
EVALUATION OF LDAR AND OTHER EMISSIONS REDUCTION CONTROL STRATEGIES AS PROPOSED BY THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND THE ENVIRONMENT FOR OIL AND GAS SOURCES, JANUARY 2014

1 BACKGROUND OF EXPERIENCE, INVOLVEMENT AND HISTORY

Environmental Defense Fund requested that WZI Inc.(WZI) review and participate in the Colorado Department of Public Health and the Environment proposed rule development for Oil and Gas Sources in order to evaluate the emission reduction strategies including the application of leak detection and repair methodologies. The scope of my study was to determine the practicality of the proposals from a physical scientific perspective, effectiveness, and cost perspective.

In deriving the opinions, certain information was provided to me and I gathered additional information within the scope of review that I determined using my expertise in this field. I reviewed what I consider is an adequate body of information to be confident that my conclusions are scientifically accurate and correct.

In forming opinions, WZI relied on the formal education, experience, and training of its senior executives in the exploration and production industry as well as the experience in reviewing and regulatory process participation of its senior executives. In over three decades of experience working in the United States WZI has permitted and supervised environmental compliance for facilities related to oil and gas production for many companies, participated in the regulatory process in many of the fifty states as well as three foreign countries. The senior executives have actively participated in professional societies and including serving as president of the local Chapter of the Society of Petroleum Engineers. We participated in organizing the joint United States Environmental Protection Agency, Department of Energy and Society of Petroleum Engineers – Environmental Conference on Exploration and Production and we are active contributors to the profession including authoring professional papers, and editing a monograph on Environmental engineering for Exploration and Production. WZI has Registered Engineers, Geologists and Environmental Assessors. A true and correct copy of the senior executives curriculum vitae are attached as **Appendix I, Resumes and CVs**.

2 STATEMENT OF OPINIONS¹

OPINIONS

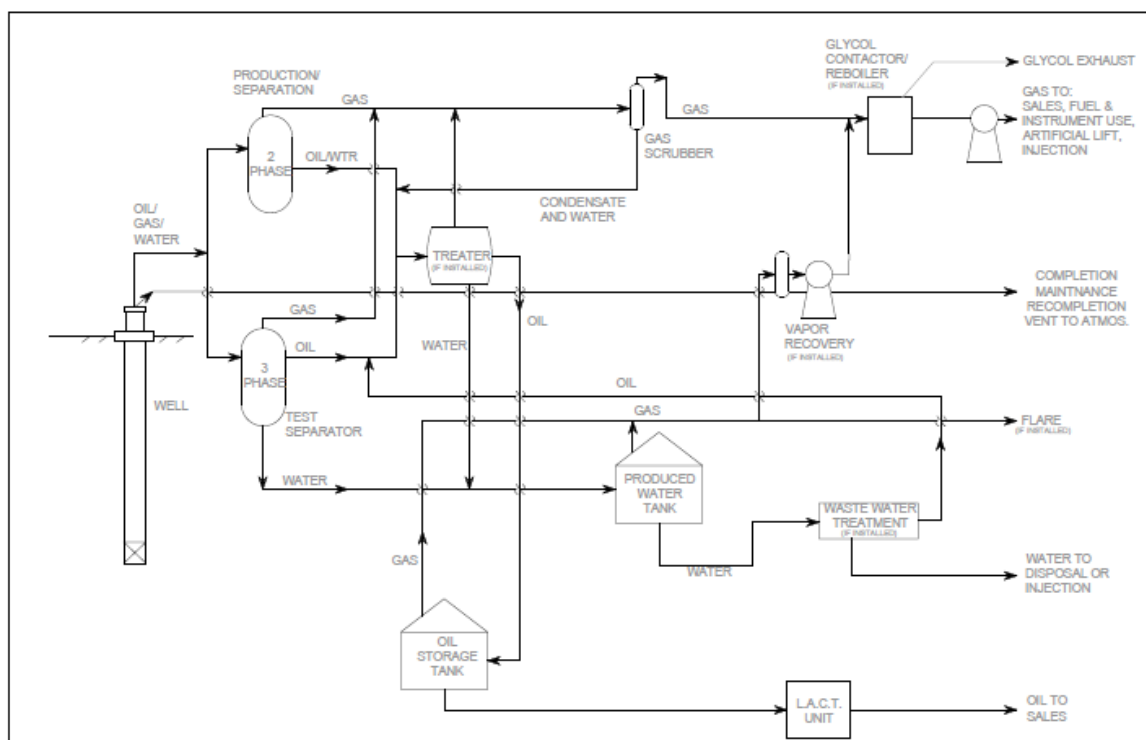
- Emissions from Oil and Gas Facilities are a key source of Volatile Organic Compounds (VOC) and Methane Emissions;
- The proposed Regulation 7 control strategies of Leak Detection and Repair (LDAR) and other oil and gas associated control programs are effective tools in reducing emissions from oil and gas production facilities;
- The Colorado Department of Public Health and the Environment (CDPHE or Department) correctly evaluates the Control Efficiencies (CE) of the proposed LDAR program; and
- The CDPHE cost-effectiveness analysis is in line with industry costs and is reasonable.

3 OPINION 1: EMISSIONS FROM OIL AND GAS FACILITIES ARE A KEY SOURCE OF VOLATILE ORGANIC COMPOUNDS (VOC) AND METHANE EMISSIONS

Review of emission sources related to Oil and Gas production in Colorado

The exploration and production process involves the drilling and completion of wells, the gathering and storage of liquids and gasses and the transportation of these valuable commodities to the refining and public utility markets. Figure 3.1-1 below is a diagram of a typical oil and gas producing facility.

¹ For the purpose of the opinions herein, "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flow lines.

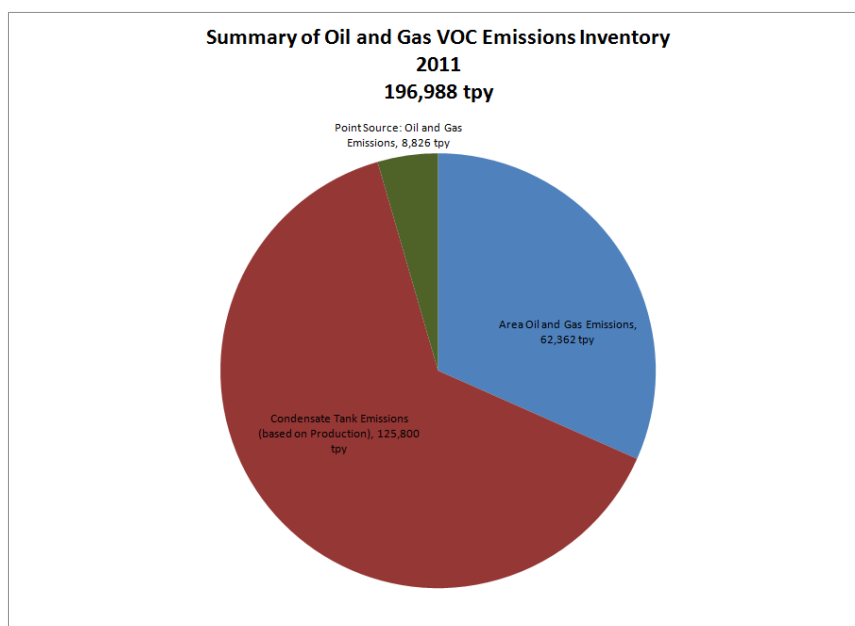


These facilities are a key source of anthropogenic VOCs and methane in Colorado, and are increasing as the development of conventional and unconventional sources of oil and gas continue. For the baseline year (2011), CDPHE estimates the VOC emission inventory at 196,988 tons per year (tpy). Using appropriate conversion factors, methane emissions are estimated to be 325,349 tpy.

