PBPA
PERMIAN BASIN PETROLEUM ASSOCIATION

NMOGA
NEW MEXICO OIL AND GAS ASSOCIATION

IPA NM
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

February 20, 2020

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Directors Ely and Sandoval,

The New Mexico Oil & Gas Association (NMOGA) is a statewide coalition of oil and natural gas stakeholders, individuals, and companies dedicated to promoting the safe and environmentally responsible development of New Mexico's oil and natural gas resources. With more than 1,000 members, NMOGA advocates for sensible and balanced policies for the development, production, and transportation of oil and natural gas, and works to increase the public's awareness and understanding of industry operations and contributions to New Mexico.

The Independent Petroleum Association of New Mexico (IPANM) is the voice of the independent oil and gas producers in New Mexico, and advances and preserves the interests of independent oil and gas producers while educating the public to the importance of oil and gas to the state and all our lives.

The Permian Basin Petroleum Association (PBPA) represents the men and women who work in the oil and gas industry in the Permian Basin of eastern New Mexico and west Texas. Formed in 1961, the PBPA's mission is to promote the safe and responsible development of Permian Basin oil and natural gas resources. The PBPA membership includes some of the largest exploration and service companies with world-wide operations as well as all sizes of independent operators and support companies.

NMOGA, IPANM, and PBPA (the "Associations") commend your agencies and the members of the Methane Advisory Panel for dedicating significant time to developing a technical background document on oil and gas sources of methane. Understanding the sources and potential methane mitigation options is critical to developing policies, regulations, and guidance documents that are science-based, cost-effective, and result in significant methane emissions reductions. Including a broad range of stakeholders in this process has certainly improved the quality of the discussion and the document.

Members of the Associations have undertaken a proactive approach to reduce methane and VOC emissions and capture as much natural gas as possible. Using science, innovation, and collaboration, New Mexico operators worked to prevent waste, reduce emissions, and improve air quality, all while growing production, creating jobs for New Mexicans, and revenues for New Mexico.

The Associations support practical, cost-effective methane and VOC mitigation strategy. Specifically, NMOGA developed strategies for addressing the largest sources of methane in the state, outlined in the Methane Mitigation Roadmap (https://www.nmoga.org/methaneroadmap). We are pleased to see all of the strategies in the Roadmap included in the MAP paper.

The paths forward in the MAP paper contain many worthy suggestions and best operating and design practices. Highly trained engineers work closely with reservoir teams and operations teams to look for and design the best possible solution for each site. Mandating very specific engineering solutions has potential unintended consequences. This limits engineer's ability to adopt new technologies or tailor appropriate approaches for a site. We encourage NMED and OCD to carefully consider the balance between prescriptive measures and flexibility to innovate and appropriately deploy best practices.

In many of the path forward items, there is interest in greater electrification of well pad operations. The Associations support smart solutions, but recognize that access to reliable electricity is a challenge across the state. If solutions are too reliant on reliable electricity, there may be more upset emissions when electricity fails, ultimately increasing total emissions.

We want to work with the agencies on permitting and regulatory mechanisms to support the adoption of a greater suite of solutions. Throughout this comment package, you will find recommendations which could reduce barriers to adopting new solutions, including solutions that exist today and those that may be available in the near future.

In the following pages, we provide comment on many of the paths forward identified in the MAP document. NMOGA, IPANM, and PBPA members have carefully considered each path forward.

Our comments reflect our technical and operational understanding of the various options. We look forward to continuing the discussion with you and your agencies.

Sincerely,

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Executive Director
New Mexico Oil and Gas Association

Jim Winchester
Executive Director
Independent Petroleum Association of New Mexico

Ben Shepperd
President
Permian Basin Petroleum Association

Joint Association Comments

New Mexico Methane Advisory Panel

February 20, 2020

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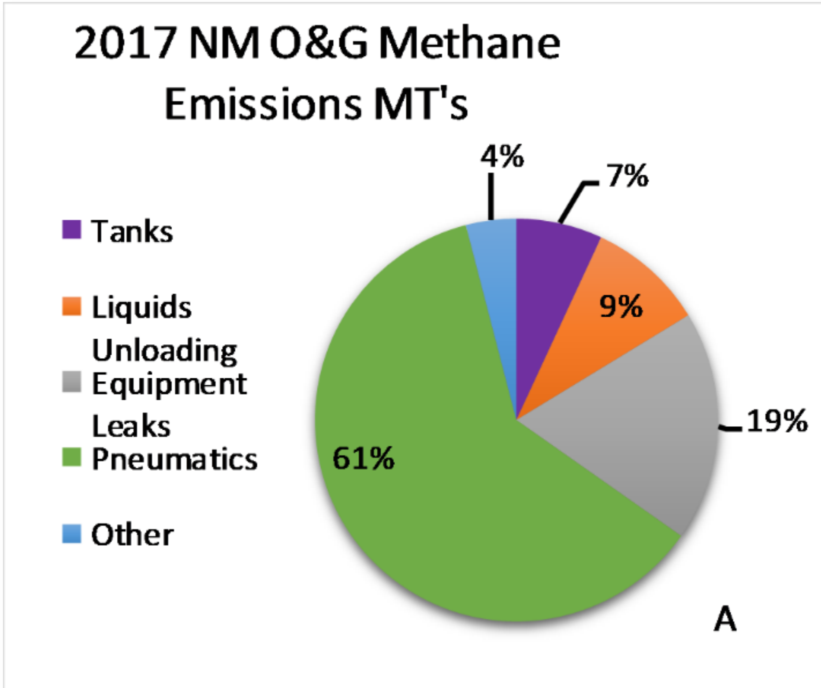
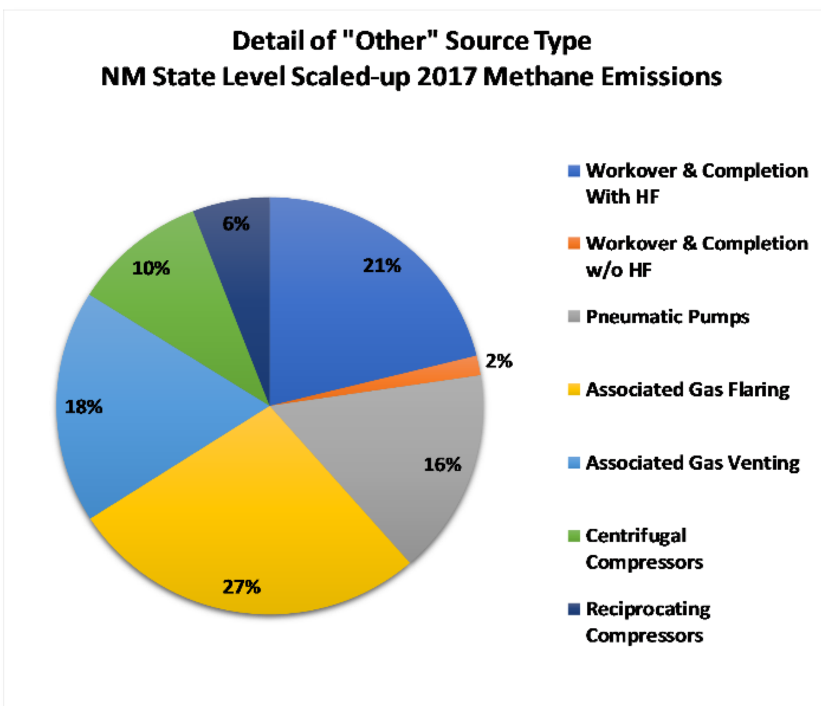
The Associations' Analysis of US EPA Greenhouse Gas Data on Oil and Gas Methane Emissions

Scaled-up 2017 GHGRP Methane Emissions New Mexico Production Segment (Metric Tonnes Methane)			
	Permian	**San Juan**	**New Mexico**
Large Tanks	8,730	211	8,941
Small Tanks	750	4,515	5,264
Tanks	9,480	4,726	14,206
Liquids Unloading	283	18,988	19,271
Equipment Leaks	8,422	29,519	37,941
Pneumatic Controllers	22,360	103,387	125,748
Other	8,260	44	8,304
Workover & Completion With HF	2,591	142	2,733
Workover & Completion w/o HF	6	191	197
Pneumatic Pumps	1,143	917	2,060
Associated Gas Flaring	3,536	0	3,536
Associated Gas Venting	1,868	467	2,335
Centrifugal Compressors	1,318	0	1,318
Reciprocating Compressors	171	586	757
GHGRP Summary Total[1]	48,805	156,665	205,470
Difference[2]	-2,372	-2,259	-4,631

[1]The GHGRP Summary Total is the NM allocated portion of the GHGRP summary methane emissions for the Permian and San Juan basins extracted from the GHGRP flight data.

