Attachment 1

Detailed Table Presenting Colorado Lesson's Learned

Fugitive Emissions & Equipment Leaks	Comments
Step up and step down	During review of the proposed Colorado Regulation No. 7, Section XVII.F. (*i.e.*, LDAR for well production facilities and natural gas compressor stations), industry commenters, including COGA and the Colorado Petroleum Association (CPA), favored an LDAR inspection frequency that allowed for a step-up or step-down in frequency based upon the number of leaks found. However, Colorado Regulation No. 7 LDAR requirements were finalized with an emissions-based frequency for both well production facilities and natural gas compressor stations without the ability to step-up or step-down in frequency. Colorado operators have been implementing an LDAR program for over a year and generally recognize that a step-up/step-down monitoring frequency approach would be unmanageable. Specifically, many operators perform hundreds of inspections each year (and, in many cases, each quarter). Coordinating those inspections and records already requires a significant amount of time and resources; having to manage an inspection schedule that constantly changes throughout the year would only increase the amount of resources needed and would add another level of difficulty with respect to compliance. In addition, most operators do not currently count components at each well production facility or natural gas compressor station. Based on experience with the Regulation No. 7 LDAR program, COGA and CPA members prefer to either eliminate the step-up/step-down provisions in the Quad Oa proposal or, alternatively, make the provision optional.
Tying LDAR program to emissions profile	The current Colorado Regulation No. 7 LDAR program for well production facilities and natural gas compressor stations determines LDAR inspection frequency based on actual volatile organic compound (VOC) emissions. Thus, actual annual uncontrolled tanks VOC emissions at well production facilities containing tanks storing oil or condensate are used to determine LDAR inspection frequency. Well production facilities without tanks storing oil or condensate utilize total facility controlled actual annual VOC emissions, and compressor stations utilize total facility actual annual fugitive VOC emissions. By determining LDAR inspection frequency based on actual emissions, the inspection frequency will be more frequent at larger facilities that have a higher emissions potential and a corresponding higher potential for fugitive emission leaks. This methodology allows inspection frequency to naturally decrease as emissions decrease without implementing a step-up/step-down in inspection frequency.
Repair and re-inspection deadlines	EPA's Quad Oa proposal places unnecessary constraints on the basis and reasons for repair and includes an unreasonable timeframe for re-inspections. Specifically, EPA generally proposes repair or replacement "as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions." Although EPA suggests that a certain amount of delay in repair/replacement is acceptable when "technically infeasible or unsafe," EPA provides no discussion or definition of what is meant by "technically infeasible." Furthermore, COGA and CPA believe that the terms used by EPA do not adequately capture all appropriate circumstances in which a delay of repair beyond fifteen (15) days may be required. Based on Colorado's experience with its Regulation No. 7 LDAR program, some leaks—approximately 5%, in fact—require more time to repair and re-inspect due to safety issues, weather constraints, the availability of specific parts and equipment, and other considerations that could represent good cause for not meeting the immediate and/or 15-day repair requirement. *See* Colorado Air Quality Control Commission, Public Meeting on October 15, 2015. For