The 2011 baseline emissions inventory is a combination of the emissions reported to CDPHE, estimates developed for the State Implementation Plan and production-based condensate tank emissions corrected for Capture Efficiency, Control Effectiveness and Rule Penetration, **Appendix II, Baseline VOC Emissions Data**. The summary **Table 3.1-1** below shows the consolidated data for 2011 Baseline Emissions for both VOC and Methane associated with oil and gas activities for which controls are proposed by emission source.

Table 3.1-1 Baseline Inventory Table 2011					
Item	Short Name	2011 VOC, TPY	2011 Methane, TPY	Ratio VOC : Methane	Emission Source Type
1	Condensate Tanks	125,800	27,588	4.56	Post Flashed Liquid, API >45
2	Fugitives-Oil Well	18,253	65,656	0.28	Process Liquid and Process Gas
3	Pneumatic Devices-Oil Well	13,898	36,342	0.38	Process Gas
4	Blowdowns-Gas Well Venting	11,524	78,985	0.15	Casing Gas
5	Initial Completions-Gas Well Venting	8,760	60,044	0.15	Casing Gas
6	Pneumatic Pumps-Gas Well	4,879	17,549	0.28	Process Gas
7	Point Sources: Others (Produced Water Portion)	2,083	7,492	0.28	General Process Gas
8	Point Sources: Internal and Turbine Combustion (non coal)	2,041	7,342	0.28	NG Fuel
9	Gas Well Truck Loading-NG	1,938	422	4.59	Post Flashed Liquids, API <45
10	Recompletions-Gas Well Venting	1,817	12,589	0.14	Production Gas/Liquid Flash to amb.
11	Point Sources Crude Oil: Submerged Loading (Normal Service)	1,304	284	4.59	Post Flashed Liquids, API <45
12	Point Sources: Glycol Dehydrator Process Emissions	1,051	58	18	Process Gas
13	Point Sources: Oil-Sludge-Waste Water Pit	1,042	680	1.53	Post Flashed Liquids/Water
14	Point Sources: Fugitive Emissions	1,012	3,640	0.28	Process Liquid and Process Gas
15	Compressor Engines-NG	480	1,727	0.28	NG Fuel
16	Miscellaneous Engines	422	1,517	0.28	NG Fuel
17	Point Sources: Flares	293	2,008	0.15	Casing Gas
18	Fugitives: Other	177	637	0.28	Process Liquid and Process Gas
19	Drill Rigs	157	564	0.28	Production Gas/Liquid Flash to amb.
20	Workover Rigs	36	128	0.28	NG Fuel
21	Dehydrators-Gas Well	14	49	0.28	Process Gas
22	Tank Flaring-Condensate	6	42	0.15	Casing Gas
23	NG Liq./Gas Well Wtr Tnk-NG	1	4	0.28	Post Flash Production Mixed Liquids
24	Artificial Lift	0	1	0.25	NG Fuel
25	Heaters-Oil Well	-	-	0.28	NG Fuel
	Total	196,988	325,349		

The figure below shows the relative size of the baseline 2011 VOC Inventory for the three major categories estimated by CDPHE: Point Source Emissions, Condensate Tank Emissions, and Area-wide Emissions reported by CDPHE.



The baseline 2011 inventory is the most recent statewide inventory for all source categories made by CDPHE. However, CDPHE has more recent data available to it for certain

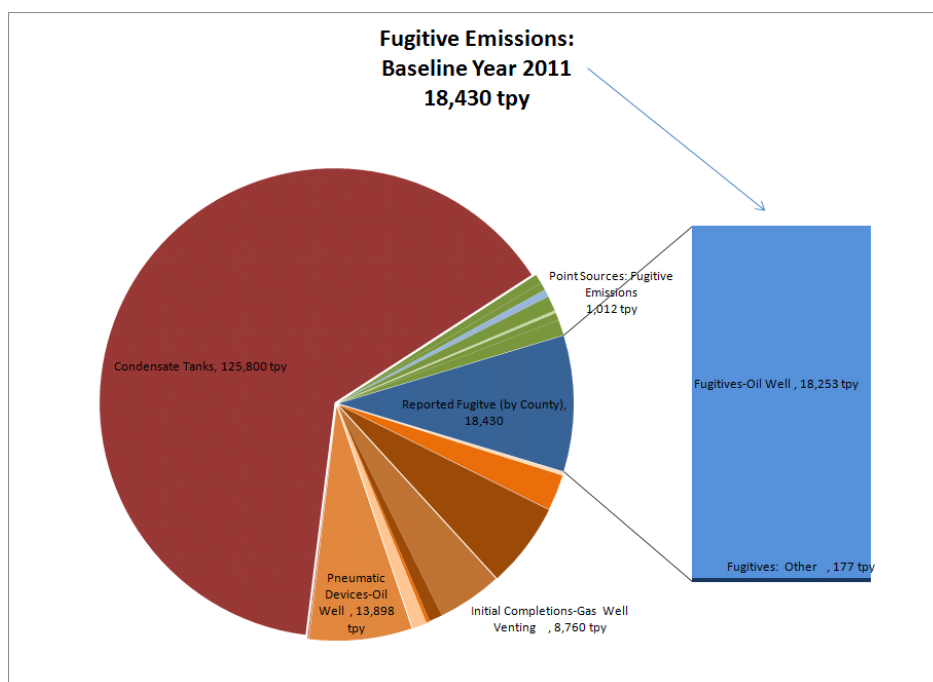
components of the inventory, and that more recent data, if available was used to evaluate the emission reductions of the proposed Regulation modifications.

4 OPINION 2: LDAR AND THE ASSOCIATED EMISSION CONTROL STRATEGIES ARE EFFECTIVE TOOLS IN REDUCING FUGITIVE EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES;

4.1 LDAR IS AN EFFECTIVE TOOL FOR REDUCING FUGITIVE EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES

4.1.1 WHAT ARE FUGITIVE EMISSIONS?

Fugitive emissions are emissions associated with the numerous components surrounding a production well including the associated facilities. Generally, fugitive oil and gas production emissions come from facility “components” (*i. e.* Valves, Flanges, Connectors, Open-ended lines, Pump Seals, Valve Bonnets, Compressor Seals, Pressure Relief Valves, Well Cellars, and Pits). Fugitive emissions are emitted from components that are leaking due to poor integrity, failed condition, or design leakage (seal wetting leakage). In Colorado, the total fugitives VOC emissions for the baseline year of 2011 are 19,442 tpy (18,430 tpy reported as Area-wide sources and 1012 tpy of Point Source Fugitives). These fugitives are the specific target for the elements of the revised regulation related to LDAR. The figure below shows the specific breakdown of fugitive emissions.



4.1.2 HOW HAVE FUGITIVE EMISSIONS BEEN QUANTIFIED?

Fugitive emissions are commonly estimated by using a count of components and emission factors for those types of components and the service of the component (*e.g.* liquid or gas service). EPA in conjunction with industry and other regulatory agencies has developed emission factors for these sources on a per-component-basis. EPA and others have also developed factors to distinguish the amount of VOC and Methane associated with these emissions, using empirical data from studies. The most commonly used emission factors are those presented in EPA Table 4-2, from the 1995 EPA Protocol for Equipment Leak Emission Estimates. These are the values applied by CDPHE in its inventory and proposed rule analysis. The approach used by the CDPHE is a standard way to estimate emissions from these types of facilities, and is an approach WZI has used regularly in its work for the oil and gas industry.