[2]The difference is the NM allocated GHGRP basin summary total minus the sum of the NM scaled-up sources. It is negative due to the sum of sources shown being greater than the NM allocated GHGRP summary total for the basins. This occurs because some sources can be directly aggregated at the state & basin combination level and hence the sum of sources will not exactly equal the allocated GHGRP basin summary emissions.


2017 NM O&G Methane
Emissions MT's
Tanks
Liquids
Unloading
Equipment
Leaks
Pneumatics
Other
4%
7%
9%
19%
61%
A


Detail of "Other" Source Type
NM State Level Scaled-up 2017 Methane Emissions
Workover & Completion
With HF
Workover & Completion
w/o HF
Pneumatic Pumps
Associated Gas Flaring
Associated Gas Venting
Centrifugal
Compressors
Reciprocating
Compressors
6%
21%
10%
2%
18%
16%
27%

Pneumatics and Pumps

According to the NMOGA analysis of 2017 methane emissions, emissions from pneumatic devices comprise approximately 61% of total methane emissions. Emissions from pneumatic pumps are approximately 1% of total methane emissions.

1.1 Replace or retrofit continuous high bleed pneumatic controllers to low bleed.

The Associations support phasing out of continuous, gas powered, high bleed pneumatic controllers as there are commercially proven, cost-effective alternatives available. Sufficient time (e.g. 3 years) for manufacturers of alternative equipment to stock enough supply is necessary. For some replacement or retrofit activities, it is necessary to conduct such work during a turnaround.

1.2 Replace natural gas with air to actuate pneumatic devices on newly constructed oil wells.

The Associations support this recommendation for new construction of oil well facilities (i.e. centralized tank batteries) that contain multiple controllers with access to reliable power sources. Air systems require air compression and drying equipment, plus new lines to each controller are often not cost effective as retrofits. A typical air system includes a compressor, cooler, separator, air receivers, dryer, and a filtration system. Multiple controllers on one site are required to justify the investment in an air system. In gas fields, the controller counts are generally lower than in oil plays. Air systems are an effective methane emission mitigation solution when reliable power is available. If reliable power is not available, non-pneumatic systems can result in incidents of high emissions if the control system is not available. For example, without a reliable power source, valves could be stuck open resulting in large emissions events. This mitigation solution requires the flexibility to shift back to field gas when electrical systems are down.

1.3 Replace natural gas driven pneumatics with electric actuators/pumps when direct power (line power) is available.

Electric controllers are only appropriate for a limited subset of uses. Pneumatic devices, in most uses, require significant motive force. Actuation response time of electric actuators is inadequate for most uses, which could result in higher emissions from storage tanks. Introduction of electric actuation can result in reliability/control issues due to additional mechanical complexity and would increase the requirements for electricity.

1.4 Replace natural gas driven pneumatics with electric actuators/pumps using solar or on-site generation when grid power is not onsite.

See 1.3 above. In addition to the challenges with electric controllers being unable to replace pneumatic controllers in all cases, solar power adds additional reliability concerns. If controllers lose power, emissions/safety incidents could occur. Since solar power is not reliably available, the cost of any system would need to include battery backup. There are multiple options when designing facilities, and in some cases, solar panels are appropriate (e.g. small chemical injection pumps). Chemical injection pumps move about 2 tablespoons of fluid an hour while a diaphragm pump can move 2,000 gallons. The power needs are very different based on function.

1.5 Where technically feasible and considering safety and back pressure issues, route gas from a diaphragm pump back to a process.

NSPS OOOOa standards require that emissions from new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite (regardless of whether or not it is capable of 95% control), unless it is technically infeasible at sites other than new developments (i.e., greenfield sites). Regulations provide an exemption for pumps that are not in use for more than 90 days per year.

Extending this regulatory requirement to pumps that are not subject to NSPS OOOOa requirement may be feasible only if technical and safety considerations are addressed. Costs for retrofit of existing pumps will also need to be considered.

As discussed in Page 24 of the Methane Advisory Panel report, there are numerous potential safety and operational issues in connecting the discharge from a pneumatic pump to an existing closed vent system and control device such as a flare, combustor, or even a vapor recovery unit (VRU). Control devices are designed for a specific set of conditions including the back pressure that they are capable of handling while continuing to act as a control device. If a pneumatic pump cannot function at a back pressure imposed by a PSV, or other devices operating on the closed vent system, it may not be able to function properly. Similarly, if the control device on a site is located at a distance far away from the pneumatic pump, the gas from the pump may not reach the device and may exert a back pressure rendering the pump ineffective. Thus, a detailed technical analysis will have to be conducted in order to evaluate the technical feasibility of this option.

Cost Analysis

Costs for routing the emissions from a pneumatic pump to a control device are discussed from a VOC emissions perspective in EPA's Control Techniques Guidelines (proposed and subsequently withdrawn for oil and gas sources). In Table 7-4, VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device, EPA indicates that the VOC emission reductions per pump are 0.91 tons for a 2012 annualized cost of $285 and a VOC cost of control of $312/ton of VOCs.

On Page 56626, Vol. 80, No. 181 (September 18, 2015) of the Federal Register notice for the proposed NSPS OOOOa regulation costs for the pneumatic pumps are discussed. EPA estimated for the production segment, the cost of reducing methane emissions for piston pumps to be $395 per ton and the cost of reducing VOC emissions to be $1,420 per ton. For diaphragm pumps, the cost of reducing methane emissions was estimated to be $43 per ton and the cost of reducing VOC emissions was estimated to be $156 per ton.

1.6 LDAR on intermittent bleed pneumatics when not actuating.

The Associations support an annual leak detection and repair program (see Roadmap for full description). During the annual inspections, if utilizing optical gas imaging, we support surveying intermittent bleed pneumatic controllers when they are not actuating. When that controller is not actuating, emissions detected with an optical gas imaging camera would indicate a possible malfunction or leak. The Associations do not support separate LDAR site visits solely to examine intermittent bleed controllers as the devices do not have a high enough potential to emit to warrant a separate site inspection.

Leak Detection and Repair

According to the NMOGA analysis of 2017 methane emissions, emissions from equipment leaks comprise approximately 19% of total methane emissions.

2.1 Annual inspections for existing facilities, avoiding duplication with existing federal programs, such as the LDAR provisions of NSPS OOOOa and NSPS KKK. Low production wells (less than 15 BOEPD) should be excluded. Wellhead only locations should not be included in the LDAR program due to very limited equipment on location, consistent with NSPS OOOOa. Facilities that do not require permits similarly have very limited equipment on location and should be exempt from a LDAR program. Facilities without controlled equipment would not benefit from an LDAR program as a low level of emissions will occur under allowable permit limits with or without an inspection program.

The Associations support this path forward. A recent review of NSPS OOOOa leak survey data indicates that annual inspection frequency is appropriate for non-marginal well sites or facilities. Data from various federal and state and inspection programs, including Colorado, demonstrates that the initial component leak rate from initial inspection surveys shows a significantly lower number of leaks than previously assumed. For example, an American Petroleum Institute analysis of initial NSPS OOOOa inspections showed that only 0.4% of components are found to be leaking during the initial inspection. West Slope Colorado data showed a 0.74% component leak rate for sites with emissions less than 6 tons per year of VOC.

2.2 Quarterly LDAR.

The Associations support the development of a cost-effective LDAR program for existing facilities at an annual frequency, as long as this program avoids duplication with existing federal programs, such as LDAR provisions of NSPS OOOOa and NSPS KKK. A recent review of NSPS OOOOa leak survey data indicates that annual inspection frequency is appropriate for non-marginal well sites or facilitates. Data from various federal and state inspection programs, including Colorado, demonstrates that the initial component leak rate from initial inspection surveys, show a significantly lower number of leaks than previously assumed. For example, an API analysis of initial NSPS OOOOa inspections showed that only 0.4% of the components are found to be leaking during the initial inspection. West Slope Colorado data showed a 0.74% component leak rate for sites with emissions less than 6 tons per year VOC. See 2.1 above.

