times 10^6 (\text{standard m}^3 - \text{ppmv})/\text{day},}$$

then set:

$$\underline{(\text{Throughput})(C_{i,BTEX}) = 6.46 \times 10^6 (\text{standard m}^3 - \text{ppmv})/\text{day}.}$$

For Equation 1 in subpart HHH:

$$EL_{BTEX} = (6.42 \times 10^{-5})(\text{Throughput})(C_{i,BTEX})(365 \text{ day/yr})(1 \text{ Mg}/10^6 \text{ g})$$

where:

EL_{BTEX} = Unit-specific BTEX emission limit (Mg/yr)

6.42×10^{-5} = BTEX emission limit (g BTEX/(standard m^3 – ppmv))

Throughput = annual average daily natural gas throughput (standard m^3 /day)

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydrator unit (ppmv)

If:

$$(\text{Throughput})(C_{i,BTEX}) < 5.61 \times 10^7 \text{ (standard } \text{m}^3 \text{ – ppmv)/day,}$$

then set:

$$(\text{Throughput})(C_{i,BTEX}) = 5.61 \times 10^7 \text{ (standard } \text{m}^3 \text{ – ppmv)/day.}$$

A mass emissions limit imposes complicated and costly compliance and recordkeeping obligations when contrasted with a control efficiency standard. Therefore, API recommends that small dehydrators have the option to comply with 95% control requirements for large dehydrations in §63.765(b) as an alternative to complying the mass emission limitations determined by the equation. API believes that EPA should welcome this option, which would result in greater emission reduction for a lower burden.

If EPA's proposed equation were to be promulgated, it represents a level of control beyond the MACT floor. This is clearly demonstrated above in Table 20-4, as the proposed equation for subpart HH would result in every dehydrator in the top 12% of the dataset, save one, to install controls. EPA estimates that the incremental cost effectiveness of beyond the floor controls to be \$167,200/Mg for oil and gas production small dehydrators (40 FR 52768) and \$33,000/Mg for natural gas transmission and storage small dehydrators (40 CFR 52769). In both cases, EPA clearly stated that they did not believe these cost effectiveness values were reasonable. If EPA does not adjust the equations in accordance with the above suggestions, then they are in effect accepting these unreasonable cost effectiveness values. API does not believe this is justified and maintains that EPA must not promulgate the equations as proposed.

20.6. Clarification of Terminology

API maintains that the following changes are needed to clarify terminology related to glycol dehydrators.

20.6.1. Boiler Definition

In the NESHAP boiler definition, the rule must clarify that glycol reboilers are not boilers.

§63.761

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10. [This definition excludes line heaters and glycol reboilers.](#)

20.6.2. Glycol System Condensers are not Control Devices

EPA uses the term “condenser” multiple times in the rule when describing control devices and requirements. It is not uncommon for a condenser on a dehydrator vent stream to precede a flare or other combustion device. A key purpose of this condenser is to remove water vapor. Since the 95% HAP emission reduction is met by the flare or combustion device, it is not reasonable to consider the condenser as a control device in this situation and require all the associated monitoring, recordkeeping, and reporting requirements. We therefore, request that only condensers that are the final control device, or condensers used to help achieve the 95% control efficiency, be classified as control devices. We ask that EPA clarify that condensers which are part of a glycol system prior to a control device should not be considered control devices.

21. PRODUCED WATER EVAPORATION PONDS

EPA solicited comments on several questions regarding produced water evaporation ponds in the Preamble. EPA stated, “*We believe that produced water ponds are also a potentially significant source of emissions, but we have only limited information. We, therefore, solicit comments on produced water ponds...*”

It is wrong for EPA to conclude that produced water ponds are “a potentially significant source of emissions,” especially based on their statement that “limited information” is available. In fact, there is no information to date indicating that produced water ponds are significant emission sources. The appropriate method for determining potential impacts is to rely on a valid scientific approach to addressing the concern. Preferably that would include determining what information is available, evaluating available data to determine data gaps, developing a plan to fill data gaps, and evaluating the updated data set. With that in mind, industry is open to cooperating with EPA in an appropriate manner to address their concerns.

Here are the questions that EPA included and our responses.