Fugitive emissions depend in part on the number of components at issue. Extensive studies have been conducted that provide information about the typical count of components at oil and gas sites. Component counts are known to vary by facility; a single well head may have as few as 50 components whereas a larger more encompassing facility may have as many as 500 components per facility well, or more.²

The proposed regulation defines “facility” broadly, to encompass all facilities including the wells, on-lease tankage and metering (which has sometimes been excluded from the component counts in other studies). The CDPHE developed a model facility for purposes of its cost estimate that contains 535 components, based on an analysis of APEN data in the state. This estimate is in line with my experience and industry studies.³

As a further example, for compressor stations, industry studies show that compressor stations in oil and gas service have a larger component count (approximately 2,000 to 6,000) depending on the size and service of the facility, **Appendix III, Emission Factors and Component Data**. A review of various facility APEN reports for 2012 shows a similar pattern of component counts in Colorado. The CDPHE assignment of component counts is consistent with the prior industry studies and APEN reports provided by sources in the state.

WZI reviewed the approach to estimate component counts and fugitive emissions calculations done by CDPHE and the approach appears appropriate and reasonable. The estimate of fugitive emission from oil and gas production activities for this rule proposal is reasonable and in accordance with industry standards.

² Historic studies deriving component counts: *i.e.*, WOGA Study, API/Rockwell Study, CARB

³ GRI/EPA study

4.1.3 HOW LDAR WILL REDUCE FUGITIVE EMISSIONS?

Leak Detection and Repair (LDAR) is a systematic emissions control methodology which requires periodic surveying of all physical components that are potential sources for fugitive leaks, and repairing identified leaks to a non-leaking condition.⁴ This methodology is employed in Refineries, Chemical facilities and oil and gas producing operations in other jurisdictions and is often used as part of an Occupational Safety Health Act driven safety program. The proposed Regulation will achieve reductions in the emissions inventory by this common sense approach of systematically checking components for leaks, and fixing leaks that are detected. The proposed Regulation tailors the LDAR frequency, requiring more frequent LDAR at larger sites and less frequent LDAR at smaller sites. The proposed Regulation supplements the instrument-based LDAR with more frequent Audio, Visual and Olfactory (AVO) inspections, which is another means of detecting and fixing leaks, limited by human senses.

A properly implemented LDAR program can reduce emissions, both VOC and Methane, by up to 80%. Among other things, the LDAR program can lead to improved maintenance on components. Examples of steps operators will likely employ as part of their LDAR include, as applicable:

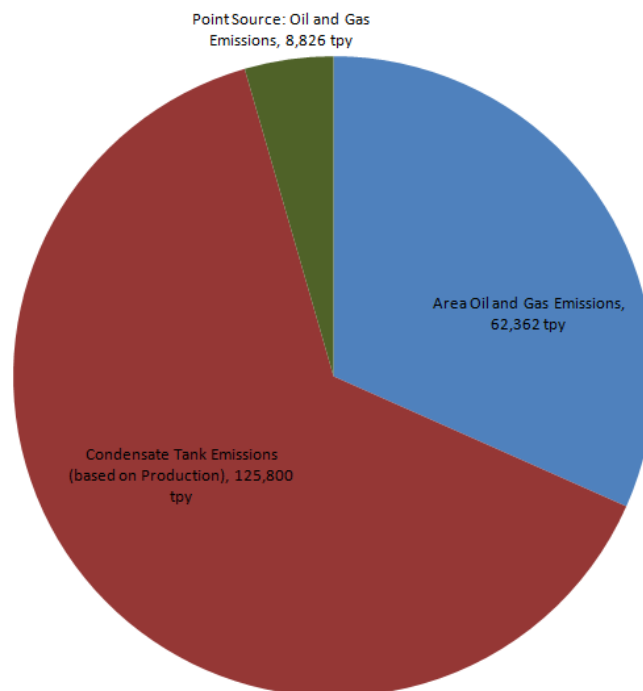
- Cap all open ended connections (except safety related open-ended lines, Vents bleed lines in double block and Bleed service, etc.),
- Tighten all valve bonnets,
- Replace bonnet bolts when signs of stretch or fatigue as exhibited,
- Tighten all packing gland nuts,
- Maintain Wellhead Stuffing boxes,
- Use advanced packing and/or packing lubricant,
- Replace critical valves with sealed bellows units, and
- Install rupture disks on Pressure Safety Valves (PSVs).

4.2 THE PROPOSED STORAGE TANK CONTROL STRATEGIES ARE EFFECTIVE TOOLS IN REDUCING EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES

The largest single source of VOC emissions is estimated by CDPHE to be the Condensate Storage Tanks. Baseline VOC Emissions from Reported Tanks contribute approximately 125,800 tpy for 2011. The relative contribution of storage tanks to the VOC inventory for oil and gas production activity is shown in the pie chart below.

⁴ Non-leaking components are defined by the post repair condition where the threshold is not exceeded. Some components have design leakage.

Summary of Oil and Gas VOC Emissions Inventory 2011



4.2.1 WHAT ARE STORAGE TANK EMISSIONS?

Storage tank emissions are the vapors which escape from the hatches on the tanks as the fluids are produced into them and unloaded out to sale either by pipeline or truck as well as vapors that escape due to diurnal temperature change. There are also components that contribute fugitive emissions in the tank installations as discussed previously. The emissions of concern are both VOCs and Methane.

In Colorado it has been reported that some venting is being caused by operator error (*e.g.* leaving tank hatches open after a gauging event or unloading of a tank) and/or inadequate design which results in loss of product by allowing the hydrocarbon product to escape into the air due to over-pressuring of the tank facilities.

Tank emissions vary based on the manner in which the tank is operated and the type of fluids sent to the tank. Natural gas blanketing may be used in some installations, however, typical operations result in tanks with the following general characteristics:

Condensate Tanks typically have:

- higher vapor pressures;
- higher emissions per barrel; and
- the vapors contain less methane and more VOCs relative to one another than crude oil tanks.

Crude oil tanks typically have:

- lower vapor pressure;
- lower emissions per barrel than a condensate tank; and
- the vapors contain more methane and less VOCs relative to one another than condensate tanks.

Coal Bed Methane Water Tanks typically:

- contain vapors over water unlike condensate or crude oil tanks; and
- the vapors contain very high methane content with a low VOC content.

4.2.2 HOW HAVE STORAGE TANK EMISSIONS BEEN QUANTIFIED?

The previous documented CDPHE VOC inventory related to Storage tanks is smaller than the 2011 baseline inventory. It is limited by the APENs-based data which does not include many tanks that are known to exist but are not necessarily subject to any existing reporting requirement due to thresholds and exemptions.⁵ CDPHE established the 2011 baseline emissions inventory contribution by accounting for all production tanks (both reported and unreported) as well as concerns about inconsistent reporting of actual controls and operations. This 2011 baseline inventory was derived by CDPHE from the total reported production uncontrolled and Colorado-based emissions factors. The 2011 baseline inventory resulted in uncontrolled VOC emissions from tanks of 237,830 tpy. CDPHE then adjusted the uncontrolled emissions for the existing controls already in place in Colorado: 75% for Capture Efficiency, 95% for Control Effectiveness and 80% for Rule Penetration. CDPHE estimated an actual 2011 baseline inventory of 125,800 tpy.⁶ This inventory methodology captures emissions from all oil and condensate liquids-producing wells regardless of size, while accounting for the fact that some tanks are not controlled due to size or other factors (Rule Penetration).