2.3 Include a robust alternative compliance pathway in rules that would allow operators to request approval to use an alternative leak detection technology method to an IR camera or Method 21.

The Associations support the use of alternative compliance pathways. Specifically, all technology solutions which are capable of achieving emission reductions that are as effective as using an IR camera should be considered. However, we would propose a path forward that allows for emerging technologies to be used without requiring pre-approval. Instead, operators could provide documentation of effectiveness to the agencies upon request. An approach that requires pre-approval will likely cause delays in obtaining these approvals. While industry encourages efforts being made by agencies to fill staff vacancies and attract new employees, it also supports the adoption of other alternatives that will incentivize operators to focus their efforts on reducing the highest emitting sources first and decrease emissions and waste. Willingness to accept/consider alternative technologies that do not require site visits (e.g. aerial reviews or remote monitoring) can also have the added benefits of improving safety and reducing road traffic.

Industry has partnered with academia and NGOs to explore innovative technologies to cost-effectively and accurately locate methane emissions associated with oil and gas locations. Low-cost sensing systems are needed to reduce methane leaks, minimize safety hazards, and promote more efficient use of our domestic resources. Various field tests are being deployed to demonstrate the performance capabilities of such sensing technologies and accelerate commercialization. It is imperative that regulatory agencies unlock the benefits of these emerging technologies by providing a flexible regulatory construct. New Mexico has a unique opportunity to set the stage to encourage adoption of innovative technologies.

Emerging leak detection technologies may lead to variable work practices. For example, sensors flown on aircraft may have a higher leak detection threshold, but will cover a wider geographical area and therefore could be more cost-effective even when conducted at a greater frequency. Enabling new technologies may also require flexibility in work practices, as long as overall emissions reductions are equivalent.

2.4 Use of emissions quantitation technologies during inspections.

If operators are asked to fix all detectable leaks, quantitation is not a critical emission mitigation solution and can wait for technologies to mature. Quantitation itself does not reduce emissions. With currently available technologies, quantitation is not yet accurate and can be very costly. The MAP paper references one specific technology. This technology, and others tested in controlled releases, still show significant error bars in quantification[1] and have not proven to be cost effective. A robust alternative compliance mechanism (see 2.3) will ease the transition to quantitation technologies as they become more effective and accurate. Companies are investing in developing and piloting new technologies that could make these technologies effective in the future.

[1]https://www.elementascience.org/article/10.1525/elementa.373/

Dehydrators

According to the NMOGA analysis of 2017 methane emissions, methane emissions from dehydrators comprise approximately less than 1% of total methane emissions.

3.1 In general, no new controls are necessary for this process due to current control mechanisms.

Dehydrators are already subject to federal air regulations and state permitting requirements (40 CFR 63, Subpart HH and NMED New Source Review). The controls required under these regulations have a co-benefit of reducing methane emissions in process vents. As a result, methane emissions from this source category are very small. Additional regulation of dehydrators is not necessary.

3.2 Require use of zero emissions dehydrators.

A Zero Emission Dehydrator, as described by the EPA, can be misleading since these units still have emissions associated with them. TEG dehydration units are currently regulated under 40 CFR Part 63, Subpart HH (NESHAP MACT HH) standards. Facilities will require reliable electricity in order to properly operate electric driven glycol pumps, which is one of the requirements for a "Zero Emission Dehydrator". Power disruptions would cause the loss of glycol circulation essentially shutting down the dehydration unit. This would result in higher water content in downstream equipment and piping resulting in increased emissions and flaring due to hydrate formations. The Associations believe the rule requirements should not dictate the design of the dehydration units, rather that dehydration units are designed to meet the operational needs/pipeline specifications. Dehydration units should only be required to meet the emission standards applicable under NESHAP MACT HH and NSR permitting.

3.3 Require use of flash tanks, conversion to electric pumps and optimization of circulation rate.

Flash tanks and electric pumps can be an effective way to reduce methane emissions but are not always feasible or reasonable in certain operating situations. Therefore, requiring them for all situations would be impractical. Emission limitations in NSR permitting and requirements under NESHAP MACT HH is sufficient to reduce methane emissions from dehydration units without additional prescriptive control requirements. Optimization of glycol circulation rate is already a requirement for certain dehydration units under NESHAP MACT HH but has limitations at remote, unmanned locations. As stated in section 3.2, power disruptions to electric pumps would cause a loss of glycol circulation, resulting in increased water content in equipment downstream of the dehydration unit. Therefore, we recommend the current requirements.

Compressors and Engines

According to the NMOGA analysis of 2017 methane emissions, methane emissions from reciprocating compressors and centrifugal compressors are each less than 1% of total methane emissions.

4.1 Centrifugal Compressor Wet Seals – Wet Seal Degassing Capture: retrofit wet seal installations with equipment that directs gas from seal oil degassing unit to another use, or flare for destruction.

Methane emissions from centrifugal compressors are less than 1% of total methane emission for existing sources. New centrifugal compressors will have to comply with NSPS OOOOa regulations. Thus additional regulations for existing sources will not contribute to significant methane reductions.

4.2 Centrifugal Compressor Wet Seals- Replacing Wet Seals with Dry Seals.

Methane emissions from centrifugal compressors are less than 1% of total methane emission for existing sources. New centrifugal compressors will have to comply with NSPS OOOOa regulations. Thus additional regulations for existing sources will not contribute to significant methane reductions.

4.3 Reciprocating Compressor Rod Packing – Vapor Capture and route for engine fuel.

In the Federal Register notice dated August 23, 2011 proposing NSPS OOOO regulations, EPA evaluated the possibility of routing vent from reciprocating compressors to control device but did not propose it due to technical considerations. According to EPA, although it is possible to construct an enclosure around the rod packing area and vent the emissions outside for safety purposes, connection to a closed vent system would create back pressure on the leaking gas. This back pressure would cause the leaked gas to be forced inside the crankcase of the engine, which would dilute lubricating oil, causing premature failure of engine bearings, pose an explosion hazard, and eventually be vented from the crankcase breather, defeating the purpose of a control device. The same consideration of a closed vent system would apply to routing the vent from the compressor rod packing to engine for fuel.

Emissions due to reciprocating compressors are only 1% fraction of total methane emissions. Rod packing changes are an adequate means of emission reductions.

4.4 Reciprocating Compressor Rod Packing – Rod Packing Replacement.

NSPS OOOO requires rod packing replacement for reciprocating compressors that are affected facilities. This requirement can be extended to existing facilities that would have been affected facilities but for the date of construction, and for units greater than 100 horsepower that are not subject to other state or federal testing requirements. However, this requirement should not be extended to reciprocating compressors at wellheads. In the Federal Register Notice dated August 23, 2011 regarding proposed NSPS Subpart OOOO regulations, EPA considered the cost-effectiveness of replacing the rod packing for reciprocating compressors at wellheads. According to EPA, reciprocating compressors at wellheads are small and operate at lower pressures, which limit VOC emissions from these sources. Due to the low VOC emissions from these compressors, about 0.044 TPY, combined with an annual cost of approximately $3,700, the cost per ton of VOC reductions is rather high. EPA estimated that the cost effectiveness of controlling wellhead compression is over $84,000 per ton of VOC reduced which is too high and not reasonable.

4.5 Reciprocating Compressors: Annual volumetric measurement of rod-packing venting; repair compressor when emissions exceed threshold level.

This recommendation is based on the California rules. However, even the California rules distinguish between compressors at production facilities and other facilities (including gathering and boosting, transmission, etc.). At production facilities, the rules require leak detection measurement. Volumetric measurement is required only at facilities other than production.

Given that the rod packings at compressors that are subject to the rule will be replaced every three (3) years, it is not clear what incremental benefit is created by volumetric measurement. Measurement may be an option to extend the replacement time if operators choose to do so but should not be required if operators choose to replace rod packing.

Additionally, if the rules require fugitive emissions monitoring, any compressor leaks will also be captured by the emissions monitoring.

Infrastructure

5.1 Statutory/regulatory changes to allow for industry and New Mexico agencies to use third party contractors, who are approved by the State, for surveys and analysis for ROWs and other approvals. This option will help facilitate infrastructure installation.

This type of process is currently utilized by NMOCD to help with the approval of surface waste facilities. The industry participant enters into a contract with a local New Mexico college, selected by NMOCD. The NMOCD creates a scope of work and the necessary report is created by the college. This mechanism helps reduce workload burdens on the agency and helps facilitate a timely approval, while ensuring adequate studies are performed.

