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The Honorable Scott Pruitt, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-HQ-OAR-2017-0346 & EPA-HQ-OAR-2010-0505
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Three Month Stay of Certain Requirements & Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements

Dear Administrator Pruitt:

The American Petroleum Institute ("API") is pleased to submit the attached comments on the proposed rule to extend the compliance dates for certain portions of the New Source Performance Standards ("NSPS") 40 C.F.R. Part 60 Subpart OOOOa, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements" 82 Fed. Reg. 27645 (June 16, 2017) ("Proposed Rule"). API previously submitted comments on the legal authorities the United States Environmental Protection Agency ("EPA" or "Agency") possesses to issue a two-year stay of these provisions. These comments expand further on some of the technical issues and challenges industry would face in the absence of staying the provisions.

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 10.3 million jobs and 7.6 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Most of our members conduct oil and gas development and production operations and are directly impacted by these proposed actions.

Throughout the development of the 2012 oil and gas NSPS rule and its amendments in 2016, API has maintained a collaborative working relationship with Agency staff to provide operational and emissions data to inform the developments of these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions for new

sources and, as a co-benefit, also reduce methane. API encourages EPA to proceed with its review and revision of the underlying rule as expeditiously as possible, based on sound science and economics, considering the operational and technical issues that have already been raised in comments and litigation.

While the agency has proposed to extend the compliance dates for a targeted subset of the rule requirements for two years, there is nothing preventing the agency from reconsidering these issues, along with the other technical issues raised in API's August 2nd petition, in less than two years. Going forward, the agency should consider addressing any issues, on an expedited timeline, that can be easily addressed to provide the clarity the industry is seeking to comply with the rule.

Please contact me (202-682-8319) if you have any questions regarding the comment submittal.

Sincerely,

Matthew Todd

cc: Mandy Gunasekara, USEPA
Sarah Dunham, USEPA
Steve Page, USEPA
Peter Tsirigotis, USEPA
Kevin Culligan, USEPA
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API's Technical Comments on EPA's Proposed Rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements"
82 Fed. Reg. 27645 (June 16, 2017)

Docket ID No. EPA-HQ-OAR-2010-0505, EPA-HQ-OAR-2017-0346

On July 27, 2017, API submitted comments¹ to the EPA regarding the legal authorities the agency possesses to extend the relevant compliance deadlines of the Subpart OOOOa provisions. The following comments expand further on some of the technical issues and challenges industry would face in the absence of a targeted extension of the compliance deadlines or staying of certain rule provisions.

In our August 2, 2016 petition, API raised specific technical issues that warrant reconsideration and review of the rule by the Agency. These issues still require attention, as do the issues raised by others, including the Independent Petroleum Association of America (IPAA), Texas Oil and Gas Association (TXOGA), and the Gas Processors Association (GPA).

More specifically, the following issues support the need to provide a 2-year compliance extension while the Agency considers new information and assesses its impacts as part of the reconsideration process.

1. Leak Detection and Repair

a. Delay of Repair

The language finalized in Subpart OOOOa regarding delay of repair of an identified fugitive leak requires more clarity because the language in §60.5397a(h)(2) erroneously presumes that various shutdown events and well shut-ins would result in the blowdown of all equipment located on-site, including the leaking component on delay of repair. This is not accurate and can lead to an untenable lack of clarity regarding compliance expectations.

§60.5397a(h)(2) states:

If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. (Emphasis added)

While the concept of delayed repair is appropriate and necessary, the language underlined above describes events that may not present safe conditions to perform the repair. The delay of repair

¹ Docket ID No: EPA-HQ-2010-0505-10577

provisions as written do not reflect the realities of well site and compressor station operation, where blowdowns can occur as part of standard operations to prevent safety concerns. Unscheduled and emergency shutdowns occur from time to time, and can last a very short time before service is returned. As written, the rule requires operators to make repairs following a blowdown or during an unscheduled or emergency shutdown and this requirement does not allow adequate time to make certain repairs that require parts, logistical prearrangements, skilled labor, etc. While these situations will occur infrequently and most repairs will be completed expeditiously, operators must have flexibility to delay repair when warranted. Although such situations are expected to be infrequent, the rule requirements have the potential to lead to prolonged shutdowns that could last days or weeks.

Additionally, the language in §60.5397a(h)(2) presumes that various compressor station shut down events and well shut-ins would necessarily result in the blow down of all equipment located on site (including the component on delay of repair). This is not accurate. For example, some equipment on site may remain isolated, but under pressure (such as the line pressure of the site). As written, the rule language could be interpreted to mean that all equipment must be depressurized during a shutdown in order to repair the leak. In such circumstances, the emissions from forcing blow down of all equipment can be greater than the emissions associated with the component on delay of repair. API does not believe EPA's intent was to create such scenarios.