⁵ CDPHE, "Draft CDPHE Methodology for Developing Projected 2018 Oil & Gas Emissions for the Northern Front Range NAA & the Remainder of the State," September, 2013

⁶ 63% of the baseline inventory is in Weld County

Condensate tank VOC emissions were calculated using 2011 COGCC production data⁷ and tank emissions factors developed by Basin.⁸

Basin	Condensate Tank Emissions Factor, lb VOC/bbl ⁹
DJ Basin	13.7
Piceance	10.0
No. San Juan	11.8
Remainder	11.8

Independently, the Texas Environmental Research Consortium (TERC) commissioned a study of oil and gas related tank emissions in Texas. An average emissions factor was reported as 33 lb VOC/ bbl \pm 53 lb VOC/bbl.¹⁰ WZI conducted a rigorous analysis of this empirical data and compared it to the factors utilized by CDPHE, and found that the TERC data when averaged without outliers approaches 15 lb VOC/ bbl \pm 12.5 lb VOC/bbl and is generally consistent with CDPHE's emission factors related to Colorado's regional production.¹¹

WZI reviewed the calculations and found them to be reasonable based on the assumed facility characteristics.

⁷ **Appendix IV, COGCC Well Data, 2011**

⁸ ENVIRON, "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Denver-Julesburg Basin," Prepared for CDPHE and Independent Petroleum Association of Mountain States (IPAMS), April, 2008

⁹ These factors presume that there are no low pressure separators in any tank facilities prior to the tanks and may over estimate the volume of VOCs, **Appendix V Speciation Analysis**. If a low pressure separator is vented prior to the tank, these emissions should be considered as tank emissions.

¹⁰ URS Corporation, FINAL REPORT: VOC Emissions from Oil and Condensate Storage Tanks, Prepared for Texas Environmental Research Consortium (TERC), April, 2009

¹¹ Upon investigation of the TERC data WZI found that the high standard deviation is attributed to outliers whose measurement are suspect, the average is largely skewed by tanks reported as emitting less than 3.5 lb VOC/bbl (likely controlled) and tanks reported as emitting in excess of 60 lb VOC/bbl (likely emitting more VOC [as speciated] into vapor, than physically provided for by K-factors for in the normal petroleum liquid at the specified tank pressure and temperature [8 gallons out of 42 gallons in a barrel, 20%]; only one value was dropped in the study(tank battery 26), exceeding 1200 lb VOC/bbl (using 7.48 lb/gallon this is 162 gallons in a given 42 gallon barrel). The three low measured emissions measurements were treated as possible artifacts of emissions control. On the larger tanks (and smaller tanks as well) tank vapor composition must be in balance with the liquids sent to the tank in accordance to speciations in vapor and liquid phases defined by Equations of State and K-factors, and unless adjunct vapors are injected into the vapor space the samples of vapor pulled should reflect this balance. Additionally (by virtue of conservation of mass) the mass emitted by tank as the VOC component cannot exceed the mass fraction (defined by the K-factor) possible from the liquids prior to the flash in the tank, and certainly cannot exceed the total mass of VOC components available in the Crude Oil or Condensate, as if fully weathered. While it is possible to have high tank emissions (if the tank is the direct recipient of production liquids with no interposing separator), the commensurate vapors would have high Methane content along the lines of the production separation and GOR and the subsequent sampled Vapor speciation would show low VOC and high Methane.

If one simply eliminates the high and low outliers, the TERC average approaches 15 lb VOC/ bbl \pm 12.5 lb VOC/bbl and is consistent with CDPHE's emission factors related to Colorado's regional production.

4.2.3 HOW STORAGE TANK EMISSIONS CAN BE REDUCED AS REQUIRED BY THE RULE (SECTION XVII.C)?

The CDPHE proposal will reduce venting from tanks using a three-pronged approach. First the proposal clarifies that operators must route all emissions to a control device unless venting is reasonably necessary for maintenance, tank gauging, or safety. Second, operators must clarify that their tank systems are designed to meet this requirement. Third, operators must routinely check for open access points and non-functioning control devices during required instrument based inspections (LDAR or AVO).

The revised Regulation will achieve reductions in the inventory by:

- Lowering Tank threshold from 20 tpy to 6 tpy for installation of controls;¹²
- Removing exemption for Produced Water and Crude Storage Tanks;
- Requiring Controls having 95% Capture and 98% Destruction Efficiency (Flare) during the first 90 days of operation;
- Applying Tiered Tank Inspections (i.e., ≥ 6 tpy to ≤ 12 tpy: Annual Inspections, ≥ 12 tpy to ≤ 50 tpy: Quarterly Inspection, > 50 tpy: Monthly Inspection.); and
- Implementing AVO and Storage Tank Emission Management (STEM) plans.

The resultant changes for design and operation of tanks should result in operators taking the following desirable actions, as applicable, which will reduce emissions:

- Close all thief hatches;
- Install or upgrade Vapor Recovery;
- Install Flares;
- Install additional equipment to equalize pressure, such as high low pressure separators or bladders;
- Cap all open ended connections (except safety related open-ended lines, Vents bleed lines in double block and bleed service, etc.);
- Tighten all valve bonnets;
- Replace failing flange bolts;
- Tighten all packing glands; and
- Install rupture disks on PSVs (when appropriate).

These are common sense approaches to reducing emissions from storage tanks. Requiring the routing of all vapors to a control device, requiring certification that tanks are properly designed to meet the no venting requirement and requiring systematic inspections are all practical practices that will reduce emissions from these sources.

¹² Condensate Tanks in all areas of Colorado will be subject to a new uncontrolled 6 tpy VOC threshold for controls (Vapor Capture and Flare), as opposed to the previous 20 tpy threshold (primarily outside the non-attainment area). The tanks subject to controls will have 75% Capture and 95% Destruction Efficiency (Flares).

4.2.3.1 VAPOR CAPTURE AND FLARES FOR TANKS POTENTIALLY EMITTING ABOVE 6 TPY

Vapor Capture is safe and simple in terms of design and operation and used routinely in Colorado and other jurisdictions. Many operations typically use this method to ensure safe operations. The piping and equipment to route captured vapors to a flare (or vapor recovery) may be designed for low pressure service or high pressure service.

4.2.3.2 STORAGE TANK EMISSION MANAGEMENT (STEM)

The STEM program is designed to improve storage tank operations by implementing an individual or systematic protocol that includes monitoring and documentation of a proactive management program to reduce the tank emissions. STEM plan updates will provide the operators with a ready means of identifying certain needed changes in monitoring, equipment design and operating practices, and the facility owners will have a readily available on-site tool for personnel.

4.2.3.3 MONITORING

Separate of STEM plan, the tank operators are required to monitor with AVO all thief hatches and keep them closed except during emergencies, maintenance, gauging. Operators are expected to monitor all tank-related equipment as well as the seals and maintain system integrity, repairing when necessary, regardless of tank size or Potentials to Emit. These practices are good management for any oil and gas production operation.

4.2.3.4 TOTAL TANK RELATED EMISSION REDUCTIONS

For tanks, regardless of service, with the Potential to Emit VOC greater than 6 tpy, the proposed Regulation will require a control value of 95%, and STEM. This is calculated by CDPHE to reduce 58,361 tpy of VOC in Colorado based on the updated inventory.^{13,14} In addition, this volume of VOC reductions would be associated with 12,798 tpy of Methane emission reductions from the tanks.¹⁵ WZI reviewed the calculations of CDPHE and have verified that the reductions from an uncontrolled basis without low pressure separation are reasonable.