Companies require specific permits, rights-of-way, and regulatory approvals before gas capture equipment and transportation infrastructure can be installed. Industry has experienced delays in obtaining these approvals, which may be attributable to a lack of agency resources. While industry encourages efforts being made by agencies to fill staff vacancies and attract new employees, it also supports the adoption of other alternatives such as Option 5.1, which can provide agencies with additional resources.

The Associations believe that the intent of Option 5.1 is to help companies obtain permits, rights-of-way, and regulatory approvals in a timely manner so that equipment and infrastructure can be installed to help reduce emissions. However, if Option 5.1 adds additional approval time, this may counteract the intent and result in even longer delays along with the potential for increased flaring and emissions. If such delays result in no appreciable benefit, this may create disincentives for industry to use this sort of option.

5.2 Reform of PRC statutes to create mandatory deadlines for the approval of electric lines needed to service oil and gas facilities.

The creation of an administrative application process for the PRC to issue timely approvals for electrical lines needed to service oil and gas facilities.

During the MAP meetings, Xcel Energy indicated that PRC approval times for electric lines can run 18 – 24 months. Industry members indicated that they have experienced delays in ability to install electric lines to service oil and gas facilities – particularly in Southeastern New Mexico. Creating mandatory deadlines or a shortened administrative approval process will help facilitate the installation of electric lines.

The Associations support any efficiencies that can be gained at the Public Regulation Commission to facilitate the expedited approval of electric infrastructure buildout.

5.3 A Memorandum of Understanding between BLM, NMSLO, EMNRD, NMED, affected tribes, and BIA regarding ROW and infrastructure coordinated considerations.

This MOU could help the agencies prioritize ROW approvals and discuss the timelines for these approvals. In particular, NMSLO and BLM may be able to work together or better share data to assist with pipeline ROW projects.

The Associations support the various agencies working collaboratively and, to the extent necessary, the sharing of data in order to streamline rights-of-way (ROW) approvals. Efficient ROW approvals will allow for the buildout of necessary infrastructure to mitigate methane emissions.

5.4 Revise gas capture plan (GCP) requirements.

Specify plan elements to include:

- Well location; expected drilling, completion, and first production date; expected volumes and pressures;
- From multiple wells for the above if operator is planning multiple wells in same area within relevant timeframe;
- Information about the operator's other current production, and venting and flaring, in the vicinity of the proposed well;
- Identification of intended gathering system and processing facility for gas production, including pipeline size, pressure, and available capacity now and for the period over which the well is projected to produce, and plan for additional compression if needed;
- Showing/certification that the operator has communicated projected gas volumes and timing for all operations in the vicinity of the destination pipeline to the midstream company, including current venting and flaring;
- Showing/certification that midstream company projects there will be available capacity to accept the projected gas production from the specified well;
- If pipeline capacity not projected to be available, specific plan for alternative gas use/disposal, with demonstration that the operator has the ability to implement such plan (e.g., if plan to reinject gas, show permit applications submitted; if plan to generate for grid, show communications with grid operator, etc.); and,
- Measures to prevent waste over the life of the well, including additional compression and plugging and abandonment.

The Associations support an expansion of the gas capture plan to the extent that additional elements are relevant in mitigating methane emissions. The gas capture plan was made part of the application process through a "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016. The Associations agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance (sometimes 10 to 24 months) of drilling the well and expected production volumes may vary.

5.5 Condition grant of APD on submission of adequate GCP with APD.

The gas capture plan was made part of the application process through a "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016. The Associations support a rule which would require the submission of a gas capture plan to the Oil Conversation Division as a condition for approval of an application for a permit to drill. The Associations agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance of drilling the well and expected production volumes may vary.

5.6 Explore opportunities for sharing information between OCD, NMED, EMNRD, affected tribes, BLM, BIA, and SLO to support permitting and approval processes and achieve methane emissions and waste reductions.

For example:

- SLO could provide information to OCD about lease sales and rights-of-way applications, enabling OCD to anticipate the location and timing of APD, unitization, and spacing applications.
- OCD could provide information to SLO about areas with high venting or flaring rates to consider reorienting leasing to areas with more available takeaway capacity.
- OCD could provide Gas Capture Plan information to NMED about planned venting and flaring during well completion and production testing to monitor for AQ violations.

- NMED could utilize C-115 venting and flaring data to monitor for AQ violations.
- NMED could provide excess emissions data to support OCD verification of C-115 venting and flaring reporting.

The Associations support the sharing of information between governmental entities to allow agencies to make timely permitting decisions in accordance with their statutory authorities which may include emission and waste reductions. It is important for agencies to be efficient in making permitting decisions so that oil and gas revenues can continue to flow to the State. To assist governmental agencies in sharing of information, is the Associations are prepared to provide educational opportunities to agency staff about industry either through written materials or hands on experiences.

5.7 OCD should commission a study of C-129 Applications for Exception to No-Flare Rule to identify the prevalence of operators and wells seeking repeated exemptions for long-term venting or flaring. Follow-up research could look into the causes of long-term venting and flaring.

The Associations recognize the need for proper authorization and accurate reporting regarding venting and flaring volumes and support enhancements to the C-115, C-129, and C-141 applications and reporting processes. The regulated community would benefit from clarity regarding how vented and flared volumes are authorized within each agency, along with additional guidance on reporting. Due to potential inconsistencies in reporting which could be alleviated with additional agency guidance, a study is not needed as the data in its current form does not contain adequate detail to draw any meaningful conclusions or insights.

5.8 OCD should issue a Notice to Operators that have reported long-term volumes of vented gas on C-115 reports requiring them to provide OCD with the reasons for such venting to support possible enforcement action.

The Associations support more detailed reporting of venting and flaring through the C-115 monthly production report, including expanding the number of "Non-Transported Disposition" codes.

5.9 Require that well spacing/density for a given pool be set only after consideration by regulators of surface waste concerns, including by requiring that operators provide estimates of natural gas/methane potentially lost from spacing/density and actions/opportunities to prevent waste (operators already provide estimates of underground reservoir recovery efficiency). Ensures "waste" and methane reduction opportunities are considered by operators before well spacing/density pattern is set across a particular oil or gas pool and provides basis for OCD to determine that changes to well spacing/density to improve underground recovery efficiency do not cause undue or unnecessary surface waste of natural gas. At present, OCC/OCD spacing/density decisions are typically focused on underground reservoir recovery, with surface waste issues given short shrift.

The NMOCD/NMOCC already consider surface waste in their analysis. The concept of "waste" is statutorily defined by the New Mexico Legislature to include both underground waste and surface waste, NMSA 1978, § 70-2-3, and the NMOCD/NMOCC has long embraced a standard of issuing permits and agency orders which promote the prevention of waste.

The issue of well spacing involves a complex reservoir analysis that looks at multiple factors and is reviewed by the OCC/OCD on a case by case basis.

5.10 Strengthen unitization agreement provisions regarding surface waste prevention, including by requiring information regarding the nature and effectiveness of infrastructure to capture and market (versus vent, flare or leak) natural gas and to better synchronize E&P sector development of that unit with midstream operations.

Unit agreements are formed to realize efficiencies in operations. Forming a unit combines leases from one or more lessees allowing for more efficient use of capital, surface use, facilities and production measurement. These agreements enable development over a finite area, in a manner that is appropriate for target formation(s). Generally, fewer facilities are needed when units are approved, thereby reducing potential emission sources.

There are two common types of units, exploratory and enhanced recovery units. They are governed by regulations specific to units and federal and state regulations controlling other facets of oil and gas production. In the case of enhanced recovery units, they allow for more efficient production of residual oil through injection without regard for internal lease boundaries. New unit wells in both exploratory units and enhanced recovery units go through the same review process as non-unit wells and must meet the same standards for approval.

There are no gaps in regulatory programs unique to units. Unit agreements do not preclude or limit enforcement of updated regulations as changes are made. The appropriate mechanism to prompt communication between producing and midstream companies, to minimize methane emissions, is the Gas Capture Plan. The Gas Capture Plan is required for both unit and non-unit new drill and recompletion activities. Addressing resource waste in unit agreements would be redundant and would not further the goal to minimize waste. Rather, it could be seen as a dis-incentive to unitization and could have unintended restrictive consequences.