Further, other federal and state LDAR regulations do not require that repairs be made immediately during emergency or unscheduled shutdowns. For example, 40 C.F.R. § 60.482-9a, Subpart VVa, allows delay of repair if the parts must be ordered and the repair must be made during a unit shutdown. Similar provisions are provided in state regulations as well (e.g., PA, WV, CO).

Imposition of these requirements during the pendency of the reconsideration is very burdensome, and in some cases infeasible. The agency should provide additional time to work with stakeholders to better understand and account for the nature of operations and update the rule language accordingly to resolve the problems and unintended potential impacts to both operation and the environment associated with compliance with these provisions.

b. Legal Complications associated with 3rd-Party Equipment

As written, the leak monitoring and repair requirements appear to apply to all equipment at a well site or compressor station regardless of ownership. As EPA acknowledged in its response to comments made by the Gas Processors Association, EPA intended to include third-party equipment, but supported such intention by simply stating that arrangements can be made to address and handle these situations (see EPA-HQ-OAR-2010-0505-6881, Excerpt 4). This response and

assumption was an oversimplification of what can be very complicated site configurations and contractual arrangements.

As an example, there are many instances where insignificant equipment owned by a midstream company, such as a meter run, is located at a well site along with equipment owned and operated by the producer. There are legal and logistical issues that can prevent the midstream operator from being able to comply with Subpart OOOOa for that small piece of equipment based on actions made by another operator. There are significant practical issues with renegotiating contractual obligations on the thousands of sites that may be impacted by these requirements.

Imposition of these requirements during the pendency of the reconsideration is very burdensome, and in some cases infeasible. The agency should provide additional time to work with stakeholders to better understand and account for the nature of operations and update the rule language accordingly to reflect the reality that equipment owned, operated, or leased by one operator is legally distinct and cannot be subject to requirements triggered by another operator.

c. Low Production Wells²

Well sites with equipment configurations or component counts significantly less than EPA's model plants should be exempt from the LDAR requirements based on cost effectiveness. EPA is not correct in their Response to Comments (EPA-HQ-OAR-2010-0505-6983, Excerpt 17) when suggesting that the model plant cost analysis should equate to all well sites, even those with significantly fewer components, since there are larger well sites that have more components.

The best system of emission reduction (BSER) is not based on a calculated average value, but rather it establishes a threshold limit where controlling a source above the threshold is considered cost effective and controlling a source below the threshold is not. One example of this is found in 40 CFR Part 60, Subpart JJJJ where applicability and levels of control are linked directly to rated horsepower, which is generally proportional to potential emissions. There is a threshold (e.g., rated horsepower) where technology emission limits are cost effective and below which they are not. As communicated to the Agency previously, API continues to recommend EPA apply a similar approach for low production wells in regards to LDAR because the typical count of components at those facilities is substantially less than the EPA's model plant analysis and LDAR does not meet the criteria to be considered BSER for low production well sites.

Additionally, low production wells are typically located on single well pads. Therefore, the "special analysis of producing crude oil and natural gas wells from the DrillingInfo HPDI database" (see page

² See Section 27.2.4 of API December 4, 2015 comments for additional discussion.

50 of EPA's August 2015 Background Technical Support Document(TSD)) that EPA used to determine a two-well model production site is not representative of new or modified low-production wells. The two-well site model used in the BSER analysis may have overstated, by at least a factor of two, the number of fugitive emission components at a typical new or modified low production well site.

In the proposed rule, it was also EPA's understanding that *"such well sites are inherently owned and operated by small businesses."* Revising the final rule to include low-production wells may have inadvertently created problems for some small businesses that drill new low production wells.

d. Unaccounted Impacts in BSER Analysis from 60% Reduction Efficiency Assumption for Semiannual Monitoring

EPA made a material mistake in assuming a 60 percent reduction in fugitive emissions due to completing semiannual fugitive monitoring surveys. In the preamble for the proposed Subpart OOOOa rule, EPA stated, *"Therefore we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analysis."* (See 81 FR 56635 and page 70 of August 2015 Background TSD). EPA solicited comments on these assumed emissions reductions, but retained the 60% reduction for semiannual frequency and 40% reduction for annual frequency when finalizing the rule.

However, a review of the Colorado document³ shows the CAQCC stated that, *"Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections."* This would suggest that the emissions reductions for semi-annual inspections should be estimated at 50%, but not 60%. Colorado did not provide additional information for the EPA source; however, it is likely it includes data from Table 5-2 Control Effectiveness for an LDAR Program at a SOCFI Process Unit of EPA's Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017).

A 50% emission reduction versus a 60% emission reduction would mean a 17% lower reduction in fugitive emissions for semi-annual frequency, which is not reflected in the BSER analysis to determine cost-effectiveness of the final rule's leak monitoring and repair provisions. A 17% lower reduction in fugitive emissions would increase the cost/ton of pollutant reduction by 20% ($1/0.83 = 1.20$).

³ Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9)*. November 15, 2013.

e. The Alternative Means of Emission Limitation (AMEL)

The AMEL provisions included in the rule are not sufficiently clear to facilitate effective application and approval of AMEL, and therefore fail to serve their intended purpose. The ability to apply for and obtain AMEL for fugitive emissions requirements determines whether operators of well sites and compressor stations, in particular those subject to existing state programs or those which have invested in emerging detection technology, must now redirect or expend additional resources and efforts to implement the 2016 Rule's fugitive emissions requirements. This may negatively impact or otherwise complicate compliance with applicable state programs and/or progress in using emerging technology while providing little to no incremental environmental benefit.

The scale and impact of duplication and overlap with state requirements is significant. Many of the states with the largest oil and gas production and drilling activity already have leak detection and repair programs and requirements in effect, e.g. PA, CO, TX, WY, OH, CA. This means that, until approval is granted through the AMEL process, industry will be spending duplicative effort for little to no environmental benefit in order to demonstrate clear compliance with both state and federal programs. Given the detailed nature of recordkeeping associated with most LDAR programs, the concept of satisfying two different programs for the same facility with similar, but not identical requirements, is a significant burden.

For example, one API member working through an AMEL process for a separate matter has estimated costs for the application process to be at least \$100,000 and approval is still pending. Additionally, for perspective regarding how long the AMEL process can take, one can look to the approval process to operate pressure-assisted multi-point ground flares (MPGF) (Docket#: EPA-HQ-OAR-2014-0738). On August 5, 2014, the Dow Chemical Company requested an AMEL in order to operate pressure assisted multi-point ground flares and on October 21, 2014, ExxonMobil made a similar request. EPA approved the AMEL requests for Dow and ExxonMobil on August 31, 2015, over 1 year after Dow's application. Notably, in the August 31, 2015 approval, EPA recognized the significant amount of time involved with navigating the AMEL process and sought comments on ways to improve EPA's ability to approve future AMEL requests for MPGF in a more efficient and streamlined manner.

With respect to LDAR – an issue for the entire oil and gas industry with known duplicative requirements in multiple states – the only practical and reasonable approach is for EPA to determine how to address equivalency in a streamlined manner rather than subject the entire industry to a long and burdensome AMEL process.

The Agency should provide additional time to work with stakeholders to review and streamline the AMEL process to avoid duplicative requirements and foster the development and approval of emerging technology. It is important to note, the proposed compliance extensions will have minimal environmental impact since many States have requirements that target the same emissions

sources.

2. Obtaining Certification by a Professional Engineer (PE)

Under current rule provisions, many companies face additional costs and project delays for a third-party PE to design and certify closed vent systems and/or certify technical infeasibility associated with control of a pneumatic pump. The PE certification process does not add any significant environmental benefit to the rule provisions since there are provisions in place for ongoing compliance specific to the operation of closed vent systems, a general duty for all operators to minimize environmental impacts, and annual report submittals must be approved by a certifying official. EPA did not justify the extra expense and burden of PE certifications in the final rule. Such certification to achieve compliance with the current rule, is estimated to cost some API members between \$4,000 – 7,500 on average per certification. This adds significant cost and burden, particularly to smaller operators who are less likely to have access to in-house PEs. At least one state, Wyoming, is taking a position that PE certifications for sources located in that state must be completed by a PE registered in Wyoming. While EPA indicated that this was not their intent, EPA failed to determine how state regulations or practices might result in such situations. This new, unanticipated additional burden is not trivial and can result in material cost and schedule impacts on operators.

Additionally, based on a survey of API members, there have been no situations identified to date where a design change was made as a result of the PE review – further validating that this requirement adds burden and cost, while providing no environmental benefit.

3. Pneumatic Pumps at Well Sites

Pumps at “greenfield” well sites are not currently eligible to claim technical infeasibility associated with the control of an affected pneumatic pump. Due to lack of clarity regarding EPA’s intent, the current rule language puts operators into a potentially untenable situation. This occurs if regulatory authorities interpret a “greenfield” well site as synonymous with “new” for Subpart OOOOa thereby removing future technical infeasibility determinations for the entire life of a well site.

Further, EPA failed to provide clarity regarding how boilers and heaters located at well site should be considered. Without a technical infeasibility option, a process heater or boiler would require design around the pneumatic pump’s capacity needs to adequately and safely control a pneumatic pump when it otherwise would not be designed with this feasibility in mind. This may not even be possible in all cases. Further, this is equivalent to requiring installation of a new control device,

which is contradictory to EPA's stated intent that the installation of a control device or process equipment for the sole purpose of controlling a pneumatic pump is not required.