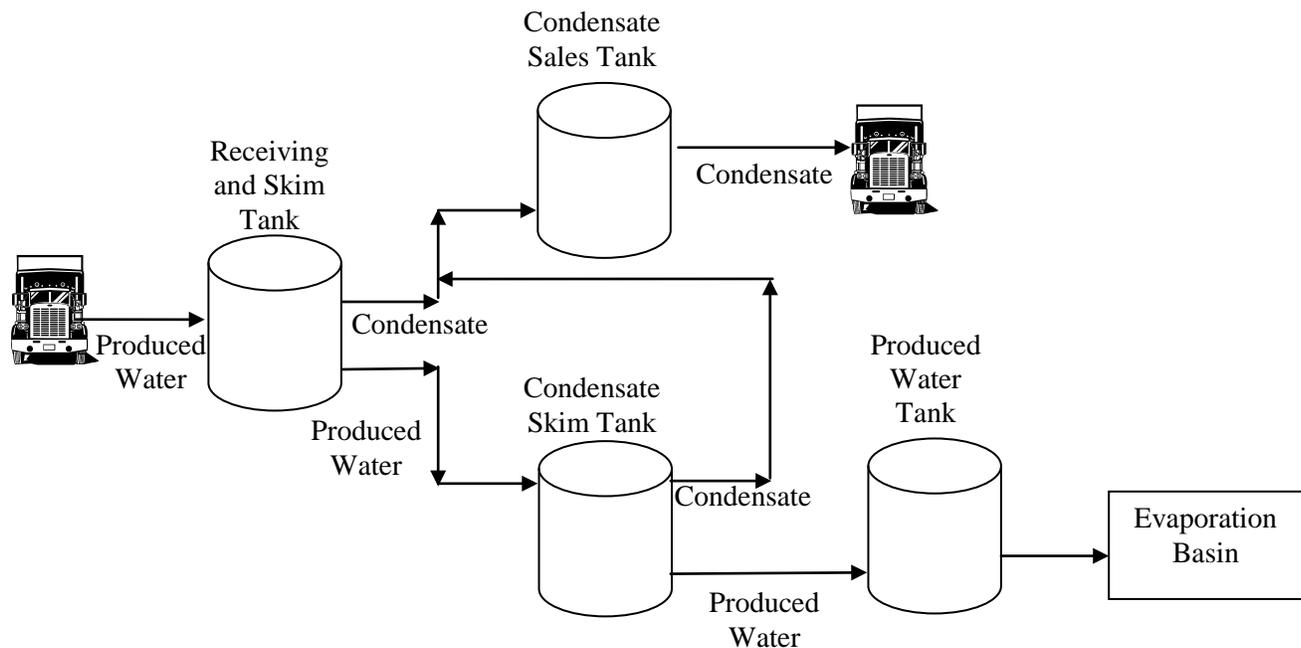
(a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation.

Any model used for calculating emissions will depend upon valid input data. All inputs must be confirmed, subjected to quality analysis, sensitivity tested, and validated. Initial input VOC concentrations to ponds, local climatic conditions, biodegradation potential, sorption to solids and other parameters must be properly determined through process examination or measurement.

The Endangered Species Act strictly limits the amount of hydrocarbons that can be on an unnetted pond. Consequently, evaporation pond operators are very sensitive to the existence of hydrocarbons on/in a pond

and they take extensive steps to prevent them. Typically, oil /condensate and water are separated initially at the wellhead with a three phase separator. Then the produced water enters a tank. Any oil or condensate entrained in the produced water then separates out in the produced water tank. Trucks are used to vacuum the oil or condensate from the top of the tank. The produced water is then trucked to the evaporation pond facility. There additional separation is done using a series of skim oil tanks as shown below. The produced water then enters the evaporation pond. Hydrocarbon emissions from the evaporation ponds are minimized since almost no separate phase hydrocarbon remains in the produced water placed into the evaporation ponds.

Figure 20-1. Process Flow for Produced Water To Evaporation Basins



As far as estimating emissions, WATER9 is the only EPA approved method for calculating emissions from evaporation basins. The assumptions in this model are quite conservative and tend to overestimate emissions, not underestimate emissions. Assuming 100% of VOCs in the water enter the atmosphere is a completely false assumption that ignores the fate and transport of various chemicals. Many chemicals, like methanol, have a very high affinity for water and do not evaporate. Also, many chemicals, like methanol, can only be removed from water using biodegradation. EPA's "Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1"^{ZZ} found minimal emissions from the evaporation ponds.