5.11 Comprehensive Drilling Plans/Master Development Plans/Geographic Area Plans. These would be mandated for all foreseeable oil & gas infrastructure, ensuring that regulators are afforded a more expansive picture of field-level development and avoid piecemeal review and approvals. These Plans should also be used to assess opportunities to retrofit existing infrastructure that results in vented/flared/leaked natural gas as a condition of approving new infrastructure and ensuring that new, high-pressure wells do not “knock off” existing, lower-pressure wells within the same field. Such plans should be designed as

opportunities for multi-jurisdictional engagement by OCD, SLO, BLM, and NMED.

Members of the Associations already aim to comprehensively plan their development and are taking a broader approach to oil and gas planning and permitting.

5.12 Consider more pipeline integrity strategies including iPipe.

iPipe (intelligent pipeline integrity program) is an industry-led consortium whose focus is to contribute to the advancement of near-commercial, emerging technologies to prevent and detect gathering pipeline leaks. The program is a direct response to North Dakota Governor Burgum's May 2017 challenge to industry to think outside the box and apply new technology to address the challenge of eliminating pipeline leaks.

The Associations support technologies that prevent and detect gathering line leaks. It's important to note the value of voluntary programs which can complement effective regulatory efforts leading to a reduction in emissions.

5.13 Work towards providing more grid power through master development plans, faster right of way acquisition for oil and gas and utility providers.

The Associations support any efficiencies that can be gained in the permitting and approval process to facilitate the expedited approval of electric infrastructure buildout.

5.14 Consider streamline permit for power generation.

The Associations support streamlined or standardized permitting options for technologies, such as onsite power generation, in order to mitigate methane emissions, including the ability to relocate permits for temporary events.

5.15 Portable flares for pipeline blowdowns.

The Associations support a streamlined permitting process for the use of temporary and/or portable flares during pipeline maintenance activities.

5.16 Reduce pigging emissions

Pigging is a necessary maintenance procedure to manage liquids buildup, maintaining gas flow, and operational integrity of the gathering pipelines. The Associations support and encourage the use of best practices for pigging to minimize emissions when feasible and practicable.

5.17 Reduce blowdown emissions

The Associations support and encourages the use of best practices when feasible and practicable for equipment blowdowns to minimize methane emissions. In many cases, blowdown emissions are authorized as part of a state issued air permit.

Flaring and Venting

According to the NMOGA analysis of 2017 methane emissions, emissions from flaring are approximately 2% of total methane emissions. Emissions associated with venting are approximately 1% of total methane emissions.

6.1 More detailed reporting on C-115 form (production report).

The Associations support a reasonable increase in detailed reporting of venting and flaring through the C-115 monthly production report, including expanding the number of "Non-Transported Disposition" codes, and would request there be a grace period for operators to update their coding systems. Producers need time to update and test their accounting software, which can take several months or more to change.

6.2 Establishing requirement to submit Gas Capture Plan with APD through rulemaking.

The gas capture plan was made part of the application process through a "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016. The Associations support a rule which would require the submission of a gas capture plan to the Oil Conversation Division as a condition for approval of an application for a permit to drill. The Associations agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance of drilling the well and expected production volumes may vary.

6.3 Operators do not vent when gas can be flared instead.

The Associations recognize the benefits of flaring associated gas rather than venting as a way of mitigating methane emissions. We support minimizing the volume of gas vented when flaring the gas would be technically infeasible, such as when the gas is not readily combustible, the volumes are too small to flare, or venting would be necessary for safety reasons. Furthermore, the OCD requires gas to be flared rather than vented when pending a connection to a gas-gathering facility. 19.15.18.12.F NMAC.

6.4 Operators engage with midstream in more active development planning (Addressed in MAP infrastructure planning report).

The Association support a rule which would require the submission of a gas capture plan to the Oil Conversation Division as a condition for approval of an application for a permit to drill. We agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance of drilling the well and expected production volumes may vary.

6.5 Current regulation (19.15.18.12A NMAC) prohibits an operator from flaring or venting casinghead gas produced from a well after 60 days of the well's completion. Provided the exception process is better defined and includes a notice provision, a reduction to 30 days from the 60 days currently authorized is proposed.

Current regulation (19.15.18.12A NMAC) prohibits an operator from flaring or venting casinghead gas produced from a well after 60 days of the well's completion. The Associations support a reduction to 30 days from the 60 days currently authorized so long as the exceptions to the prohibition are better defined, acknowledging that flaring is acceptable in certain circumstances (i.e., scheduled and non-scheduled maintenance, emergencies, facility malfunctions). As stated previously, the Associations recognizes the benefits of flaring associated gas rather than venting it as a way of mitigating methane emissions and support minimizing the volume of gas vented unless flaring the gas would be technically infeasible.

6.6 Auto igniters for new flares.

The Associations recognize the benefits of flaring associated gas rather than venting as a way of mitigating methane emissions and support minimizing the volume of gas vented unless flaring the gas would be technically infeasible, such as when the gas is not readily combustible, the volumes are too small to flare, or venting would be necessary for safety reasons. We support a requirement that new flares be equipped with a continuous pilot flame or automatic ignition system which automatically attempts to relight the flare at the tip, ensuring it is lit when gas streams are present. This will minimize the chance that a flare remains unlit should the pilot flame be extinguished due to wind or other adverse weather conditions.

6.7 Ensure that all venting and flaring from oil and gas production and gathering upstream of the processing plant is reported on a monthly basis, consistent with clear standards, and made publicly available online.

Clarify that C-115 (or another appropriate form) should include venting and flaring that occurs:

- Due to lack of connection with a pipeline;
- During completions/recompletions, including during initial flowback;
- In response to upsets, disruptions, capacity constraints anywhere in the system;
- In the course of maintenance activities;
- From operation of pneumatics, tank vapors, and flaring of such vapors (note that BLM considers these volumes unavoidable lost or beneficial use. Also, low pressure flaring is out of scope for this report. It is discussed in tanks.);

- Each of operator's temporarily abandoned well, if venting occurs; and
- Any other sources of venting and flaring that can be measured or estimated.
- Adopt third-party audit or verification program to ensure that operators are complying with reporting requirements (given past high levels of non-compliance and also compliance with the exception criteria).

The Associations support more detailed reporting of venting and flaring through the C-115 monthly production report, including expanding the number of "Non-Transported Disposition" codes and appropriately defined circumstances where venting or flaring is necessary. Further, we support clarification that the C-115 form is for production reporting in the segment of the industry upstream of the midstream segment and, to the extent venting and flaring is mandated under another federal or state environmental regulatory program such as NSPS OOOOa or state issued air quality permit, it should not be reported here. The Associations recognize that regulatory agencies possess the proper statutory authority to ensure compliance with all reporting requirements.

6.8 Include, in reporting specifications, standards for measurement and/or highly reliable estimation approaches based on measurement of other known variables, such as oil production volumes and frequent (e.g., monthly) measurements of gas-to-oil ratio.

The Associations recognize the need for accurate accounting and reporting of flared volumes to ensure consistent, reliable data is available to the state. The reporting requirements in 19.15.18.12.F NMAC should include a protocol for high pressure flaring and approved standards for estimating and measuring flared gas. We support the development of a such a protocol that clarifies the standards for which flared associated gas is measured or estimated.

6.9 Require use of reliable tools for measuring or estimating flared volumes; require regulatory oversight of purchase and calibration of measurement tools (Note: OCD has no authority over purchasing of

equipment and BLM requires use of approved equipment under the new measurement rules).

The Associations recognize the need for accurate accounting and reporting of flared volumes to the state. Operators are already required to adhere to established measurement standards as published by API and adopted by the BLM. The state's focus should remain on limiting emissions and not overseeing purchases which operators are better suited for because of expertise.

6.10 Establish electronic reporting system for all sources of venting and flaring (e.g., including C-129s and C-141s) upstream of processing plants and make results publicly available online. Note that C-129s are submitted by operators as a "just in case" and volumes are estimated. C-141s are after-the-fact and volumes reported as a non-transported disposition code "L" for lost. Therefore, any actual volumes are reported on C-115s. See "enhanced reporting and measurement protocols."

The Associations recognizes the need for accurate reporting regarding venting and flaring volumes and support enhancements to C-115, C-129, C-141 applications and reporting processes. It should be noted that the C-129 form reflects estimated or expected volumes and flaring duration, not actuals.