Fugitive Emissions & Equipment Leaks	Comments
	that reason, Colorado's program offers operators additional (and appropriate) flexibility with respect to repair/re-inspection timeframes in its recognition that an extended timeline may be necessary for operators to effectively implement EPA's proposed rules. Therefore, COGA and CPA propose that EPA allow thirty (30) days for the initial repair and thirty (30) days to re-survey after the repair. In addition, EPA should allow operators to demonstrate good cause for any delay of repair, as has been done in Colorado effectively. COGA and CPA recommend that EPA adopt a similar approach to Colorado's under any final Quad Oa rule.
Program development	Many third-party LDAR companies perform regulatory work for LDAR in downstream portions of the petrochemical industry. However, with respect to the upstream segment, most companies that have implemented LDAR programs have done so voluntarily and performed work with internal personnel. Training initial core staff takes considerable time and has required, in many cases, more than a year to have such a program fully operational. Converting these voluntary programs to a regulatory environment may require contracting outside work, implementing tools such as recordkeeping through the use of software, and various other actions that require much more time than originally anticipated.
Inspection technology flexibility	CPA and COGA operators are subject to Colorado's unique, state-wide regulations for monitoring fugitive emissions from new and existing wells and other operations. Experience has shown that, while OGI is a preferred monitoring method over Method 21 in terms of speed of performing monitoring and the ability to monitor most components from the safety of the ground, prescribing OGI as the only monitoring method does not provide flexibility to adopt emerging technologies on a timely basis and may have the unintended consequence of stunting innovation in fugitive emission detection methodology. Additionally, because OGI is not appropriate for all weather or site-specific conditions, additional monitoring methods must be available to operators. There is also no published Reference Method for OGI. Therefore, EPA should not limit fugitive monitoring methodology to just OGI or alternatively to just Method 21. Rather, COGA strongly supports use of language in Quad Oa permitting "other approved methods," as such a revision would welcome innovation and emerging technologies that may be easier and less expensive to operate (which would make it easier for operators of any size to monitor their sites). In conjunction, EPA must accelerate the rate at which additional methodologies and technologies are approved. By accelerating approval of new technologies and methodologies, operators are more likely to invest in and implement more efficient and cost-effective technologies. Such acceleration also will encourage a better rate of compliance which will likely lead to a greater reduction of fugitive emissions. With respect to EPA's proposal for verifying repair of fugitive emission sources, Colorado's experience has been that such verification is not required, and, even if verification were required, use of portable instruments is not the most efficient or cost-effective means of doing so. Specifically, EPA has not permitted use of alternative screening procedures in Method 21, Section 8.3.3 (*i.e.*, soapy water solutions), to determine leak repair thresholds or success; however, Colorado operators have found that a soapy water solution is effective at identifying the location of a range of leak sizes and that it is unnecessary and unduly cumbersome to quantify the repair because not all operators have will have a portable instrument that can quantify leaks. Further, from a practicality standpoint, unless the individual who discovers the leak also repairs the leak at that time, any verification method that automatically requires the use of a camera or portable analyzer adds additional steps to the process and does not necessarily improve emissions. Although most Colorado operators carry a soapy water emulsion, not many have immediate access to a portable instrument analyzer; therefore, requiring verification and quantification of the leak repair would require scheduling an

<table>
<tr><th>Fugitive Emissions & Equipment Leaks</th><th>Comments</th></tr>
<tr><td></td><td>extra visit to a location and additional man-hours, if done in-house, or additional consulting costs, if done by a third party. Logistically, the scheduling of repair verification becomes very difficult when there are a large number of sites or a large number of repairs that may not occur at the same time. (COGA notes that, because EPA is also considering OGI for repair verification, it does not appear that quantification of the repair is necessary from EPA's perspective, given that OGI cannot be used to quantify emissions). By allowing the use of the alternative screening procedure in Method 21 instead of or in addition to OGI/portable instruments, the number of leaks that would have to be verified using a camera or portable analyzer will be limited only to those situations where the soapy water solution does not work; this would also reduce the burden on operators (i.e., effort, cost, and number of site re-visits). Colorado's experience demonstrates that allowing the technician performing the repair to verify the repair using soapy water reduces the time and effort significantly and the time of repair and verification of the repair can be documented in the operator's existing work order system, reducing the need for additional tracking systems.</td></tr>
<tr><td>LDAR for low-pressure CBM/dry gas</td><td>AVO inspections are rarely effective in a low-pressure coalbed methane (CBM)/dry gas field: With respect to audio detection, given the low wellhead pressures, typically 0.5 to 30 psig, and the very low pressures in the associated gas gathering lines, typically less than 15 psi on average (which are consistent with CBM reservoirs), operators are unlikely to hear the small, low-pressure leaks that might occur at the wellhead, pipeline connection, or meter house. Thus, although audio can be useful for higher pressure lines where leaks occur (e.g., discharge lines from a compressor), leaks from low-pressure systems described above will not be audible. With respect to visual detection, methane gas is a colorless gas that cannot be detected by the human eye. With respect to olfactory detection, CBM field in Colorado produce odorless methane (natural) gas with no associated crude oil, condensate, or liquid hydrocarbons and with no sulfur compounds or hydrogen sulfide (or with levels of VOCs that are non-detectable in the gas stream). Therefore, these potential sources of odors are not present in the CBM gas stream. For these reasons, olfactory detection in a CBM field is not effective.