The Office of Pollution Prevention and Toxics of the U.S. Environmental Protection Agency (EPA) acknowledges that "most methanol is removed from water by biodegradation"^{AAA}. The Hazardous Substances Data Bank of the National Library of Medicine says that aquatic hydrolysis, oxidation, and

^{ZZ} <http://www.epa.gov/nrmrl/pubs/600r09132/600r09132.pdf>

^{AAA} United States Environmental Protection Agency, Office of Pollution and Toxics. *Chemical Summary for Methanol, Report No. EPA749-F-94-013a*. United States Environmental Protection Agency, August 1994.

photolysis are not significant fate processes for methanol^{BBB}. Additionally, in 1999, Malcolm Pirnie conducted a study for the American Methanol Institute called "Evaluation of the Fate and Transport of Methanol in the Environment"; part of this study included reviewing the losses of methanol in water. Malcolm Pirnie found that the dominant loss mechanism was biodegradation^{CCC}. According to a 1991 study "The reported half-life of methanol in surface waters under aerobic conditions is short and has been reported to be as low as 24 hours^{DDD}". In fact, the half-life of methanol even in anaerobic conditions is from 1 to 5 days^{EEE}.

Since methanol is very polar and stable in water, hydrolysis does not contribute significantly to methanol removal from bodies of water. Photolysis is not a significant contributor to methanol degradation either since methanol does not absorb light in the visible spectrum and long wavelength UV. Methanol does, however, absorb very short wavelength ultra violet (UV), which is present in negligible amounts in solar radiation. "In addition, methanol can be naturally oxidized by hydroxyl radicals formed in the water by the photolysis of nitrate, nitrite, and hydrogen peroxide resulting from reactions with excited humic material or from the reaction with H₂O₂ with Fe(II)"^{FFF}.

Bioaccumulation in aquatic organisms is expressed in bioconcentration factors (BCF). The bioaccumulation in solids and organic materials is expressed as the octanol-water coefficient. The BCF and octanol-water partition coefficient for methanol, as represented in the Malcolm Pirnie study, was less than ethanol and significantly less than for benzene. Thus the bioaccumulation of methanol is fairly low. Further, since methanol has a low partition air/water coefficient and a rate of biodegradation that exceeds the rate of volatilization, volatilization is not a primary source of methanol losses either. The half-life of methanol from volatilization is 60 days in comparison to 24 hours for biodegradation^{GGG}. This comparison leads to the conclusion that the most of the methanol losses in water are from biodegradation.

The EPA WATER9 model considers biodegradation, bioaccumulation of solids and organic materials, and volatilization of chemicals in water. Since photolysis is not a significant contributor to methanol losses, WATER9 is an acceptable tool to use to estimate methanol emissions to air from wastewater. WATER9 predicts that the emissions of methanol decrease as temperatures increase. The phenomenon occurs because biodegradation increases with temperature, leaving less material to volatilize. Additionally, volatilization is much slower than biodegradation for methanol. Enviromega determined that WATER8 (the predecessor to WATER9) predicted methanol emissions at a relatively high rate because the biorate coefficient was

^{BBB} Hazardous Substances Data Bank (HSDB), MEDLARS Online Information Retrieval System, National Library of Medicine, 1994.

^{CCC} Malcolm Pirnie, Inc. *Evaluation of the Fate and Transport of Methanol in the Environment*. Oakland, California: Malcolm Pirnie, January 1999.

^{DDD} Howard, C. E., Baker, J. F., O'Hannesin, S. F., Vandergriendt, M. and Gillham, R. W. *Transport and Fate of Dissolved Methanol, Methyl-Tertiary-Butyl-Ether, and Monoaromatic Hydrocarbons in a Shallow Aquifer*, American Petroleum Institute Publication No. 4601. American Petroleum Institute, 1991.

^{EEE} Howard, C. E., Baker, J. F., O'Hannesin, S. F., Vandergriendt, M. and Gillham, R. W. *Transport and Fate of Dissolved Methanol, Methyl-Tertiary-Butyl-Ether, and Monoaromatic Hydrocarbons in a Shallow Aquifer*, American Petroleum Institute Publication No. 4601. American Petroleum Institute, 1991.

^{FFF} Schwarzenbach, R. P., Gschwend, P. M and Imboden, D. M. *Environmental Organic Chemistry*. New York: John Wiley & Sons, Inc., 1993.