6.11 Condition grant of APD on submission of adequate Gas Capture Plan with APD.

The gas capture plan was made part of the application process through a "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016. The Associations support a rule which would require the submission of a gas capture plan to the Oil Conversation Division as a condition for approval of an application for a permit to drill. We agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance of drilling the well and expected production volumes may vary.

6.12 Specify gas capture plan elements to include.

- Well location; expected drilling, completion, and first production date; expected volumes and pressures;
- From multiple wells for the above if operator is planning multiple wells in same area within relevant timeframe;
- Information about the operator's other current production, and venting and flaring, in the vicinity of the proposed well;
- Identification of intended gathering system and processing facility for gas production, including pipeline size, pressure, and available capacity now and for the period over which the well is projected to produce, and plan for additional compression if needed;
- Showing/certification that the operator has communicated projected gas volumes and timing for all operations in the vicinity of the destination pipeline to the midstream company, including current venting and flaring;
- Showing/certification that midstream company projects there will be available capacity to accept the projected gas production from the specified well;
- If pipeline capacity not projected to be available, specific plan for alternative gas use/disposal, with demonstration that the operator has the ability to implement such plan (e.g., if plan to reinject gas, show permit applications submitted; if plan to generate for grid, show communications with grid operator, etc.); and,
- Measures to prevent waste over the life of the well, including additional compression and operator elected proper plugging and abandonment to avoid the rare instance of orphan well venting scenarios.

The Associations support an expansion of the gas capture plan to the extent that additional elements are relevant in mitigating methane emissions. The gas capture plan was made part of the application process through a "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016.

The Associations agree that a plan should be required and made part of NMAC 19.15.14.8 – Permit to Drill, Deepen, or Plug Back, thus requiring the operator and pipeline company to more formally plan for projected volumes and schedules ahead of drilling. Although the gas capture plan includes the best available information at the time of submittal, it should be noted that it is often submitted well in advance of drilling the well and expected production volumes may vary.

6.13 Define "undue hardships" (e.g. maintenance, emergencies) as per 19.15.18.12.B NMAC while maintaining the ability to apply for an exception.

The Associations support further defining "undue hardships" along with enhancements to the C-129 application process provided that exceptions to the prohibition are better defined, acknowledging that flaring is acceptable in certain circumstances (i.e., scheduled and non-scheduled maintenance, emergencies, facility malfunctions). This would provide clarity and certainty to both industry and the agency allowing for better-informed decision making regarding venting and flaring events.

6.14 Prohibit operators from venting whenever gas can be flared instead; i.e., only allow venting when flaring is not possible as a technical matter or where flaring is prohibited due, e.g., to wildfire risk. Note that both the BLM and OCD have rules requiring flaring rather than venting. See page 162 for BLM rule §3179.6(b) and page 163 for NMOCD rule 19.15.18.12.F.

The Associations recognize the benefits of flaring associated gas rather than venting it as a way of mitigating methane emissions. We support minimizing the volume of gas vented when flaring the gas would be technically infeasible, such as when the gas is not readily combustible, the volumes are too small to flare, or venting would be necessary for safety reasons.

6.15 Adopt performance standard for new and existing flares to ensure high destruction removal efficiency (minimum 98%) and continuous burning pilots.

The Associations recognize the benefits of flaring associated gas rather than venting it as a way of mitigating methane emissions and support minimizing the volume of gas vented when flaring the gas would be technically infeasible, such as when the gas is not readily combustible, the volumes are too small to flare, or venting would be necessary for safety reasons. We support a requirement that new flares be equipped with a continuous pilot flame or automatic ignition system which automatically attempts to relight the flare at the tip, ensuring it is lit when gas streams are present. This will minimize the chance that a flare remains unlit should the pilot flame be extinguished due to wind or other adverse weather conditions.

6.16 Set overall limit (with no exceptions for specific activities/circumstances) on the gas flared by each operator. Limit could take the form of a minimum percentage and/or volume of total gas production from the operator in the State that must be captured. If apply sufficiently stringent overall percentage limits, could potentially allow for a limited volume of flaring/well on average over all of an operator's wells (note that C-115s are required to be submitted the 15th day of the second month following the month of production, therefore, an average will not be based on most current volumes) that may be deducted from the capture percentage compliance calculation (in lieu of requiring burdensome case-by-case requests and approvals for emergencies, maintenance, and force-majeure events etc.), and ratchet that deductible volume down over time, giving operators an incentive and opportunity to fine-tune operations to reduce such events.

The Associations support more detailed reporting of venting and flaring through the C-115 monthly production report, including expanding the number of "Non-Transported Disposition" codes, and believes it is premature to pursue limits as significant challenges continue to exist in the implementation of such limits in other jurisdictions.

6.17 Establish automatic consequences for failure to meet capture percentage standards. E.g., set a meaningful fee per mcf gas flared/vented in contravention of applicable capture standard, due upon notice of exceedance; and/or require operator to be in compliance with capture percentage standard as a pre-condition for issuance of any new APD for such operator. Ensure flaring policy is enforceable and penalties sufficient to outweigh financial incentives to flare rather than capture.

The Associations support more detailed reporting of venting and flaring through the C-115 monthly production report, including expanding the number of "Non-Transported Disposition" codes, and believes it is premature to pursue limits as significant challenges continue to exist in the implementation of such limits in other jurisdictions.

6.18 Assess severance tax and royalties on all gas produced rather than only on gas produced or sold.

The implementation of Option 6.18 would involve complex changes to existing New Mexico law. Royalties are governed by the terms of an oil and gas lease. "In New Mexico the language of the State oil and gas leases is prescribed by statute. Over the years, the Legislature has enacted several versions of the statutory oil and gas lease, and Lessees have entered into 'hundreds' of oil and gas leases with the State." (2013-NMSC-009, ¶ 2, 299 P.3d 844, 847. These lease agreements are contracts between the State as lessor and the lessee. Harvey E. Yates Co. v. Powell, 98 F.3d 1222, 1229–30 (10th Cir. 1996). The terms of these statutory lease agreement forms determine how and when royalties must be paid on gas produced. Current lease rights cannot be impaired by the State without resulting in potential claims for breach of contract or running afoul of the New Mexico Constitution and changes made to future lease forms will require legislation.

The implementation of the option proposed in 6.18 may also require reforms made to the Oil and Gas Severance Tax Act and/or the promulgation of regulations by the Taxation and Revenue Department. Generally, oil and gas severance taxes are assessed on production that is severed from the soil and sold. § 49:34, Production and severance taxes on oil and gas—New Mexico, 4 Summers Oil and Gas § 49:34 (3d ed.). As a result, the Associations believe that the implementation of this option will involve several complex legislative and legal issues.

6.19 Prohibit flaring unless permitted by OCD. Only permit flaring required for specific delineated circumstances (e.g., safety emergencies, unplanned infrastructure maintenance, upset conditions, etc.). Permit would specify volume and/or time limit. Consider exempting defined de minimis amount of flaring from permit requirement. Monitor to avoid repeat exemptions and long-term flaring.

The Associations recognize the need for proper authorization and accurate reporting regarding venting and flaring volumes and support enhancements to C-115, C-129, and C-141 application and reporting processes. The regulated community would benefit from clarity regarding how vented and flared volumes are authorized within each agency. It should be noted that the C-129 form reflects estimated or expected volumes and flaring duration, not actuals.

6.20 Create permitting options for some of the more recent reinjection solutions that have been presented to NMOCD.

The Associations support the expansion and streamlining of permitting options for innovative reinjection solutions as an alternative to flaring.

6.21 Approve alternative technology by more streamlined NMED permitting process.

The Associations support streamlined or standardized permitting options for proven alternative technologies to mitigate methane emissions, including the ability to relocate permits for temporary events.

6.22 Clarify the definition of waste in venting/flaring regardless of whether or not it is an authorized exemption.

The Associations generally support clarification of the definition of waste within regulations properly promulgated by the New Mexico Oil Conservation Commission. Such clarification could help create certainty for the regulated community.

6.23 Ability to amend C-115 by line to ensure accurate reporting/ability to amend reports vs. requiring a company's statewide C-115 production to be re-submitted.

The Associations understand the need to ensure accurate reporting and support the ability to submit amended C-115 reports as a way to streamline the reporting process.

Workovers and Liquids Unloading

According to the NMOGA analysis of 2017 methane emissions, emissions from liquids unloading are approximately 9% of total methane emissions. Emissions from workovers are approximately 1% of total methane emissions.