4.3 THE PROPOSED PNEUMATIC VALVE REPLACEMENT CONTROL STRATEGIES ARE EFFECTIVE TOOLS IN REDUCING EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES

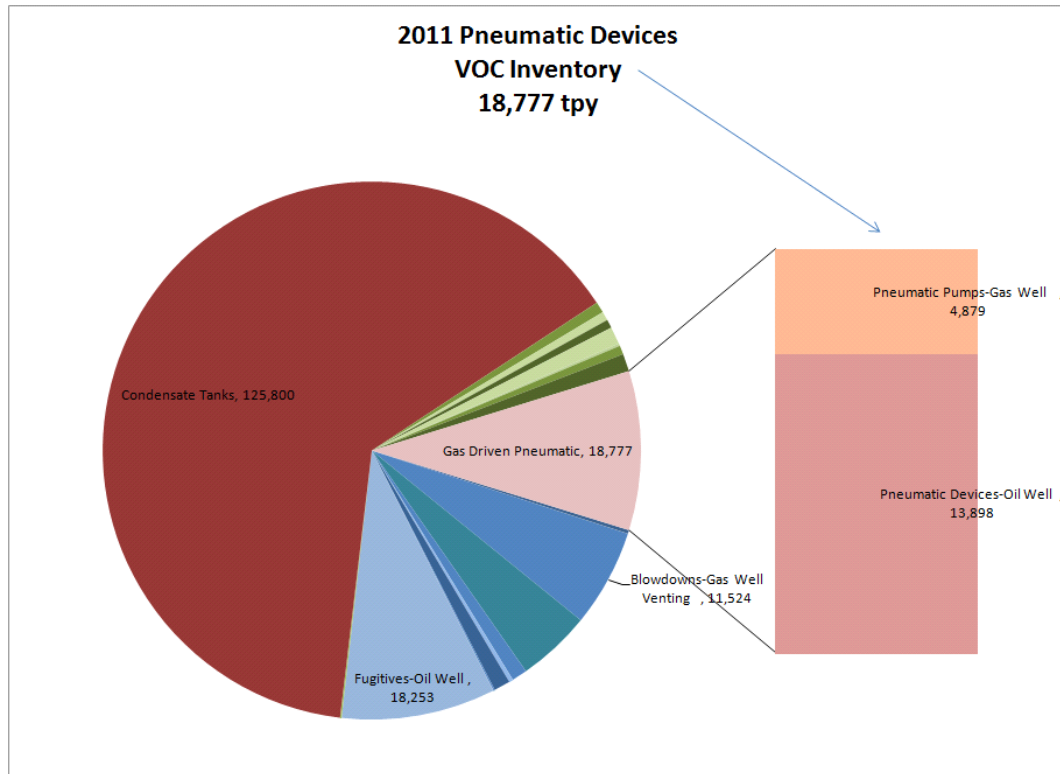
Uncontrolled emissions from 9,834 High Bleed Pneumatic Valves remain a concern in areas not part of the non-attainment area and these remaining Pneumatic Valves contribute

¹³ Regulation 7-Initial Economic Impact Analysis, Tables 3 (lowering threshold from 20 to 6 tpy), 6 (produced water tanks, 9 (oil tanks) and 15 (condensate tank capture efficiency).

¹⁴ Using TSD tank speciation VOC/Methane ratio of 4.56

¹⁵ IBID

approximately 7% of the Total Oil and Gas VOC contribution and 15% of the Total Oil and Gas Methane contribution to the Colorado baseline 2011 inventory. The chart below shows the relative inventory.¹⁶



4.3.1 WHAT ARE PNEUMATIC VALVE EMISSIONS?

Typically, two to four gas operated valves can be found on liquid/gas separator systems in a production facility as part of the multi-phase level control system. These are typically snap-acting valves, set to trigger on level signal from float actuated controllers monitoring the water/oil level and interface. Pneumatic devices are often operated with natural gas. Pneumatic emissions come from the cycling of the control system and the valve actuator in normal operations.

4.3.2 HOW ARE PNEUMATIC VALVE EMISSIONS CALCULATED?

High bleed valves are capable of emitting as much as 30 cubic feet per hour (cfh) of natural gas per valve station due to their design. CDPHE used the IPAMS study results to establish a High-bleed average emission rate of 16.8 cfh and a Low-bleed emissions rate of 1.93 cfh.¹⁷ EPA has been studying the reductions attributed to Pneumatic valve conversions as part of

¹⁶ Using TSD Process Gas speciation, 0.28 lb VOC/lb Methane

¹⁷ Appendix VI Regulation 7 – Initial Economic Analysis

the GasStar program and found similar results.¹⁸ WZI reviewed the 2011 baseline inventory attributed to the pneumatic valves and found it to be reasonable.

4.3.3 HOW FUGITIVE PNEUMATIC EMISSIONS CAN BE REDUCED AS REQUIRED BY THE PROPOSED REGULATION INCLUDING BENEFITS OF NO BLEED DEVICES (SECTION XVIII)

The emissions from pneumatic devices can be controlled by conversion to non-gas control systems or Low-Bleed control technology. These are existing well-established technologies.^{19 20}

The revised Regulation will achieve reductions in the inventory by:

- Requiring 9,384 High-bleed controls valves at pneumatically operated valve stations be converted to Low-bleed or No-bleed; and
- Giving preference to no bleed installation, if technically feasible.

CDPHE has estimated the emission reduction as replacement with Low-bleed technology which is conservative and results in emission reductions of 21,847 tpy of Methane from the IPAMS study. This expected reduction is calculated in a normal manner.²¹ Using the IPAMS speciation for the gas typically used for these devices, the VOC reduction from this retrofit rule for pneumatics will generate a reduction of 6,803 tpy of VOC and 25,936 tpy Methane. These figures are lower for VOCs and higher for Methane than the calculation by the CDPHE.²² This analysis does not affect the cost analysis as the change-out of this equipment is a net gain to the operator within a few years.

¹⁸ **Appendix VII, Lessons Learned from Natural Gas STAR Partners, “Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry”**

¹⁹ CDPHE, Statewide Emissions Calculations, VOC is estimated to be 22% of THC by wt, see speciation discussion below.

²⁰ Reed, Scott, “Best Practices for Using Flares to meet proposed EPA Emissions Regulations for Hydraulically Fractured Natural Gas or Oil Wells”, SPE 157803, 2012

²¹ **Appendix VIII, Pneumatics Statewide Methane Emissions.xlsx**

²² Per conversations with CDPHE, CDPHE estimated their current Methane inventory using projections of well activity and valve counts, additionally CDPHE used different field data for the Natural Gas speciation (other than the IPAMS derived value of 7.4 % VOC by weight) to derive their VOC amount.

4.4 REGULATION 7 RELATED FUGITIVE CONTROL STRATEGIES ARE EFFECTIVE TOOLS IN REDUCING EMISSIONS FROM OTHER ASSOCIATED OIL AND GAS PRODUCTION FACILITIES

4.4.1 NATURAL GAS COMPRESSOR FUGITIVE EMISSIONS

4.4.1.1 WHAT ARE NATURAL GAS COMPRESSOR-RELATED FUGITIVE EMISSIONS?

One source of emissions from Natural Gas compressors is fugitive emissions generally related to components such as valves and connectors, compressor seals and PSVs, as have been discussed previously. As discussed above, these emissions are estimated based on the number and type of components that exist at these facilities.