^{GGG} Malcolm Pirnie, Inc. *Evaluation of the Fate and Transport of Methanol in the Environment*. Oakland, California: Malcolm Pirnie, January 1999.

erroneously assumed low relative to the stripping coefficient^{HHH}. Later, Enviromega was retained by a large manufacturing association to estimate the biodegradation rate coefficient for methanol using a version of 40 CFR 63, Appendix C, Method 304. First order biodegradation rate coefficients were estimated by Enviromega. The biorate coefficients for methanol determined by this study were two orders of magnitude higher than in the WATER8 model. The Monod first order biodegradation rate from their study was -32.6 L/g-h at 22°C and in WATER8 it is only -0.2 L/g-h^{III}. The table below summarizes the findings from Enviromega's study.

Comparison of Methanol First Order Biodegradation Rate Coefficients

Compound	Initial MeOH Con. (mg/L)	No. of Data Points	K ₀ (mg/L-min.)	r ²	Monod Parameters			
					Montheith Study		WATER8	
					K _{max} (mg/g VSS-h)	K _s (mg/L)	K _{max} (mg/g VSS-h)	K _s (mg/L)
Methanol	20	6	-0.185	0.988	-11.08	0.34	-18	90
	15	5	-0.365	0.909				
	10	5	-0.246	0.870				
	5	4	-0.236	0.694				
Ethanol	20	5	-0.117	0.974	-6.14	0.36	-8.8	9.8
	15	5	-0.168	0.944				
	10	4	-0.137	0.940				
	5	4	-0.121	0.762				

Enviromega found that the emissions from various units using the biorate coefficient from their study were lower than the emissions using the biorate coefficient from WATER8. The largest difference was in the activated sludge unit, which had 0.03 g/d of methanol emissions using biorate coefficient from their study compared to 0.8 g/d of methanol using the biorate coefficient from WATER8. Based on this information, the methanol emissions estimated by the EPA models WATER8 and WATER9 are significantly conservatively high.

(b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content.

Evaporation pond operators use pre-treatment facilities to ensure that free hydrocarbons do not enter the ponds as discussed above. The limited comment period has not allowed for time to gather comprehensive data on the concentrations of VOCs in produced water evaporation ponds but they are believed to be very insignificant. While the water cut of some wells may increase with age, there is an insufficient database of information on the VOC content of such waters over time to come to any reasonable conclusion as to increases or decreases in VOC content that may occur over the life of a well. In the case of wells completed

^{HHH} Enviromega. *Estimation of Methanol Biodegradation Rate Coefficient Using EPA's Method 304*. Wastewater Toxics, <http://www.enviromega.com/methbio.htm>.

^{III} Montheith, H. D. and Tischler, L. F. *Testing EPA's Method 304: Biodegradation Rates for Methanol and Other Oxygenated Solvents in a Pharmaceutical Wastewater*. Flamborough, ON, Canada: Enviromega Ltd., 1996.

in shale formations, the water flow from such diminishes rapidly following completion and usually has a minimal flow rate over time.

(c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those warrant control and, if so, how controls should be developed.

There is no such thing as a "typical" evaporation facility. The limited comment period has not allowed for time to gather comprehensive data for determining a statistically valid set of data for pond size and throughput. Throughput may range from a few barrels a day to several thousand. There are facilities with a simple gun barrel separator and a small pond to facilities with multiple stages of inlet separation and multiple ponds. Evaporation ponds are the least likely facilities in upstream oil and gas to provide cost effective reductions in VOC or HAP.

(d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well.

Salable hydrocarbons are captured prior to entering the pond as described above, using existing recovery technologies. As EPA's intent of this question is likely to determine just that, API suggests that EPA conduct a valid study. The complexity of the study might range from well planned mass balance calculations to more detailed data collection and analysis. Industry welcomes the opportunity to cooperate with EPA on any necessary study performed with sufficient time allotted.

(e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints.

Typically, evaporation ponds are placed in locations with access to 3-phase power to operate pumps, aerators, and lighting. The main limitation is that the VOC concentrations in the produced water are already extremely low. Further treatment to remove VOCs would be quite difficult and expensive and would bear little environmental benefit.

(f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency.

Traditional gravity separation as described above is very effective. More sophisticated technology has been much less effective. Industry may be able to respond further if provided the information that led EPA to conclude that existing separation technologies are not effective, and with sufficient time to respond.