7.1 Create differential pressure to eliminate the need to vent a well to unload.

Operators always aim to avoid liquids unloading; however, it is inevitable in the lifecycle of a gas well. Managing wellbore liquid build-up in wells is fundamental to maintaining production, avoiding early abandonment of wells, and maximizing resource recovery. Gas well unloading is a complex field of engineering where a large number of different technologies, tools, and practices are matched to individual well characteristics at each stage of its lifecycle to most efficiently manage liquids and maintain production. Differential pressure can be achieved through intermitting, installing smaller diameter tubing string, or using surfactants or foaming agents. The method selected is highly dependent on well characteristics.

7.2 As a best management practice, minimize volume vented for manual liquid unloading events by lowering the wellhead pressure:

The best management practice of reducing the wellhead pressure to minimize the volume vented is more applicable to workover preparations than liquid unloading. The practice of unloading liquids from a well requires that a pressure differential be created that is significant enough to allow liquids to be purged from the wellbore. The routing of initial volume of gas to the sales line could make the liquid unloading less effective and requiring more attempts to unload the well. The additional attempts would ultimately lead to a larger volume of gas being vented through the liquids unloading process.

7.3 As a best management practice, monitor manual venting onsite, in close proximity or via remote telemetry.

The Associations support this as a best management practice. Monitoring of manual (non-automated) liquids unloading assures that any required venting is minimized. As soon as the appropriate differential pressure is achieved, the venting operation can be shut down and the well returned to production.

7.4 As a best management practice, minimize venting for workovers by lowering the wellhead pressure as much as possible prior to a blowdown:

The best management practices (BMPs) mentioned throughout the Methane Advisory Panel Technical Report need to be considered as possible guidance for achieving methane emission reductions in the Oil & Gas Sector and not as regulation. The application of best management practices is very dependent on well site conditions, equipment availability, and infrastructure configurations. To provide flexibility within the methane reduction regulatory framework, it would be best served to create guidance documents based on the BMPs provided in each section of the technical report.

7.5 As a best management practice, consider the lowest emitting liquids unloading option between (1) artificial lift, including plunger lifts, and (2) supervised manual unloading. Verify the option is technically feasible and implement that option for liquids unloading at the facility.

The application of artificial list should not be considered a control technology. The deployment of artificial lift is an engineered solution that is specific to the site and well conditions. The misapplication of artificial lift could result in an overall increase in emissions from a well site. The operator selects the appropriate artificial lift method based on the well conditions, production targets, and individual well economics. Prescribing artificial lift installations to reduce methane emissions could also have a detrimental effect in terms of resource recovery. If the individual well economics do not support the installation of a prescribed artificial lift method, the operator would choose to plug and abandon the well. This premature abandonment would leave oil and gas reserves in the ground and could be considered a waste of the resource.

7.6 Establish a liquids unloading emissions limit (e.g., emissions per event, emissions per facility, or some combination thereof).

The establishment of a liquids unloading limit could lead to the premature abandonment of many marginal gas wells. In many cases the need for liquids unloading activities are toward the later part of a well's life cycle. The liquids unloading occurs when gas velocity in the tubing is no longer sufficient to lift liquids out of the wellbore. This low velocity is usually due to a lower production rate from the well. These lower rate producers are in a marginal well category. It is imperative that the impact of additional regulatory burden be considered on marginal wells. The over burdening of marginal wells will negatively impact the state and local economies as the marginal wells will likely be plugged and abandoned. If the wells are plugged and abandoned, the tax and royalty revenues would no longer be generated. In addition, the jobs associated with operating these marginal wells would be lost.

Separators, Storage Vessels

According to the NMOGA analysis of 2017 methane emissions, emissions from storage tanks are approximately 7% of total methane emissions.

8.1 Applicability threshold.

The Associations support controlling existing storage vessels not subject to NSPS OOOO/OOOOa as long as there is an appropriate applicability threshold and the operator determines the appropriate control for each applicable site. The American Petroleum Institute's December 4, 2015 comments to EPA on the Draft Control Techniques Guidelines demonstrated that 15 tons per year (tpy) of VOC would be a cost effective applicability threshold for controlling existing storage vessels.[1] The Associations agree this is the appropriate applicability threshold.

It is not cost effective to control existing storage vessels where the vessel has a potential emission rate less than 15 tpy of VOC. To support NSPS OOOO, EPA determined a control device's cost effectiveness depends on the amount of vapor produced by the controlled storage vessel, which in turn depends on a storage vessel's throughput.[2] The storage vessel must have a sufficient throughput to justify the installation of the control device.

Properly installing a control device requires performing a site-specific layered analysis to ensure the facility operates safely and effectively with the control. It is highly likely this analysis would find that retrofitting an existing storage vessel with a control device requires significant facility modifications (e.g. pipe sizing and configuration, telemetry, pressure transmitters, backpressure devices etc.). This analysis, and the design requirements to safely and properly install a control device, can be incorporated into a new facility more efficiently than an existing facility. Therefore, there should be a higher applicability threshold to install a control device for existing storage vessels than the threshold set by NSPS OOOO/OOOOa for existing sources. A threshold of 15 tpy of VOC ensures the storage vessel's throughput supports a cost-effective project to retrofit the facility with a control device.

A lower threshold, or specifically requiring a vapor recovery unit (VRU), to control existing storage vessels could incentivize operators to shut-in or plug and abandon wells at an accelerated pace. In either case, it could be more cost effective for operators to abandon resource recovery rather than to analyze, upgrade, and retrofit existing low producing facilities. While a VRU can be effective for facilities producing high volumes of oil and gas, VRUs are not appropriate at all facilities. It would not be cost effective to install a VRU at a facility lacking a reliable power source or for a storage vessel below the 15 tons per year of VOC threshold.

The Associations do not support waste from unrecovered resources. A rule to control existing storage vessels should set an applicability threshold of 15 tons per year of VOC and should allow operators to determine the appropriate control device for each applicable facility.

[1]American Petroleum Institute, Comment Letter on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry (Dec. 4, 2015), https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0216-0157.

[2]Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 163 (Aug. 23, 2011), https://www.govinfo.gov/content/pkg/FR-2011-08-23/pdf/2011-19899.pdf.

8.2 Controls – VCUs and VRUs: Consider incorporating VCUs and VRUs into facility design to capture additional "flash gas" not captured by separator, especially early in the well life when production is highest.

When the quantity and quality of gas available is appropriate and the facility design supports it, vapor combustion units (VCUs) are effective control devices and VRUs can be effective as process equipment or as a control device. Over an appropriate threshold (see 8.1) VCUs, VRUs and other control strategies should be considered in facility design, and operators should analyze and design facilities to control emissions from tanks above a threshold.

8.3 Separators/VRTs: Optimize separator design/operating parameters to maximize gas separation. Consider use of VRT after the separator as a second opportunity to minimize "flashing" in the storage tanks.

See 8.2 above.

Although the majority of the gas is removed from the liquids during the separation process, the Associations do support controlling emissions when a sufficient quantity of gas is available. This can be done by utilizing efficient and cost-effective control technologies such as vapor recovery units (VRU), vapor recovery towers (VRT), vapor combustion units (VCU) and/or other control technologies to minimize and eliminate pollutants. The Associations recommend allowing operators the ability to exercise flexibility when designing facilities and selecting control technologies above an emissions threshold (see 8.1).

8.4 Inclusion of controlled tanks and relief devices in site specific LDAR.

The Associations support the inclusion of controlled tanks and relief devices in site specific LDAR (see LDAR section above). To avoid duplicative requirements, operators should not be required to conduct LDAR monitoring efforts for controlled tanks and relief devices, if conducting monitoring for that equipment is already mandated by other regulatory LDAR requirements. It should be noted that many existing storage tanks are currently subject to monitoring under NSPS OOOO/OOOOa. Additionally, in New Mexico, the enforceable state program (GCP Oil and Gas) allows operators for emissions reductions processes when calculating potential to emit to determine NSPS OOOO/OOOOa applicability for new storage vessels. EPA expressly allows for operators to account for enforceable limitations under state programs to prevent operators from being subject to duplicative requirements under state and federal law.

8.5 Control storage tanks with emissions above specified thresholds (e.g. 10 tpy of CH_4 or 2 tpy of VOCs) by 98%.

See 8.1 above.