4.4.1.2 HOW HAVE NATURAL GAS COMPRESSOR EMISSIONS BEEN CALCULATED?

The original inventory from National Emissions Inventory (NEI) data for Natural Gas compressors in Colorado is derived from the reporting facilities using CDPHE Form 203.²³ ²⁴ These data are limited to those facilities subject to reporting requirements. In order to create a more comprehensive inventory for the analysis, CDPHE estimated Natural Gas Compressor fugitive emissions based on a population of 200 qualifying Compressor Stations whose component count and distribution based on thresholds was derived by a review of the available APEN reports.²⁵

4.4.1.3 HOW THESE NATURAL GAS COMPRESSOR-RELATED EMISSIONS CAN BE REDUCED AS REQUIRED BY THE PROPOSED REGULATION (SECTION XVII.F)

The revised Regulation will achieve reductions in the inventory by:

- Requiring Tiered LDAR (i.e., ≤12 tpy: Annual Inspections, ≥12 tpy to ≤50 tpy: Quarterly Inspections, >50 tpy: Monthly Inspections) based on facility uncontrolled emissions

The resultant changes for Natural Gas Compressors should result in operators taking the following desirable actions, as applicable, which will reduce emissions:

- Maintain and/or replace seals;

²³ **Appendix IX, Sample APEN**

²⁴ A review of the 2011/2012 NEI data for facilities reporting greater than 12 tpy VOC indicated that there are 291 permits issued to Natural Gas compressor-related equipment. Many of the permits reported individually exceeding 12 tpy VOC are for the same physical location. It is reasonable to assume these are multiple permits for a specific facility, now subject to the rulemaking. If other smaller equipment at the same physical location are also grouped by locations to apply the threshold then the population of facilities meeting the 12 tpy threshold could easily be 200. NEI data is provided in **Appendix X, NEIdata.xlsx**

²⁵ **Appendix XI, LDAR Cost Analysis – Compressor Station- 14NOV2013.xlsx**

- Cap all open ended connections (except safety related open-ended lines, Vents bleed lines in double block and bleed service, etc.);
- Tighten all valve bonnets,
- Replace failing flange bolts,
- Tighten all packing glands, and
- Install rupture disks on PSVs (where appropriate).

The volume of emission reductions calculated by CDPHE is estimated to be 1,027 tpy²⁶ of VOC and 2,408 tpy of Methane utilizing the LDAR component of the rule only.

4.4.2 GLYCOL DEHYDRATOR FUGITIVE AND PROCESS EMISSIONS

4.4.2.1 WHAT ARE GLYCOL DEHYDRATOR EMISSIONS?

Glycol dehydration is required to remove water from natural gas in order to make it market quality. Glycol dehydration relies on the selective solubility of water in glycol solutions. The glycol is regenerated by desorption/stripping. Most Glycol emissions are related to process emissions due to regeneration of the glycol. Some fugitives do exist due to component leaks and Natural Gas operated pneumatic control valves. CDPHE 2011 baseline inventory reports 1,065 tpy of VOC which corresponds to 102 tpy of Methane related to glycol dehydration. These numbers include the current known population of glycol dehydrators including their emissions control.²⁷ Glycol dehydration VOCs can contain benzene, (a known carcinogen), at higher concentrations than other oil and gas production operations.

4.4.2.2 HOW HAVE GLYCOL DEHYDRATOR EMISSIONS BEEN CALCULATED?

Glycol dehydrator process emissions are calculated using accepted process simulation programs such as GlyCalc or Prosim. Fugitive emissions from the equipment are calculated using the adopted component-based fugitive emissions factors. The VOC:Methane ratio is 18 (*i.e.*, relatively low in VOC content) similar to production gas that has been dried by separator.

To establish an inventory for analysis CDPHE used their APEN reports and found records for 615 glycol dehydrators, some of which have controls in place.²⁸ CDPHE identified 433 known uncontrolled dehydrators with emissions below 15 tpy VOC and calculated the total uncontrolled process emissions from these glycol dehydrators based on size (*i.e.*, 1,827 tpy VOC for units ≥ 2 tpy and 1,550 tpy VOC for units ≥ 6 tpy).²⁹ This corresponds to approximately 96 tpy and 81 tpy of Methane, respectively.

²⁶ This number is reduced slightly from the CDPHE value based on using a smaller sample size in order to eliminate apparent operator reporting errors in the APEN reports.

²⁷ Initial Economic Impact Analysis. The CDPHE uses uncontrolled emissions for their basis.

²⁸ Current state rules require control (to 90%) of glycol dehydrators where the sum of the uncontrolled emissions at the facility exceed 15 tpy of VOC.

²⁹ Using TSD speciation ratio for VOC/Methane for Process gas, 1,827 tpy VOC / 18=96 tpy Methane

4.4.2.3 HOW GLYCOL DEHYDRATOR EMISSIONS CAN BE REDUCED AS REQUIRED BY THE RULE (SECTION XVII.D)

The proposed Regulation will achieve reductions in the inventory by:

- Requiring that existing dehydrators with uncontrolled emissions ≥ 6 tpy achieve 95% control of emissions, and if a flare is used, it shall have a design destruction efficiency of 98%;
- Requiring that existing dehydrators located within 1320 feet of a building unit or other designated areas, control emissions to 95% where the uncontrolled emissions are equal to or greater than 2 tpy which is appropriate for these areas; and
- Requiring new dehydrators with more than 2 tpy uncontrolled emissions to control emissions by 95%.

In all such cases, if a combustion device is used, it is proposed have a rated destruction efficiency of 98% for hydrocarbons.

The resultant changes for Glycol Dehydrators should result in operators taking the following desirable actions, as applicable, which will result in emission reductions:

- 95% control of emissions from glycol dehydrators greater than 2 tpy in proximity to urbanization (as defined) and 6 tpy elsewhere; and
- Reduction in potential health impacts due to benzene exposures.

The results show that the proposed regulations would reduce the emissions from this population by a range of 1,472 tpy VOC to 1,736 tpy VOC (81 and 96 tpy Methane) based on facilities situated near urban and non-urban areas.

The changes required by the proposed Regulation will utilize technology widely employed to control such emissions. These controls are practical and cost effective.

4.4.3 WELL MAINTENANCE VENTING EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES

4.4.3.1 WHAT ARE WELL MAINTENANCE VENTING EMISSIONS

Venting emissions are methane rich releases related to Natural Gas separating from well-related liquids during well blow-downs and other maintenance activities. A well blow-down involves removing the accumulation of undesirable liquids, primarily water or sometimes condensate, from the well bore to improve gas production.

CDPHE has estimated the 2011 baseline inventory from well blow-downs as 11,524 tpy VOCs and 78,985 tpy of Methane.³⁰ This figure does not include emissions associated with other well maintenance activities.

4.4.3.2 HOW ARE WELL VENTING MAINTENANCE EMISSIONS CALCULATED?

Well venting emissions are calculated using production vapor liquid data and the volume of the well, coupled with the number of various events requiring venting. CDPHE has relied on a projection from the 2008 Colorado methane emissions inventory to estimate the 2011 baseline inventory from these well venting.³¹ This is considered to be an approximate figure only.

4.4.3.3 HOW WELL MAINTENANCE EMISSIONS CAN BE REDUCED AS REQUIRED BY THE RULE (SECTION XVII.- H)

The revised Regulation will achieve reductions in the inventory by among other things:

- Requiring liquids removal (blow-down/liquids load-out) by Best Management Practices such as using better lift technologies and down hole configurations, packers to reduce or eliminate the adverse accumulation of liquids.

The resultant changes for well venting should result in operators taking the following desirable actions, as applicable, which will reduce emissions:

- Maintain and/or replace packers
- Install better lift technology
- Use temporary flares, and
- Under the other facility-wide design, operators may elect to capture the maintenance blow-down and route it to the vapor recovery and flare system that is already required as part of their revised Regulation 7 requirements.