Alternatives to AVO are of little environmental benefit: AVO is unlikely to find the small, low-volume leaks that characterize the type of leak found at a CBM well site. Even where detected using instrumentation such as a forward-looking infrared (FLIR) camera, such leaks are very small given the low wellhead and gathering line pressures characteristic of the CBM well field. For example, after examining two thousand CBM wells in the Raton Basin using FLIR, only two wells were found with leaks greater than 1 cubic-foot/minute, only one of which was audible. The environmental impact from a low-pressure CBM leak is further reduced given the lack of associated VOCs in the gas stream.

After the initial instrument leak detection survey, little environmental or economic benefit flows from repeated leak detection surveys: Surveys of field facilities using detection equipment such as FLIR or remote methane leak detectors have found that repairs are long-lasting and seldom need to be repeated, again because the facilities and equipment are not subject to high gas pressures. Repetition of the initial leak detection survey shows that, overall, the number and size of leaks detected has declined over time. Repair of the low-pressure, low-volume leaks detected is rarely economically justified, but repairs are completed for other reasons such as worker and public safety. For example, in examining over 2000 Raton Basin CBM wellheads, 39 casinghead leaks were found, with an average leakage of 0.648 MCF/day. At current gas prices, an average leak represented an economic loss of less than two dollars a day. In comparison, the rig time necessary to repair one leak costs about $6,000 to $8,000. At over 2000 CBM wells, the two largest well leaks found were 10.8 and 6.8 MCF/d or equivalent to a loss of about $25 and $17 a day.</td></tr>
</table>

Fugitive Emissions & Equipment Leaks	Comments
No need to follow the same walking plan	**Flexibility and site-specific adaptation is important:** Operators design, construct, and operate facilities differently, and there is no one-size-fits-all investigative technique or monitoring plan that can account for facility changes (*e.g.*, equipment that is down) or daily activities. Therefore, deviations from "walking paths" in monitoring plans should be permitted in order to account for unique situations, safety concerns, and unanticipated changes in facility design and construction. **Not all deviations are material**: Deviations from a "master plan" should not require documentation where those deviations are caused by unanticipated events or where those deviations are immaterial. Documenting that an inspector walks towards the left instead of the right because of wind will not mean that the monitoring plan was not followed or was ineffective. Such documentation is only a waste precious resources and time. **Training is the key to a successful program, rather than a specifically defined visual path:** The monitoring plan should focus on training, so that when difficulties or unforeseen events arise, the plan can still be completed successfully. This cannot be done by focusing on a visual path or a delineated walking path; rather, such adaptation requires successful, effective training so that employees know what to look for, where to look for it, and how to address any observed problems.
Photographs of fugitive monitoring activities	EPA has proposed that photographs of fugitive monitoring activities be captured during surveys; such photographs will inherently capture details which would not otherwise be available. Individuals with no interest in fugitive monitoring activities will have interest in viewing photos. However, photographs create security risks to facilities, such as terrorist activities, retaliation, and anti-competitive activities. Oil and gas facilities typically are un-manned and do not have security measures (*e.g.*, fences, gates, and other security measures), further exposing security risks for those whose photographs are made publicly available. In addition, if this requirement is finalized, States and agencies are likely to receive Freedom of Information Act requests for photographs for reasons unrelated to fugitive monitoring. If EPA chooses to require photographs in electronic reporting, then these detailed photographs will be centralized in the public domain for individuals with no interest in fugitive monitoring. Photographs do not provide any additional environmental benefit and should not be required under Quad Oa for fugitive emissions monitoring.