The Associations support the control of storage tanks emissions above 15 tons per year (tpy). As stated in Section 8.1 of the comments, we support controlling existing storage vessels not subject to NSPS OOOO/OOOOa as long as there is an appropriate applicability threshold and the operator determines the appropriate control for each applicable site. The American Petroleum Institute's December 4, 2015 comments to EPA on the Draft Control Techniques Guidelines demonstrated that 15 tons per year (tpy) of VOC would be a cost-effective applicability threshold for controlling existing storage vessels. The Associations agree this is the appropriate applicability threshold.

8.6 Require operators to route tank emission to VRU unless technically infeasible.

See 8.1 above.

The Associations support routing tank emissions to a vapor recovery unit (VRU) where technically feasible above an appropriate threshold. As stated in Section 8.1 of these comments, we support controlling existing storage vessels not subject to NSPS OOOO/OOOOa as long as there is an appropriate applicability threshold and the operator determines the appropriate control for each applicable site.

The Associations agree with utilizing VRUs to control tank emissions; however, we recommend the flexibility to utilize other alternative design or control technologies which similarly reduce emissions.

Many existing storage tanks at older facilities were not designed for utilizing control devices as it can result in inherent safety risks by compromising tank integrity and causing tank pressurization.

8.7 Require operators to use automated tank gauges to reduce fugitive emissions from thief hatches.

Automatic tank gauges are a technology that has several benefits, including safety benefits from reducing work at heights. However, there are several considerations and it does not eliminate the need to open thief hatches. BLM approval is required for automatic tank gauging. Retrofit costs need to be considered for all existing storage vessels. Uncontrolled tanks and those that have very low throughput and limited gauging would have little to no reduction potential. Even with automatic gauging, operators still need to open hatches to calibrate, maintain, and inspect gauges.

The Associations suggest the economic, operational practicality, and technical feasibility of replacing and retrofitting existing storage vessels with automated tank gauges be further evaluated.

8.8 Require operators to control emissions during unloading of emissions from tanks into trucks.

The Associations support appropriate control measures during truck loading operations but recommends considering alternative thresholds and/or limits, such as throughput volumes. For example, Texas has truck loading requirements limiting throughput to 20,000 gallons day over a 30-day period. In many cases, operators would be transporting products by truck only as an alternative measure and not as the normal mode of operation. Therefore, under upset conditions, exemptions from control measures would need to be made available. There are several engineering concerns to be considered in any cost-effective analysis including potentially installing vapor destruction/combustion units if one is not on site. The location of the VRU on site (before or after tanks) could limit ability to use a VRU to control emissions from loading.

8.9 Convert water tank blanket from natural gas to produced CO2 gas.

This requires a supply of CO2 rich gas on site. Therefore, this methane mitigation solution would only be applicable in very limited settings.

8.10 Recover gas during condensate loading.

See 8.8 above.

8.11 Install pressurized storage of condensate.

Pressurized storage will likely cause operators to be unable to meet product specifications.

8.12 Apply control thresholds to tank emissions from all tanks located at a facility, rather than individual tanks or individual tanks manifolded together.

The Associations support applying thresholds to the individual tanks located at a facility, rather than collection of tanks. This application is consistent to the tank emission thresholds in NSPS OOOO/OOOOa.

8.13 Consider installation of remote monitoring to notify/control critical controllers or components, such as malfunctioning dump valves or open thief hatches.

Remote monitoring technology can be a valuable tool to monitor operational parameters. It is unclear how robust today's technologies are to control malfunctioning dump valves or open thief hatches. The remote monitoring technologies utilized today are not intended for these purposes.

8.14 Consideration of a control credit similar to TCEQ program.

The Associations support programs which incentivize methane emission reductions. Any incentive programs should be technology and vendor neutral.

8.15 Install enhanced vapor recovery in addition to a VRU system.

Design of facility should include technological flexibility, and not be reliant on one particular technology. The particular technology cited can help widen the operating envelope if oxygen is a concern. There are other ways to achieve the same goal, and other concerns beyond oxygen which can lead to flaring.

The Association support the utilization of a vapor recovery unit (VRU) system to minimize and reduce methane emissions. However, maximum technology flexibility should be afforded to owners and operators. Therefore, a requirement to install a particular control technology should be avoided.

Completions and Stimulations

According to the NMOGA analysis of 2017 methane emissions, emissions from completions are approximately 1% of total methane emissions.

9.1 Existing federal NSPS requirements adequately address the completion activities in New Mexico.

Completions of gas wells and oil wells are sufficiently covered by NSPS OOOO and NSPS OOOOa.

9.2 Codify existing federal regulations to protect against possible rollback.

EPA's proposals to make revisions to NSPS OOOO/OOOOa have no proposed changes to the completions requirements.

9.3 Eliminate "Technical Infeasibility" exemption where infeasibility could have been recognized in advance.

NSPS Subpart OOOOa allows operators to obtain an exemption from green completion requirements on technical infeasibility grounds even when the grounds for the exemption (e.g., lack of gathering lines) are known in advance.[4] In adopting this rule, EPA considered but rejected comments urging the agency to disallow technical infeasibility exemptions in these cases. The agency also considered but rejected comments suggesting that the agency require advanced notification of an operator's decision to invoke technical infeasibility.

Wells may be connected to pipeline but may still need to flare due to capacity or pressure issues. There are technical infeasibilities that arise even when capture options have been planned, making the need to flare difficult to predict ahead of time. Abrupt shut-ins or restricted well flow can cause formation damage to wells and result in underground waste. In some cases, technical infeasibility issues can come up very late in the process despite operator plans to connect to a gathering line and to route the gas to sales. For example, pipelines may have operational issues on the day of the completion activity. Or there may be a right-of-way issue that prevents a pipeline connection at the last minute. Or the gas quality may prevent routing the gas into gas pipeline. There can be unforeseen circumstances which cannot be predicted in advance. Any methane mitigation solution needs to make provisions for unforeseen and unpredictable circumstances despite advanced planning.

The proposal to eliminate technical infeasibility options will simply create uncertainty around what could and could not have been recognized in advance without adding practical value to implementation of the rule. Regardless of advances in agency resources or other measures, there needs to be a mechanism for operators to make adjustments during unpredictable circumstances.

[4] See 81 FR 35852

9.4 New Mexico state rule that contains the following components for all completions, re-completions and stimulations: Provide notice prior to completion/recompletion/stimulation (required).

See 9.3.

9.5 New Mexico state rule that contains the following components for all completions, re-completions and stimulations: no venting exceptions during completions/recompletions/stimulations.

See 9.3.

9.6 New Mexico state rule that contains the following components for all completions, re-completions and stimulations: limit technical feasibility exceptions for flaring within volumetric limitations.

See 9.3.

Cross-Cutting Issues

10.1 Comprehensively improve methane emissions reporting.

We support collecting better data but must recognize that data collection can be expensive and does not reduce emissions. Newer technologies are under development but are not directly comparable to the EPA's Mandatory Greenhouse Gas Reporting Program (GHGRP) or other reporting programs.

10.4 Well-site electrification: incentives for utility co-ops.

The Associations support increased access to reliable sources of electricity.

10.7 Exempt stripper wells.

The Associations support exempting wells with low production and emissions.

10.8 MOU between state agencies to :1) speed the development of electrical infrastructure to the oilfield; 2) willingness of electrical utilities to accept and manage distributed generation put onto the grid from oilfield sites. Impacts suggestions: conversion of pneumatic controllers, compressors, etc. to electrical power. Use of available associated gas for onsite generation.

The Associations support increased access to reliable sources of electricity.

10.14 Add more detail to the New Mexico Civil Penalty Policy – Appendix D using the Texas Environmental, Health and Safety Audit Privilege Act (both TCEQ and RRC have adopted this program) as a foundation.

The Associations support this proposal, which would likely require legislation. Similar legislation has been an effective model that is also in place in Oklahoma and Colorado.

10.15 Temporary (<1 year on site) gen set power allowed to be placed on site in the event line power is not available without forcing NMED permitting staff to write permit for this temporary requirement and required company to wait up to 120 for this permit modification – with this timing sometimes forcing flaring while waiting on gen set power

The Associations support streamlined processes as this would provide an immediate tool to reduce emissions from flaring. Any beneficial use technology temporarily on site should have streamlined, flexible permitting.

10.16 Increase FTE count and funding at OCD and NMED AQB in order to more effectively implement and enforce methane reduction regulations.

The Associations support funding for the agency to conduct their statutory responsibilities. It is unclear how a "community ombudsman" would reduce methane emissions from the oil and gas sector.