EPA Natural Gas Star program partners have reported progress in developing several useful technologies in reducing the degree to which blow-down occurs. Using Plunger Lifts saves about 124 tpy per well of Methane³², Using Vapor Recovery for Casing Vents saves about 193 tpy per well of Methane³³, Vapor Recovery on Casings, Reduced Emissions Completions saves about 286 tpy per completion or recompletion of Methane.³⁴ The well venting

³⁰ Using dry gas speciation ratio for VOC/Methane of 0.15.

³¹ EPA Inventory of U.S.Greenhouse Gas Emissions and Sinks, 1990-2009, April, 2011, EPA uses 9,175 mscf per completion event, Colorado reported 9,306 tons VOC per year for well blow-downs in 2008.

³² **Appendix XII Gas Star Plunger Lifts...4,700Mcf/unit converts to approximately 124 tpy of dry gas assumed to be Methane.**

³³ **XIII Gas Star VRU on Casing...7,300Mcf/unit converts to approximately 193 tpy of dry gas assumed to be Methane.**

³⁴ **Appendix XIV Gas Star Reduced Emissions Completion...10,800Mcf/completion converts to approximately 286 tpy of dry gas assumed to be Methane.**

emissions and the savings in natural gas that will result from Best Management Practices are highly dependent on the individual well characteristics. The proposed regulations which proscribe Best Management Practices provide the needed flexibility.

The volume of reduction in emissions from these practices is unknown at this time. Further study as the rule progresses and Best Management Practices mature is warranted to determine the actual emissions associated with well venting and volume that may be reduced utilizing Best Management Practices. Based on current information, it is reasonable to assume that these programs will achieve at least a 25% reduction, which results in a reduction of 2,281tpy of VOC and 19,746 tpy of Methane.

In addition, the proposed regulation prohibits venting of natural gas from newly drilled oil and gas well separators and requires either connection to a gas gathering line or utilization of a flare (either permanent or temporary) as is appropriate. This is a practical and safe control methodology.

4.5 FLARES ARE EFFECTIVE TOOLS IN REDUCING EMISSIONS FROM OIL AND GAS PRODUCTION FACILITIES

4.5.1 WHAT ARE FLARE EMISSIONS?

Most flare emissions are combustion emissions. Very few component-related fugitives are released by the flare system and most vapor recovery piping is low-pressure. Flares are useful in converting otherwise fugitive and vented VOC and Methane emissions into primarily CO₂, and water. Igniter failure or poor management of the flares is key contributor to VOC and Methane emissions by allowing the gas to by-pass the flare without combustion.

4.5.2 HOW HAVE FLARE EMISSIONS BEEN CALCULATED?

Flare emissions are calculated based on the volume of combusted volume of VOC and Methane for NO_x, PM₁₀, CO₂, SO_x, and VOC combined with the destruction efficiency of the system. CDPHE utilized common industry calculations to define the 2011 baseline inventory for flares including a 3 % lack of flare ignition factor.

4.5.3 HOW FLARE EMISSIONS CAN BE REDUCED AS REQUIRED BY THE RULE (SECTION XVII.C)?

The types of hydrocarbon sent to a flare in oil and gas production has a large concentration of highly combustible Methane and the VOC. This typically leads to destruction efficiencies of at least 98% in a properly maintained flare system.

The proposed Regulation will achieve reductions in the inventory by:

- Requiring all flares to have auto-igniters; and
- Requiring flares to have a 98% design destruction efficiency.

The resultant changes for flares related systems should result in operators taking the following desirable actions, as applicable, which will reduce emissions:

- Under the other facility-wide design, operators under exemptions may elect to capture the facility emissions and route them via vapor recovery to a functional flare system;
- More accurately reflects the true efficiency of the flares being used in the field; and
- Prevention of lack of ignition due to auto-igniters.

The emission reductions estimated are from reducing the failure of flares to ignite in the entire state inventory of flares. The emission reduction is estimated to be 1,136.6 tpy of VOC and 1,895 tpy of Methane.³⁵ The installation of auto-igniters is a practical control methodology.

5 OPINION 3: CDPHE CORRECTLY EVALUATES THE CONTROL EFFECTIVENESS (CE) OF THE PROPOSED LDAR PROGRAM

By definition the Control Effectiveness (CE)³⁶ measures the performance of a proposed regulatory scheme in the context of the uncontrolled condition. In the case of air emissions, it measures the reduction in the air inventory relative to the uncontrolled inventory of emissions (from the proposed regulated body of equipment operating prior to implementation) extrapolated to account for the current population of regulated equipment and is expressed in terms of percent.

³⁵ Using weighted average speciation of the entire inventory (including Condensate Storage Tanks) capable of being routed to a flare, the ratio for VOC/Methane for averaged emissions is 0.6, 1,137 tpy VOC / 0.6= 1,895 tpy Methane

³⁶ "Control Efficiency" and "Control Effectiveness" have been utilized by numerous stakeholders including CDPHE interchangeably. For this opinion I am defining "Control Effectiveness" as the percent reduction achieved by LDAR.

Industry and EPA reviews of maintenance programs such as those related to Planned Maintenance, LDAR and Directed Maintenance have consistently shown what one would expect from an engineering perspective, that the shorter the interval between events for monitoring for failure, scheduled maintenance or repair the better the Control Effectiveness. CDPHE has estimated LDAR control efficiencies as 40% for one-time and annual inspections, 60% for quarterly inspections and 80% for monthly inspections. This is in line with both industry and regulatory historic norms, **Appendix XV, Effectiveness Analysis**.

6 OPINION 4: THE CDPHE COST-EFFECTIVENESS ANALYSIS IS IN LINE WITH INDUSTRY COSTS AND IS REASONABLE SUMMARY OF PROPOSED REGULATORY CONTROLS

6.1 LDAR AS A COST-EFFECTIVE TOOL IN REDUCING FUGITIVE EMISSIONS

LDAR is a cost effective and common sense approach to reducing emissions from oil and gas operations. The use of FLIR technology is becoming more widely available and is commonly accepted making LDAR a more practical and readily achievable element in planned maintenance and repair.

WZI reviewed the CDPHE cost effectiveness analysis, and it is our opinion that the estimate demonstrates that LDAR is cost effective. Some key assumptions used in the analysis include:

1. CDPHE derives a rolled up all-in cost reduced to an hourly basis of \$99/hour. This value includes appropriate cost elements, such as a FLIR camera, a PID device, a vehicle and inspector time (at a salary of \$75,000, with markups for supervision (20%), overhead (10%), travel (15%), recordkeeping (10%), reporting (10%), and fringe benefits (30%)). LDAR cameras are priced at \$120,000 per unit, which is also the appropriate price for such devices. CDPHE assumes a 5 year useful life for the equipment and a 6% interest rate for 5 years. Such equipment can be expected to have a useful life that is longer than five years. These values appear reasonable estimates for these elements. A statewide program will drive economies of scale, competition, and would be expected to drive these prices down.
2. The CDPHE assumed that an operator would require 15 seconds per component using FLIR and 30 seconds per component using the more traditional Method 21 approach with a PID. In my experience, 30 seconds per component is reasonable for an experienced operator using Method 21 in a program of this type, and FLIR should be able to be completed more quickly than Method 21.
3. The Division did not include the savings that would accrue to the operator from the LDAR program, since valuable product would be captured and sold (both condensate

liquids and methane). Nor did the Division include the cost of the repairs, which was imbedded in the assumed hourly rate.³⁷

4. CDPHE estimates the LDAR of the program will reduce VOC emissions by 14,153 tpy VOC, at \$818/ton VOC using a combination of the more expensive per hour Method 21 and the less expensive FLIR.³⁸ This CDPHE analysis assumes a reduction of 40% for annual LDAR, 60% for quarterly LDAR and 80% for monthly LDAR.

The actual cost for each site will vary based on a number of factors, and reflect a range of inspection times for both Method 21 and FLIR, some repair costs, and a credit for recovered product value. While parties can debate the details of the estimate, the estimate shows that the LDAR program would be cost effective. Even if the estimate is off by a factor of five, LDAR would still be less than \$5000 per ton of VOC reduction. LDAR has been found to be cost effective in other jurisdictions at similar cost effectiveness thresholds.

CDPHE did not account for the reduction of Methane in its cost effectiveness analysis. The volume of Methane reduction related to the 14,153 tpy of VOC is 50,546 tpy at no additional cost.

6.2 FACILITY-RELATED TANK EMISSION CONTROLS ARE COST-EFFECTIVE

The cost effectiveness of tank emissions controls rests mainly in the capture of vents and the use of flares. Vapor Recovery Units VRU may cost approximately \$100,000 to install and Flares are expected to cost approximately \$20,000.³⁹ These values are in line with values used by CDPHE.

CDPHE estimated 15 year annualized costs for VRU and flares to be \$19,341 and \$6,287, respectively. CDPHE estimated the cost-effectiveness for VRU to range from \$443/ ton VOC (for new tanks) to a maximum of \$4,658/ton VOC (assuming a 6 tpy tank) and Flares to be \$716 (\$427 for Crude Oil).

³⁷ In my experience, including both the value of the product recovered in conjunction with the cost of repair would not materially affect the cost estimate. Many repairs can be completed at very low or no cost and have significant savings. Some repairs will be more expensive but on an overall basis the net effect will have little impact on the overall cost of the program.

³⁸ Per telephone conversation, Curtis Taiple. The CDPHE estimate for fugitive emissions varies by methodology. In the case of the cost-effectiveness analysis, CDPHE used the quantity of tank based facilities and assumed 2.3 wells per facility with 4.6 tons VOC per tank-based facility.

In the case of the overall inventory's area wide source emission estimate, CDPHE used the IPAMS factors derived for the DJ basin, extrapolated to other basins using survey data accounting for more tanks and wells, thus resulting in a slightly higher value for VOC in the Colorado Inventory.

³⁹ Personal communications with industry equipment providers.

6.3 PNEUMATIC DEVICES CONVERSIONS ARE COST-EFFECTIVE

Replacement of high bleed pneumatic devices with low bleed or no bleed devices is highly cost effective. The cost of replacement is in the range of \$1400 per valve, including the cost of the device and installation. Using a value of \$3.50 /MMbtu for wellhead gas, the replacement will generate \$456 a year in recovered product, per valve replaced. The replacement therefore pays for itself within three years:

$$\frac{\$1,400}{\$456 \text{ per year}} = 3 \text{ years}$$

This is commonly considered a suitable economic hurdle for facility improvement projects. As has been shown by previous GasStar studies operators should consider the merit of this low-cost investment.

6.4 GLYCOL DEHYDRATOR EMISSIONS CONTROLS ARE COST-EFFECTIVE

The control of Glycol Dehydrator still vents, vents from flash that are not able to be condensed is assumed to be routed to a flare to meet the 95% destruction efficiency. CDPHE addressed the glycol dehydrator flare costs by allocating the Fixed Costs of \$19,187 Equipment Costs and \$8,628 Installation and the Variable Costs: \$2,965 over 15 years. Piping and installation costs may vary to some degree depending on facility layout.

CDPHE estimated two cost effectiveness values: one based on the facilities near urban populations and another for the facilities at more remote locations, the table below shows the results.

Threshold	Facilities	VOC Reductions	Methane Reductions	Cost-effectiveness
		tpy VOC	tpy Methane*	\$/ton VOC
2 to 15 tpy	217	1,736	96	\$786
6 to 15 tpy	148	1,472	81	\$632

*Not calculated by CDPHE. This value was derived using TSD speciation ratios 8 to 28 for VOC/Methane for Process Gas.

Based on the estimate of emissions to be controlled, CDPHE correctly analyzes the cost-effectiveness.

7 CONCLUSION

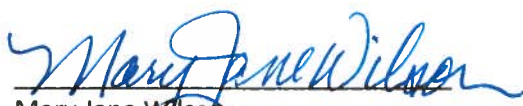
The proposed rules are practical from a physical, scientific, and cost perspective. The measures will generate reductions in VOCs and Methane. The following Table 7-1, Summary Table lists the reductions by category of control and equipment type as discussed in the opinions.

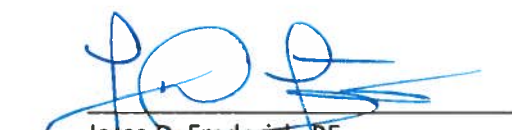
Table 7-1 Summary Table: Inventory Impacts						
	Revised Inventory, tpy		VOC/ Meth.	Estimated Reduction, tpy		Notes
	VOC	Methane		VOC	Methane	
LDAR	19442	69436	0.28	14,153	50,546	Excludes one time LDAR at smallest sites, which would generate an additional reduction of 5,170 tons of VOC and 1164 tons of methane
Tanks	125800	27588	4.56	58,361	12,799	Groups all tank reductions together
Pneumatic Devices	18777	67061	0.28	6,803	25,936	Based on Process Gas, IPAMS and 359scf/lbmole
Compressor Stations	2171	4846	0.448	1,027	2,408	VOC/Methane by CDPHE
Glycol Dehydrators (assumes all units 2 to 15 tpy are located in designated areas)	1828	102	0.28	1,736	96	
Glycol Dehydrators (assumes none of the units 2 to 15 tpy are located in designated areas)			0.28	1,472	81	
Well Venting	11,524	78,985	0.15	2,881	19,207	25% eliminated from inventory, not estimated by CDPHE
Flares	1,430	2,384	0.6	1,136	1,893	3% in inventory VOC/Meth = wtd. avg.
Total (assumes all glycol units near designated areas triggering smaller threshold)	193,098	250,402		86,097	112,885	
Total (assumes no glycol units near designated areas triggering smaller threshold)				85,833	112,870	

Table 7-2 shows the cost effectiveness as described by CDPHE being substantially below the threshold of \$5,000 /ton VOC. These types of controls are not unusual for the Oil and Gas industry in other jurisdictions. The flexibility provided by the proposed Regulation 7 will allow creative emissions reductions.

Table 7-2 Summary Table: Cost-effectiveness				
	Estimated Reduction		Cost-Effectiveness	Notes
	VOC tpy	Methane tpy	\$/ton VOC reduced	
LDAR	14,153	50,546	\$818	Methane without the VOC has a cost effectiveness of \$229/ton
Tanks	58,361	12,798	\$427 to \$4,468	Highest value applies to 6tpy tanks
Pneumatic Devices	6,803	25,936	\$0	Investment recovery, project payout in 3 years
Compressor Stations	1,027	2,408	\$1,449	VOC/Methane by CDPHE
Glycol Dehydrators-urban	1,736	96	\$786	2 tpy to 6 tpy
Glycol Dehydrators-remote	1,472	81	\$632	>6 tpy
Well Venting	2,881	19,207	No value	25% eliminated from inventory, not estimated by CDPHE
Flares	1,136	1,893	\$272	For auto-igniter applied to 3% in inventory VOC/Meth = wtd. avg.
Total ⁴⁰	86,097	112,885		Urban Glycol Units
	85,833	112,870		Remote Glycol Units

*The impacts relate only to activities affected by the regulatory proposal.


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⁴⁰ The difference in the calculation of the emission reductions between WZI and CDPHE is within the accuracy of the inventory.